Réponses du Distributeur et du Transporteur à la demande de renseignements numéro 1 de l'Association québécoise des consommateurs industriels d'électricité et du Conseil de l'industrie forestière du Québec (« AQCIE-CIFQ »)

Annexes

Réponse à la question 1.1

Annexe A

INCENTIVE RATEMAKING REPORT

Prepared for: Enbridge Gas Distribution

CONCENTRIC ENERGY ADVISORS, INC.

JUNE 28, 2013

INCENTIVE RATEMAKING REPORT

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Concentric Energy Advisors, Inc. is an employee-owned management consulting and financial advisory firm focused on the North American energy industry. We offer a broad range of advisory and support services to clients including private and municipal utilities, governmental agencies, financial institutions and industry investors.

Concentric's regulatory experts are closely attuned to the latest rate-setting practices, policies and trends in North America, including the interface of integrated resource planning with ratemaking, the application of rate designs to achieve policy objectives, resource planning and development to achieve environmental and economic policy goals, and alternative regulation mechanisms, including vertical segregation, the introduction of competitive forces into regulated markets, and efficiency-based regulatory incentive mechanisms.

Our ratemaking services range from high level rate case assistance (e.g., case management, stakeholder communications, witness training) to addressing specific technical rate case requirements (e.g., revenue requirements, cash working capital, cost of service studies, marginal cost studies and pricing, rate design, tariff design, cost of capital, attrition of earnings, management prudence, and rate base (including the fair value of rate base assets)). Concentric's consultants also have experience in alternative ratemaking proceedings, including incentive ratemaking approaches, revenue decoupling, capital spending recovery mechanisms, and inflation adjustment mechanisms.

Concentric's regulatory and financial experts have appeared as expert witnesses in most U.S. and Canadian jurisdictions on ratemaking and policy-related issues. The firm is led by senior experts with experience from utilities, government, regulation and finance, supported by a team of consultants and analysts specializing in the financial, economic and technical analysis required for regulatory proceedings.

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APPENDICES

I. EXECUTIVE SUMMARY

This report summarizes the research and analysis conducted by Concentric Energy Advisors ("Concentric") for Enbridge Gas Distribution, Inc. ("Enbridge", "EGD," or the "Company") to assist with the development of the Company's proposed 2nd Generation Incentive Regulation ("IR") plan, which the Company is referring to as a "Customized IR" plan. Our work focused on assisting Enbridge with the development of a proposed plan that would be consistent with the Ontario Energy Board's ("OEB") objectives for such plans, recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs, including Enbridge's 1st Generation plan.

Incentivizing productivity is a key element of any IR plan. In order to promote productivity and efficiency in utility operations, the regulator, company and stakeholders all require an understanding of the baseline starting point, and realistic expectations for what is possible in the future. To create this baseline, Concentric conducted a series of analyses. First, we benchmarked Enbridge's performance across a variety of operating and financial metrics over the 2000 to 2011 period in relation to a group of gas distribution peer group companies. Second, we measured the productivity of the industry and Enbridge over the same period using a total factor productivity "TFP" analysis that measures the efficiency of a utility in converting all of its inputs (labour, capital and materials) into outputs (customers serviced). Third, we narrowed the scope of the examination to focus on O&M expenses only (excluding capital), with a partial factor productivity ("PFP") analysis. These TFP and PFP analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group[1] that could be utilized to test parameters for the Customized IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016[2] costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile.

Results from Concentric's cost benchmarking analysis indicate that EGD is among the most efficient of its industry peers, especially related to O&M and labour costs, although EGD's net plant costs per customer are at the higher end of the industry study group examined.

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1 The industry peer groups used for benchmarking and productivity analyses were similar, however some companies that were used in the benchmarking analysis were excluded from the productivity analyses due to data limitations.

2 While Enbridge is proposing a five year term (2014 to 2018) for the Customized IR plan, Concentric's analyses focused on the 2014 to 2016 period, which corresponds to the period for which "final" Allowed Revenue amounts will be fixed in this proceeding.

Regarding trends in EGD's performance relative to the industry study group over the 2000 to 2011 period examined, Enbridge has generally sustained or improved its cost position in relation to its peers, including during the most recent IR plan period.

Concentric prepared separate TFP and PFP indexes for EGD, for an industry study group, and a seven company sub-group of the largest and fastest growing companies that more closely resemble Enbridge's profile. Productivity is specified as the difference between output growth and input growth, and a productivity index is calculated from annual changes. These results are summarized in Figure 1 for the entire period, and also broken out for the pre-IR period and during the IR period for comparison. The "during IR" period coincides with Enbridge's 1st Generation IR plan.

Figure 1: TFP and PFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Average Annual Growth Rates					
		Industry Study Group		Seven Company Sub-Group		EGD	
		TFP Growth Rate	PFP Growth Rate	TFP Growth Rate	PFP Growth Rate	TFP Growth Rate	PFP Growth Rate
Whole Period	2000-2011	-0.32%	-0.25%	-0.01%	-0.02%	-0.28%	0.50%
Pre-IR	2000-2007	0.19%	0.47%	0.43%	0.74%	-0.06%	0.44%
During IR	2007-2011	-1.22%	-1.52%	-0.78%	-1.33%	-0.66%	0.60%

Figure 1 demonstrates that over the entire 2000 to 2011 study period, the seven company sub-group TFP growth rate, -0.01%, is higher than EGD's TFP growth rate of -0.28%, and higher than the 25 company industry study group TFP growth rate of -0.32%. These results indicate that, in general, the largest and fastest growing companies were more efficient in terms of converting inputs to outputs, but at best, productivity was flat to negative over this period. However, the decline in EGD's TFP growth rate from 2000 to 2007 compared to 2007 to 2011 was less than the industry group's TFP growth rate decline and also less than the seven company sub-group's TFP growth rate decline. As a result, Enbridge outperformed both industry groups over the most recent period.

Over the entire 2000 to 2011 study period, the seven company sub-group PFP growth rate, -0.02%, is higher than the 25 company industry study group PFP growth rate, -0.25%, which indicates greater PFP growth for the seven company sub-group. For the same period of 2000 to 2011, EGD's PFP rate, 0.50%, is significantly higher than both the industry study group average and the seven company sub-group average, indicating that Enbridge was more productive than both groups in converting O&M inputs to customers serviced. PFP growth rates from 2007 to 2011 were less than PFP growth rates from 2000 to 2007 for both the industry study group and the seven company sub-group, however EGD's PFP improved by 0.16% between 2000 to 2007 and 2007 to 2011.

EGD's TFP and PFP improvement between 2000 to 2007 and 2007 to 2011 may be attributable to (a) the incentives for efficiency improvements that resulted from EGD's 1st Generation IR, and (b) EGD's relatively high output growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

The analysis of productivity provided by Concentric serves two roles in EGD's proposed Customized IR plan: (1) the seven company sub-group TFP was used to evaluate the sufficiency of an I-X rate path against EGD's projected costs; and (2) the seven company sub-group PFP was used to evaluate the productivity embedded in EGD's O&M expense projection. Concentric's benchmarking analysis demonstrated that EGD is currently an efficient utility and that EGD has continued to improve its performance relative to its industry peers, especially related to O&M costs. Furthermore, Concentric's productivity analysis demonstrated that EGD improved its productivity as measured by both TFP and PFP during the 1st Generation IR plan (2007 – 2011) compared to the pre-IR plan period (2000 to 2007) relative to performance of both the 25 company industry study group and the seven company sub-group during those same periods, which indicates that EGD made productivity improvements during the 1st Generation IR plan. This also suggests that the relatively "easy" productivity improvements that are often available at the onset of IR may not be as available to EGD in the 2nd Generation IR. While it is important that EGD continue to look for additional efficiency and productivity improvement opportunities, they may be more difficult for EGD to find. Based on Concentric's TFP and PFP analyses, Concentric recommends an X Factor of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan.

There are two common approaches to developing the inflation factor ("I Factor") used in I-X type formulas: (1) using a single macroeconomic index; or (2) using a composite I Factor. Concentric considered the benefits of the continued use of the existing GDP-IPI-FDD inflator versus a composite factor to evaluate the Allowed Revenue amounts for EGD's Customized IR plan. In doing so, Concentric researched a broad array of potential indices and examined their sources, components, and availability. Based on the availability of price indexes that more specifically reflect labour and capital costs, and the historical evidence that illustrates the potential for these cost indices to diverge from the general rate of inflation, we believe it is appropriate to utilize those more specific indices to reflect price changes in those specific inputs. We recommend a composite I Factor comprised of a weighted average of (1) the Ontario Average Hourly Wages (all employees) for labour-related prices, (2) Canada GDP-IPI-FDD for materials prices, and (3) Canada implicit price index for net gas distribution plant.

To test the reasonableness of EGD's 2014 to 2016 O&M forecast, Concentric performed two evaluations. First, Concentric compared EGD's 2014 to 2016 forecast O&M cost per customer to EGD's historical trend of O&M costs per customer and to the O&M cost per customer of the cost benchmarking study group. EGD's projected 2014 to 2016 O&M cost per customer is higher than recent history, but not by a significant amount, and is below the industry study group average. For the second analysis, Concentric compared EGD's 2014 to 2016 forecast O&M cost per customer with the O&M cost per customer that would be derived from applying the I-X growth rates from the PFP study. On balance, EGD's projected O&M costs are lower than the PFP I-X trajectory by approximately $12 million over the three years 2014 to 2016. EGD's projected O&M cost per customer is higher than the O&M cost per customer derived from applying the PFP I-X formula in 2014 and is lower than the O&M cost per customer derived by applying the PFP I-X formula in 2015 and 2016. The results of Concentric's analyses indicate that EGD's projected 2014 to 2016 O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to productivity from the seven company sub-group PFP analysis.

Concentric prepared a separate quantitative analysis of capital-related revenue requirements and revenues. The quantitative analysis for Concentric's assessment of EGD's proposed capital cost recovery approach is based on the results of models that Concentric developed to (a) determine the capital-related revenue requirements of EGD's projected rate base and plant balances during the 2014 to 2016 period, and (b) calculate the projected revenues during the 2014 to 2016 period. We prepared analyses of the following ratemaking approaches:

Rate Option 1: I-X revenue per customer adjustment mechanism
Rate Option 2: General Purpose Capital Tracker, combined with an I-X revenue per customer adjustment mechanism
Rate Option 3: Special Project Capital Tracker, combined with an I-X revenue per customer adjustment mechanism
Rate Option 4: Customized IR (EGD's Proposed Approach)

It is Concentric's assessment that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $141.5 million. An I-X escalation formula combined with a general purpose capital tracker mechanism also does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $88.2 million. Further, an I-X escalation formula combined with a special project capital tracker for the GTA and Ottawa reinforcement projects does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $51.2 million. Only Rate Option 4, a Customized IR plan with recovery of capital-related costs matched to EGD's projected capital-related revenue requirements adequately covers the costs of EGD's base capital spending and GTA and Ottawa reinforcement projects.

EGD also asked Concentric to review EGD's proposed earnings sharing mechanism ("ESM") and provide our perspective regarding the reasonableness of EGD's proposed ESM, given the overall structure of EGD's proposed program. Concentric understands that EGD is proposing an ESM with a deadband of 100 basis points above the authorized ROE, with a 50/50 sharing formula and a +/-300 basis point review trigger, the same as that approved for EGD's 1st Generation IR Plan. On balance, we conclude that EGD's proposed ESM provides an appropriate safeguard for customers and the utility, while continuing to provide ongoing incentives for productivity improvement. The deadband serves the purpose of incenting EGD to identify additional efficiencies, while the earnings sharing and re-opener trigger provide a safety mechanism to address large deviations in earnings. While we could argue that a 100 basis point deadband creates a diminished incentive compared to a wider deadband, and that a symmetrical ESM would better balance the risk and reward profiles of EGD and customers, EGD's performance under the 1st Generation IR (with the same ESM parameters) suggests that these issues are manageable, as customers benefited from earnings sharing in all 5 years of the Plan. Based on our research and industry experience, Concentric believes that EGD's ESM proposal is reasonable.

To evaluate EGD's proposed Customized IR plan as a whole, Concentric contrasted the total revenue recovered under two alternative rate recovery alternatives (I-X, and I-X plus Y factors for the GTA and Ottawa projects) versus Enbridge's projected O&M and capital related costs over the 2014 to 2016 period. The I-X rate option leads to a three-year cumulative shortfall of $126 million; the I-X plus Y factor option produces a deficiency of $35.7 million that also does not provide for adequate recovery of the Company's projected costs, even with accounting for embedded improvements in efficiency from 2014 to 2016.

Based on our analysis, research and industry experience, Concentric believes that EGD's overall proposed Customized IR proposal is reasonable. The proposed IR approach is the only mechanism evaluated that allows the Company the opportunity to recover its costs (including the larger than normal capital investment), while providing Enbridge with a built-in challenge for continued productivity improvement. On balance, we conclude that EGD's proposed Customized IR plan provides an appropriate safeguard for customers and the utility, and meets to Board's goals for incentive regulation while allowing the Company a reasonable opportunity to earn a fair return.

II. INTRODUCTION

A. Overview

Enbridge retained Concentric to provide analytical, research and regulatory support related to the Company's proposed 2nd Generation Incentive Regulation ("IR") Plan, which the Company is referring to as a "Customized IR" plan. Based on a combination of research, analysis and knowledge of North American incentive regulation programs, Concentric was asked to:

- Assess relevant regulatory precedents in Ontario and other North American jurisdictions pertaining to IR plans
- Research productivity factors and methods established in other jurisdictions for estimating utility productivity
- Evaluate the productivity factor approach taken by Pacific Economics Group (retained by the Board in EGD's last IR case)
- Estimate productivity factors for EGD and a study group and interpret the results and observed differences between EGD and comparators; this task included the following sub-tasks:
    - Determine the appropriate study group, data measures and timeframe for productivity analysis for EGD
    - Evaluate appropriate measures of inflation
    - Consider data limitations and issues
    - Consider costs that should be excluded because they are outside of EGD's control
    - Consider events or circumstances that should be isolated broadly or for specific companies
    - Consider any US vs. Canadian company differences
    - Evaluate the results over the historic time period in relation to Enbridge's current and anticipated operating environment
    - Compare the results to other studies
- Evaluate the appropriateness of a consumer dividend or "stretch" factor
- Benchmark Enbridge against Canadian and U.S. peers across a series of operating and cost measures.[3]

This scope evolved as Concentric's work progressed, and as Enbridge evaluated the implications for its 2nd Generation IR plan. The conclusion was ultimately reached that a traditional "I-X" framework would be challenged by Enbridge's operating circumstances over

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[3] Concentric Proposal for Consulting Services to Enbridge, December 8, 2010.

the next plan period. The Company's capital investment plans, in particular, do not fit within a "steady state" incentive regulation framework. Concentric was asked to evaluate the Company's capital spending plans, research alternative frameworks incorporating capital spending, and quantify the outcomes vis-à-vis alternative recovery mechanisms to assess the reasonableness of these approaches.

Consistent with the Ontario Energy Board's ("OEB", or the "Board") rules for expert evidence,[4] this report provides Concentric's analysis and recommendations resulting from the scope of work defined above, designed to assist the Board's deliberations on this matter. The report is divided into the following sections: the remainder of Section II provides an overview of EGD's existing IR plan; Section III summarizes EGD's proposed Customized IR framework; Section IV discusses Concentric's evaluation of EGD's productivity; Section V discusses Concentric's I Factor analysis; Section VI contains Concentric's evaluation of EGD's treatment of O&M; Section VII discusses Concentric's analysis regarding EGD's treatment of capital; Section VIII contains a discussion regarding EGD's proposed ESM; and Section IX contains an evaluation of EGD's Customized IR plan.

B. Enbridge's 2008-2012 IR Plan

Enbridge's 1st Generation IR plan (2008-2012) is the product of a settlement agreement approved by the Ontario Energy Board ("OEB" or "the Board") on February 10, 2008 in EB-2007-0615. According to the settlement agreement, Enbridge's annual distribution revenue requirement is determined by a formula that provides for increases in revenue per customer at a fixed percent[5] of annual inflation as measured by an inflation index published by Statistics Canada.[6] The approved settlement agreement also provides for recovery of specific categories of costs (Y-factor costs) on a cost of service basis and certain exogenous costs (Z-factor costs). The Distribution Revenue Requirement per Customer Formula ("Adjustment Formula") is described below:

Adjustment Formula

$$\mathbf{DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * INF) * C_t + Y_t + Z_t}$$

Where:

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4 The OEB Rules of Practice and Procedure, Rule 13A, Expert Evidence.

5 The fixed percent ranges from 60 percent in 2008 to 45 percent in 2012.

6 The fixed percent of annual inflation is represented in the adjustment formula as: P * INF, which is comparable to the "I-X" formula frequently used. The P * INF formula represents an adjustment based on a percent of inflation, while the I-X formula represents an adjustment based on a fixed deduction from inflation.

DRR_t = The distribution revenue requirement in year t

t = The rate year

C = The average number of customers

P = The inflation coefficient

INF = The inflation index, measured as the actual year-over-year change in the annualized average of four quarters (using Q2 to Q1) of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP-IPI-FDD"), adjusted annually with no true-ups.

Y = Pass-throughs at cost of service (including DSM costs; CIS/customer care costs; upstream gas costs; upstream transportation, storage and supply mix costs; and changes in the embedded carrying cost of gas in storage and working cash related to changes in gas costs; capital expenditures related to power generation projects).

Z = Exogenous factors (meeting a materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event)).

The inflation coefficient ("P") and the implied X factor varied by year, as shown in Figure 2.

Figure 2: Inflation Coefficient over the Plan Term

Year	**Inflation Coefficient (P)**	**Implied X Factor (X) (as % GDP IPI FDD)**
2008	.60	40%
2009	.55	45%
2010	.55	45%
2011	.50	50%
2012	.45	55%

If actual ROE exceeded approved ROE by more than 100 basis points, the resultant amount was shared equally between Enbridge and its ratepayers. If actual ROE differed from approved ROE by more than 300 basis points, Enbridge was required to file an application for a review of the Adjustment Formula. The rate of return on equity ("ROE") of 8.39% that was already included in the Company's rates for 2007 was held constant over the IR period for setting rates, but earnings sharing was calculated based on the ROE Formula during the term of the IR Plan.

C. Challenges for the 2nd Generation Plan

In Concentric's view, incentive regulation programs should both serve the objectives of the regulator and stakeholders (including shareholders), while recognizing the specific operating circumstances of the utilities under the program. It is our understanding that stakeholders were generally satisfied with Enbridge's 1st Generation IR Plan, as was the Company, suggesting a balance of interests achieved in the end result.[7]

EGD and Concentric conducted a series of studies and analyses to test different structures for the Company's 2nd Generation IR Plan that would meet the following criteria specified in the Company's evidence, taken from the Board's Natural Gas Forum and the Ontario Energy Board Act:

a) Ensure appropriate reliability and quality of service (including safe operations);
b) Protect customers from unreasonable price impacts;
c) Promote energy conservation and efficiency;
d) Protect the financial viability of the distributor and allow for appropriate investments to be made; and
e) Provide a framework that incents the distributor to implement sustainable efficiency improvements.

Concentric developed an X Factor, based on a TFP study, which could be used in an I-X adjustment formula to determine an appropriate rate path for a productive utility, incenting further gains in productivity for the benefit of both customers and shareholders. Enbridge then prepared a forecast of costs, based on preliminary O&M and capital budgets. EGD also prepared a revenue forecast, based on Concentric's estimated X factor. At the conclusion of this preliminary analysis, it became evident to EGD that the 2nd Generation IR plan would have to be substantially different from the 1st Generation plan to account for Enbridge's O&M and Capital budgets for 2014 and beyond.

The single greatest challenge for Enbridge under a continued I-X framework would be accommodating the Company's capital spending plans, detailed later in this report and in the Company's B2 series of exhibits. The combination of the Greater Toronto Area ("GTA") and Ottawa Reinforcement projects and Work and Asset Management System ("WAMS") project in conjunction with elevated safety and reliability investment would lead to a substantial

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7 Based on discussions with the Company and comments made during the initial stakeholder conference to discuss the next generation IR plan on December 7, 2012.

under-recovery of costs without an adjustment to a traditional I-X IR plan. This problem challenges the implicit assumption behind a steady state I-X rate path, as has been recognized by regulators elsewhere.

The OEB's Renewed Regulatory Framework ("RRF") for Electricity (October 18, 2012) recognized that an I-X IR plan may not be appropriate for all electric distributors:

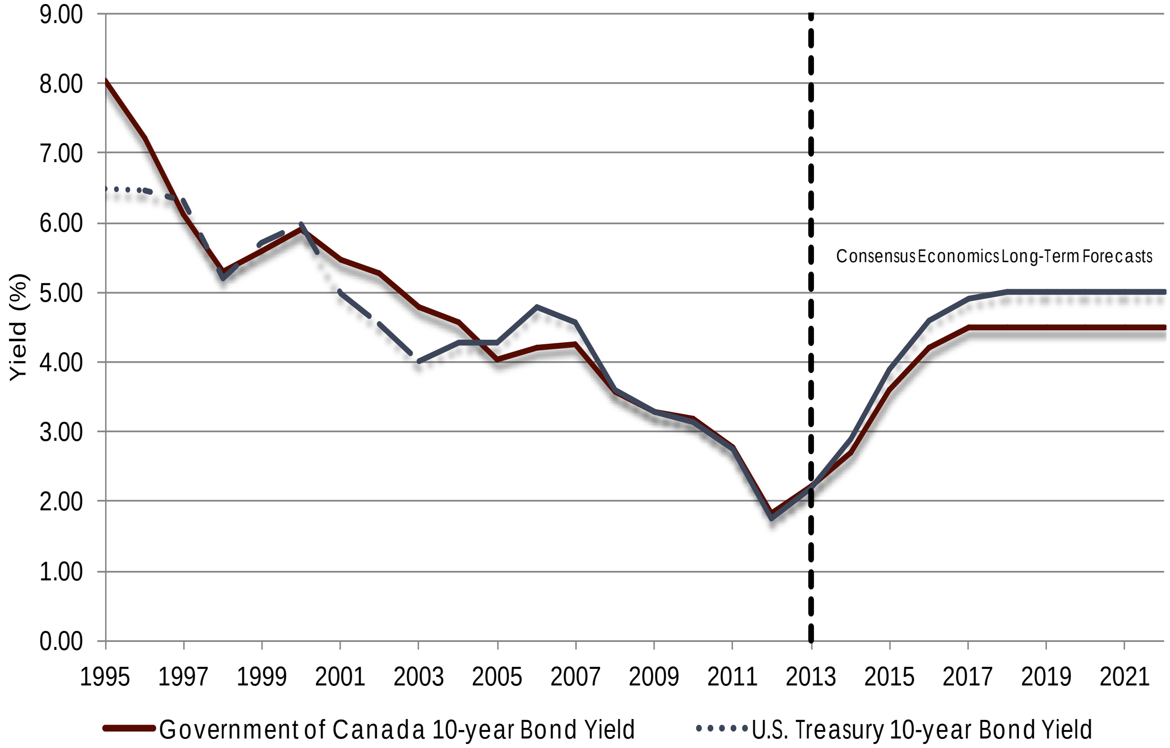
> Three alternative rate-setting methods will be available to distributors.
>
> Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. This will provide greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include "lumpy" investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.[8]

Concentric's analysis of Enbridge's capital spending plans leads to the conclusion that, as envisioned for certain electric distributors, a "lumpy" and higher than normal capital spending path would not be sufficiently recovered under a traditional I-X framework. A related issue for Enbridge is a high degree of uncertainty associated with future capital spending requirements, especially beyond a three-year timeframe.

Another challenge to earning a fair return that Enbridge faces during the term of the 2nd Generation IR plan is the uncertain but likely upward path of future interest rates. This issue is not unique to Enbridge, but companies, such as Enbridge, with larger than average capital spending have greater exposure to risk from rising interest rates. The consensus view as compiled by Consensus Economics is that interest rates will rise steadily over the rate plan, but the path will depend on a host of macroeconomic and policy factors well outside the Company's control. Figure 3 depicts the consensus view.

[8] Report of the Board, Renewed Regulatory Framework for Electricity, October 18, 2012, pp. 9-10.

Figure 3: 10 Year Government Bond Yield Projections



Source: Bloomberg Professional and Consensus Economics Inc.

While any utility operating under an I-X rate plan without an explicit adjustment mechanism would bear the risk of interest rate changes beyond the I-X rate path, utilities with higher-than-normal capital spending during periods of rising interest rates incur greater risk as new equity and debt financing occurs at prevailing market rates. Other risks for the Company in the 2nd Generation IR plan include uncertainty regarding system growth and its impacts on labor and other O&M costs, changes in tax rates, and the scope of certain capital projects (e.g., AMP fittings). These risks will remain with the Company under its proposed Customized IR plan.

III. PROPOSED INCENTIVE REGULATION FRAMEWORK

A. Incentive Regulation Overview

All forms of utility regulation generally include incentives, either explicitly or implicitly. Traditional cost of service ("COS") regulation includes implicit incentives to lower costs below those approved in rates to the benefit of the utility and its shareholders, and conversely costs above those in rates are absorbed by the utility to the benefit of customers. For the past several decades, regulators in North America, Europe and elsewhere have attempted to improve on these basic principles with more explicit incentive frameworks, broadly characterized as Incentive Regulation ("IR"). In doing so, regulators have sought to overcome some of the perceived shortcomings of COS regulation, such as frequent rate hearings, the inability to assess productivity and efficiency, the asymmetry of information between the utility, regulatory staff and stakeholders, and the lack of strong incentives for continuous productivity improvement.

A variety of IR frameworks have been implemented over the past two decades in the U.S. and Canada.[9] Four basic approaches have been utilized:

- Multi-year "fixed" rate plan (or "rate freeze")[10]
  - Rates are fixed over the plan period
  - Some allowances for costs beyond utility control
  - Primarily used to lock-in consumer benefit following a merger
- I-X plan[11]
  - Rate or revenue per customer escalates with inflation (I)
  - Productivity gain (X) locked in for customers
  - Some allowances for costs beyond utility control
- Targeted rate adjustment mechanisms[12]

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[9] IR plans have also been implemented in the U.K. and Australia, as described in the evidence of London Economics, International.

[10] See, for example, National Grid merger with Niagara Mohawk and the 10 year rate program approved for Niagara Mohawk's electric customers. NYPSC CASE 01-M-0075, December 3, 2001, and also the 5 year rate plan approved for the National Grid merger with Keyspan Corporation, NYPSC Case 06-M-0878, September 17, 2007.

[11] See, for example, programs adopted in Ontario, California, Massachusetts, Maine, and Vermont.

[12] See, for example, Bay State Gas Company, d/b/a Columbia Gas of Massachusetts ("CMA") where the DPU approved a cost recovery mechanism for CMA's replacement program for bare and unprotected steel infrastructure, D.P.U. 12-25 November 1, 2012; and New Jersey Board of Public Utilities Decision and

  - Tracks the costs of specific categories of O&M expenses or capital spending between rate cases
- Building Block Ratemaking[13]
  - "Building block" approach to forecast revenue
  - Productivity built into operating and capital cost projections

As a general premise, the goals of such programs have been to mitigate the aforementioned shortcomings of COS regulation, or to address specific circumstances.[14] In our experience, these programs are typically initiated with significant input from stakeholders and utilities. In recent years, we have observed a trend away from the first two types of programs toward more traditional COS approaches, targeted plans, or the building block approach. We believe this shift has been attributable to several factors: the reluctance of utilities to lock into fixed rate programs in the face of uncertain or rising costs and moderating or declining demand; the challenges associated with reliably estimating industry productivity and applying an I-X framework with many moving cost and revenue drivers; recognition by regulators and stakeholders that utilities have limited control over some cost factors, and more control over others; and the desire to target specific program areas of heightened importance (e.g., system reliability, customer satisfaction, demand side management, large capital project spending). In jurisdictions with ongoing IR frameworks, such as Ontario and California, these factors have led to revisions to previous generation plans.[15]

B. Overview of EGD's Proposed IR Framework

Enbridge is proposing a "Customized IR" plan, with features similar to those described in the OEB's Renewed Regulatory Framework ("RRF") for Electricity (October 18, 2012) and the "building blocks" approach utilized in California, the U.K. and Australia. This Customized IR plan has differences from EGD's prior plan in that it moves to an annual Revenue Cap determined from forecast costs. With this approach, both capital and O&M costs are based

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Order Approving Stipulations, 4/28/2009, for South Jersey Gas which approved a capital investment recovery tracker.

13 See for example, programs adopted in California for SoCal Gas in proceedings AP-10-12-006), SDG&E in AP-10-12-005, and for PG&E in AP05-12-002 D07-03-044, and those adopted in the U.K. and Australia.

14 For example, in a proceeding in which two utilities are seeking regulatory approval to merge, the regulators may require that the utility would be prohibited from filing a rate case for a specified period in order to guarantee a customer benefit from the merger.

15 See, for example, the Ontario Energy Board, "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach," October 18, 2012.

on “bottom-up” projections, aggregated to produce total revenue. Productivity is embedded in these forecasts, derived from management scrutiny of the bottom-up budgets.

Concentric has evaluated the Enbridge’s proposed Customized IR plan based on our regulatory and industry research, quantitative analysis, and knowledge of other programs in North America. We have assessed Enbridge’s proposed Customized IR plan from two primary perspectives:

- Consistency with Ontario and North American regulatory principles and practice;
- Quantitative assessment of Enbridge’s operational efficiency and projected revenue vs. I-X rate paths.

IV. <u>EVALUATION OF EGD'S PRODUCTIVITY</u>

A. Introduction

EGD asked Concentric to provide a perspective on the level of Enbridge's costs and productivity relative to its industry peers. In order to provide this perspective, Concentric conducted an industry cost benchmarking study as well as an industry productivity study.

<u>Benchmarking</u> is a commonly employed and intuitive technique used across a wide variety of industries that compares a company's performance metrics against an industry group, which serves as the benchmark. Comparator companies are typically chosen from within the same industry, and screens are applied to narrow the field to companies with reasonably comparable operating and business conditions. For utilities, the performance metrics often include measures of cost and factors that affect cost; benchmarking metrics are typically normalized around common factors, such as number of customers, to compare the relative performance of the benchmark companies. Company size, geography, age of assets, are examples of measures that may be used in distribution utility benchmarking analyses as screens to select companies for the study, or as variables included in the analysis to explain performance differences. A Benchmarking study may be conducted for a single year or a limited number of years. Although no two companies face identical operating and business conditions, benchmarking provides a reasonable basis for company management, regulators and stakeholders to assess performance, identify best practices and to estimate performance gaps. In this case, benchmarking provides perspective on EGD's current efficiency versus its peers, which sets the state for evaluating future productivity expectations. In general, more efficient companies find incremental gains more challenging than those starting at a lower level of efficiency.

<u>Productivity</u> studies are used to measure a firm's effectiveness in converting its factors of production – inputs (typically measured by labour, materials and/or capital) into outputs (typically measured in physical units). Productivity analysis can be applied to single firms, whole industries or the broader economy and can be used to compare the productivity of a single firm with the productivity of the industry. The impacts of changes in the prices of inputs are controlled for to focus on measuring the productive efficiency of the economic unit, e.g. firm, industry, or economy, in converting inputs into outputs. Indexing methods are used to estimate these productivity relationships, derived from data across one or more economic units over time, and compared between different economic units. Productivity analysis has been used in several US and Canadian regulatory jurisdictions to measure utility productivity or to develop indexing mechanisms for IR plans. While the theory behind

productivity is well established, model estimation is not without its challenges or controversy. Data availability is also a significant issue.

The balance of Section IV includes (a) a description of the process that Concentric used to select the companies in the industry study group; (b) a summary of Concentric's benchmarking analysis; and (c) a summary of Concentric's productivity analysis.

B. Selection of Industry Study Group

Common to both the industry benchmarking and productivity analyses performed by Concentric is the need to develop an industry study group of companies that are representative of EGD's operating circumstances. Concentric developed criteria to identify companies that are similar to EGD while allowing for a sufficient number of companies in the study group to ensure that the analyses would be robust and provide an appropriate perspective for industry comparisons. Although the same criteria were used to develop the industry study group for the benchmarking and productivity analyses, the productivity analysis industry study group has fewer companies. Some companies in the benchmarking study group were excluded from the productivity analysis due to data limitations.[16]

The companies in the industry study group were determined according to the following criteria:

- Similarity of operations to EGD - the companies in the industry study group are natural gas distribution utilities; the gas distribution company of a combination utility was included if data for natural gas distribution operations were available separately from electric operations;
- Similarity of weather conditions to EGD - the companies in the industry study group are (a) located in one of the states in the northern half of the continental U.S. and have average annual state heating degree days within +/- 45% EGD's service territory,[17] or (b) located in Canada;

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[16] For example, the productivity analysis study group does not include any Canadian companies because there is no centralized source that contains the detailed historical data necessary for productivity analysis, but Canadian companies were included in a limited fashion in the benchmarking analysis.

[17] Based on analysis of annual HDD data from 2006 to 2011 for the U.S. states and Enbridge's service territory. Thirty-three states passed the weather screen.

- Similarity of size to EGD as measured by number of customers - the companies in the industry study group have at least 500,000 customers within a single state[18] or at least 150,000 customers within a single province;[19] and,
- Data availability - the necessary data for the companies in the industry study group are available in published or subscription service reports or databases.[20]

These criteria resulted in an Industry Study Group of 28 U.S. natural gas utilities comprised of 48 individual operating subsidiaries, and 6 Canadian natural gas utilities.[21] A subset of 25 U.S. natural gas utilities and 42 operating subsidiaries was used in the productivity analysis; Canadian gas utilities and three U.S. gas utilities were not included in the productivity analysis due to data limitations. The following table lists the companies that are included in the Industry Study Group.

18 Data for multiple operating subsidiaries of a single parent company within a state were aggregated; for example, the three operating subsidiaries of National Grid (NY) were aggregated into a single company for the purposes of our analysis.

19 The Canadian customer threshold was lowered compared to the U.S. customer threshold due to the limited universe of Canadian natural gas utilities.

20 There are a host of issues associated with building a database of this magnitude containing historical operational and cost data for many companies. Concentric has managed these issues with proxy group selection, data screening for outliers, filling in missing data where possible, and eliminating companies where data was insufficient. Please see Appendix B, Section I for more detail about data sources and database development.

21 Due to challenges associated with compiling data for Canadian utilities, only data for 2009 was obtained.

Figure 4: Industry Study Group Companies

	Industry Study Group Companies	Primary State[22]/ Province	Operating Subsidiaries	
Used in Benchmarking and Productivity Analyses				
1	Ameren Corporation (Ameren IL)	IL	Central Illinois Light Company	1
			Central Illinois Public Service Company	2
			Illinois Power Company	3
2	CenterPoint Energy Resources Corp. (CenterPoint MN)	MN	CenterPoint Energy Resources Corp.	4
3	Consumers Energy Company (Consumers MI)	MI	Consumers Energy Company	5
4	Consolidated Edison, Inc. (ConED NY)	NY	Consolidated Edison Company of New York, Inc.	6
			Orange and Rockland Utilities, Inc.	7
5	Baltimore Gas and Electric Company (BG&E MD)	MD	Baltimore Gas and Electric Company	8
6	Dominion - East Ohio Gas Company (Dominion OH)	OH	East Ohio Gas Company	9
			West Ohio Gas Company	10
7	DTE Energy Company (DTE MI)	MI	Michigan Consolidated Gas Company	11
			Citizens Gas Fuel Company	12
8	Iberdrola, S.A. (Iberdrola NY)	NY	Rochester Gas and Electric Corp	13
			New York State Electric & Gas Corp	14
9	Integrys Energy Group, Inc. (Integrys IL)	IL	North Shore Gas Company	15
			Peoples Gas Light and Coke Company	16
10	Laclede Gas Company (Laclede MO)	MO	Laclede Gas Company	17
11	National Fuel Gas Distribution (National Fuel NY)	NY	National Fuel Gas Distribution Corporation	18
12	National Grid (National Grid MA)	MA	Boston Gas Company	19
			Colonial Gas Company	20
			Essex Gas Company	21
13	National Grid (National Grid NY)	NY	KeySpan Energy Delivery (formerly Brooklyn Union)	22
			KeySpan Gas East (formerly Long Island Lighting)	23
			Niagara Mohawk Power Corporation	24
14	Northern Illinois Gas Company (Nicor IL)	IL	Northern Illinois Gas Company	25
15	Columbia Gas Of Ohio (Columbia OH)	OH	Columbia Gas Of Ohio, Inc.	26

22 For a limited number of Industry Study Group Companies, data from another state were included if the "secondary state" operations were a small percent of the total company operations and if the "secondary state" data was not reported separately from the primary state data.

	Industry Study Group Companies	Primary State[22]/ Province	Operating Subsidiaries	
16	NiSource Inc. (NiSource IN)	IN	Northern Indiana Fuel & Light Company, Inc.	27
			Northern Indiana Public Service Co.	28
			Kokomo Gas And Fuel Company	29
17	Northwest Natural Gas Company (NWN OR)	OR	Northwest Natural Gas Company	30
18	Public Service Electric and Gas Company (PSE&G NJ)	NJ	Public Service Electric and Gas Company	31
19	Puget Sound Energy, Inc. (Puget WA)	WA	Puget Sound Energy, Inc.	32
20	Questar Gas Company (Questar UT)	UT	Questar Gas Company (Formerly Mountain Fuel Gas)	33
21	Southern Union Company (MGE MO)	MO	Missouri Gas Energy	34
22	Vectren Corporation (Vectren IN)	IN	Indiana Gas Company, Inc.	35
			Southern Indiana Gas and Electric Company, Inc.	36
23	Washington Gas Light Company (WGL DC,MD,VA)	DC,MD, VA	Washington Gas Light Company	37
			Shenandoah Gas Company	38
24	Wisconsin Energy Corporation (WE WI)	WI	Wisconsin Natural Gas Company	39
			Wisconsin Electric Power Company	40
			Wisconsin Gas LLC	41
25	Public Service Company of Colorado (PSCO CO)	CO	Public Service Company of Colorado	42
Used in Benchmarking Analysis, but Excluded from Productivity Analysis				
26	MidAmerican Energy Company (MidAmerican IA)	IA	MidAmerican Energy Company	43
27	Philadelphia Gas Works Company (PGW PA)	PA	Philadelphia Gas Works Company	44
28	UGI Utilities, Inc. (UGI PA)	PA	UGI Utilities, Inc.	45
			UGI Penn Natural Gas, Inc.	46
			UGI Central Penn Gas, Inc. (PA)	47
			UGI Central Penn Gas, Inc. (MD)	48
29	ATCO	AB	ATCO	49
30	FortisBC	BC	FortisBC	50
31	Gaz Metro	QC	Gaz Metro	51
32	Manitoba Hydro	MB	Manitoba Hydro	52
33	SaskEnergy Inc.	SK	SaskEnergy Inc.	53
34	Union Gas Limited	ON	Union Gas Limited	54

C. Benchmarking Analysis

Concentric conducted a cost benchmarking analysis, which measures EGD's performance against the industry study group using a series of metrics that quantify the relative efficiency of EGD in terms of both its capital investment and O&M expense profile. This benchmarking analysis is an update to a benchmarking study that was submitted in EGD's 2013 rebasing case. This update relies on the same methodology, data sources, and U.S. industry study group as the original benchmarking study, but now incorporates 2011 data. Canadian companies were included in the original benchmarking analysis for 2009; however, due to the difficulty obtaining consistent, reliable data, Canadian companies were not included in the 2011 update.

Data for EGD was provided by the Company. Data for the U.S. industry study group was primarily compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports"). A summary of the 2011 benchmarking update is presented below; detailed results for the 2011 benchmarking update can be found in Appendix A. The original benchmarking study was submitted in EGD's rebasing case, EB-2011-0354, Exhibit A2, Tab 1, schedule 2.

To provide context and background, EGD's 2011 operational profile was compared with the peer group companies using the following metrics:

- Number of customers
- Residential customers as a percent of total customers
- System throughput
- Residential volumes as a percent of total delivery volumes
- Average natural gas use per customer
- Customers per kilometer of main
- Delivery volumes per kilometer of main.

Results for 2011 number of customers and customers per kilometer of main are provided in Figures 5 and 6. Results for all metrics are presented in Appendix A.

Figure 5: Total 2011 Natural Gas Customers

(Sales and Transportation, excludes Resale Customers)

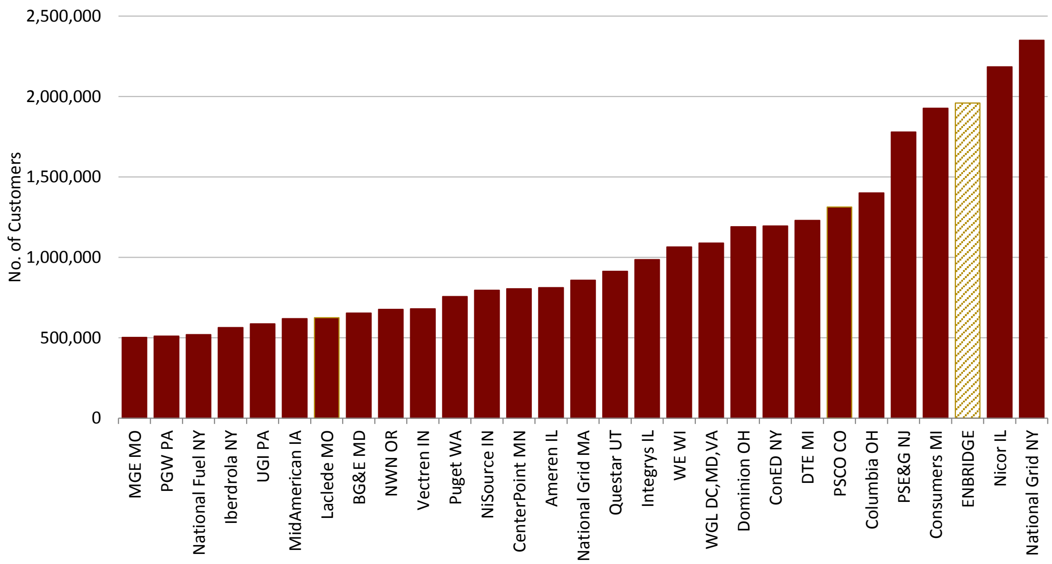
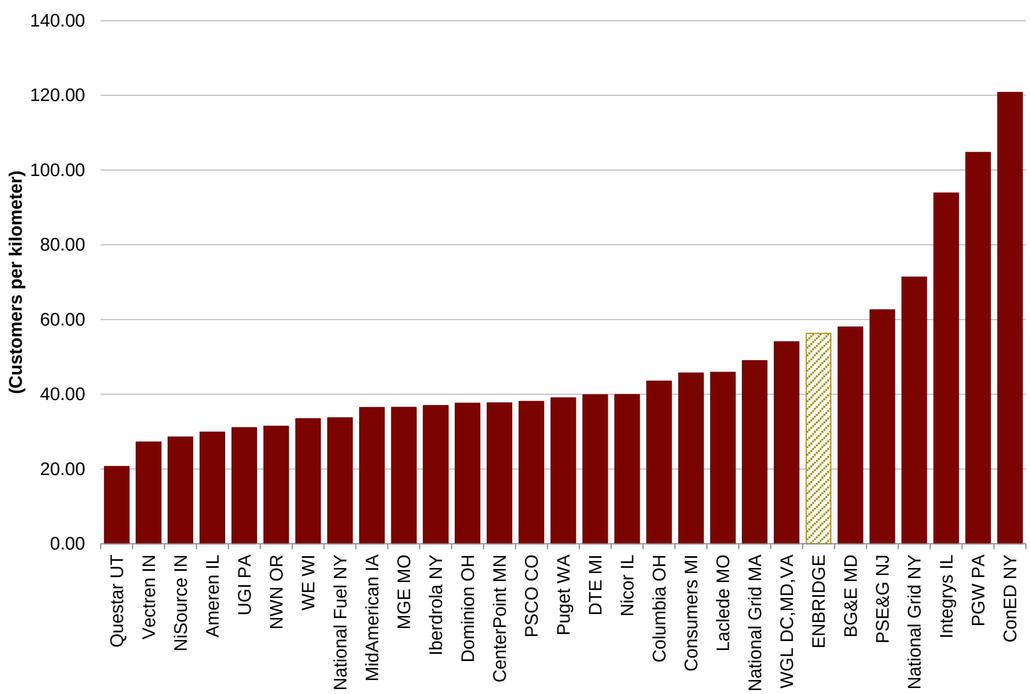


Figure 6: 2011 Natural Gas Customers per Kilometer of Distribution Main



The operational profile analysis indicates that EGD is one of the largest and most dense utilities in the industry study group. EGD had the third largest customer count and volume in 2011. In addition, EGD is in the highest quartile for 2011 use per customer and density.[23]

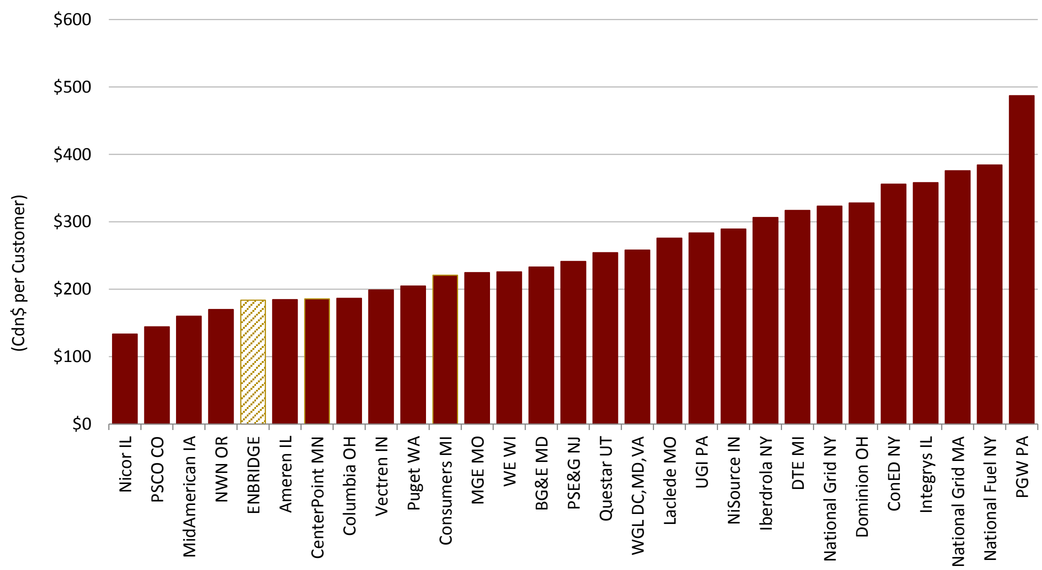
EGD's cost performance was benchmarked against the individual companies in the industry study group for 2011 and EGD's performance trends over the 2000 to 2011 time period were compared against the industry study group average using the following metrics:

- Net plant per customer and per unit of volume
- O&M expenses per customer and per unit of volume
- Labour costs per customer and per employee (both including and excluding capitalized labour)
- Customers per employee

Results for 2011 O&M cost per customer and net plant per customer are presented in Figures 7 and 8. Results for all metrics are presented in Appendix A.

Figure 7: Total 2011 Gas O&M Expenses per Customer

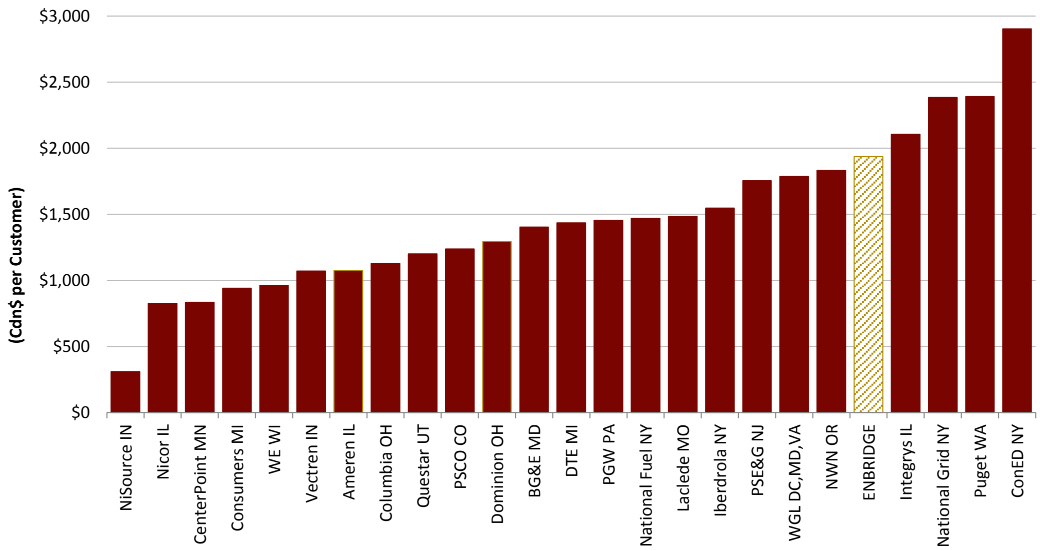
(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



23 Results for use per customer and density are included in Appendix A.

Figure 8: Total 2011 Net Plant per Customer

(Includes Transmission, Storage, Distribution and Allocated General Plant)[24]



EGD's 2011 O&M costs per customer, O&M costs per unit of volume, customers per employee, and labour cost per customer (excluding capitalized amounts) are within the lowest – best - quartile. In addition, EGD's 2011 net plant per volume, labour cost per customer (including capitalized amounts), and labour cost per employee are at or below the median of the industry study group. EGD's position in the top quartile of the total net plant per customer metric (EGD's net plant per customer ranking is fifth highest out of 25 companies) may appear to be inconsistent with its position in the top quartile of the customers per kilometer of distribution main (i.e. EGD's customers per kilometer ranking is seventh). However, there are other companies with similarly high plant per customer rankings and customers per kilometer of distribution rankings: ConEd, Integrys, National Grid NY and WGL. Because these LDCs serve large urban areas, it appears that the high cost of installing mains in these large urban areas may more than offset the economies of scale associated with high rankings on the customers per kilometer of main metric.

In addition to comparing EGD's 2011 cost performance to the industry study group, Concentric also compared EGD's cost trends to the industry study group average over the 2000 to 2011 time frame for the same metrics. Results for O&M cost per customer and net plant per customer are presented in the following figures. Results for all metrics are presented in Appendix A.

24 Some companies were excluded from the net plant metrics due to data limitations.

Figure 9: Total Gas O&M Expenses per Customer[25]

(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)

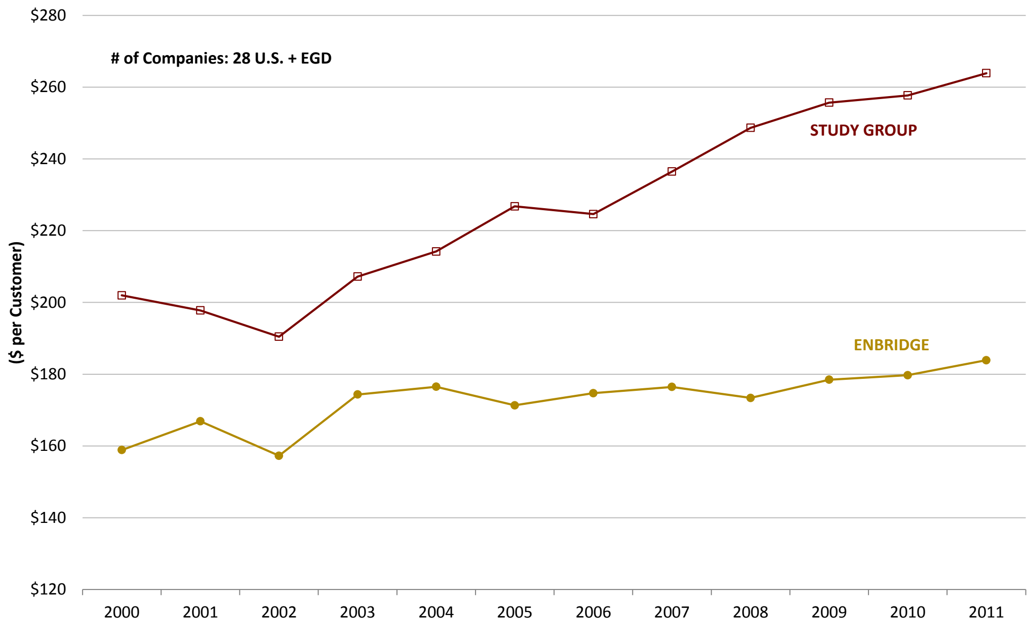


Figure 10: Total Net Plant per Customer

(Includes Transmission, Storage, Distribution, and Allocated General Plant)

25 The line charts, which compare costs over the entire 2000 to 2011 period, are expressed in own-country US and Canadian dollars for both the study group and Enbridge, which avoids issues associated with year-to-year exchange rate differences.

Regarding trends in EGD's cost performance relative to the industry study group over the 2000 to 2011 period, Enbridge has generally sustained or improved its cost position in relation to its peers, including during the most recent IR plan period. Although EGD's 2011 net plant per customer costs are above the study group average, the industry study group net plant per customer has been rising at a faster rate (3.00%) than EGD's (0.93%) over the 2000 to 2011 period.

Results from Concentric's cost benchmarking analyses indicate that EGD is among the most efficient of its industry peers, especially related to O&M and labour costs, although EGD's net plant costs per customer are high compared to the industry study group. This suggests that it may become progressively more difficult for EGD to find additional efficiencies going forward.

D. Productivity Analysis

1. Productivity Analysis Introduction

As discussed in Section IV.A, productivity analysis measures a firm's effectiveness in converting its factors of production into output, which can be measured in physical terms. Concentric conducted productivity analyses for EGD and the industry study group to allow for a comparison.

Productivity is generally specified as the difference between output growth and input growth:

Productivity Growth = Output Quantity Growth – Input Quantity Growth

A productivity index is calculated from annual changes in productivity. The productivity analysis measures total factor productivity ("TFP") if input quantity growth is measured by all inputs to the firm (i.e., capital, labour, and materials). The productivity analysis measures partial factor productivity ("PFP") if input quantity growth is measured by a subset of the inputs (e.g., labour and materials). For this study, Concentric prepared separate TFP and PFP indexes for EGD and for the industry study group. While the data sources were necessarily different for the EGD and industry study group productivity analyses, the methodology was the same.

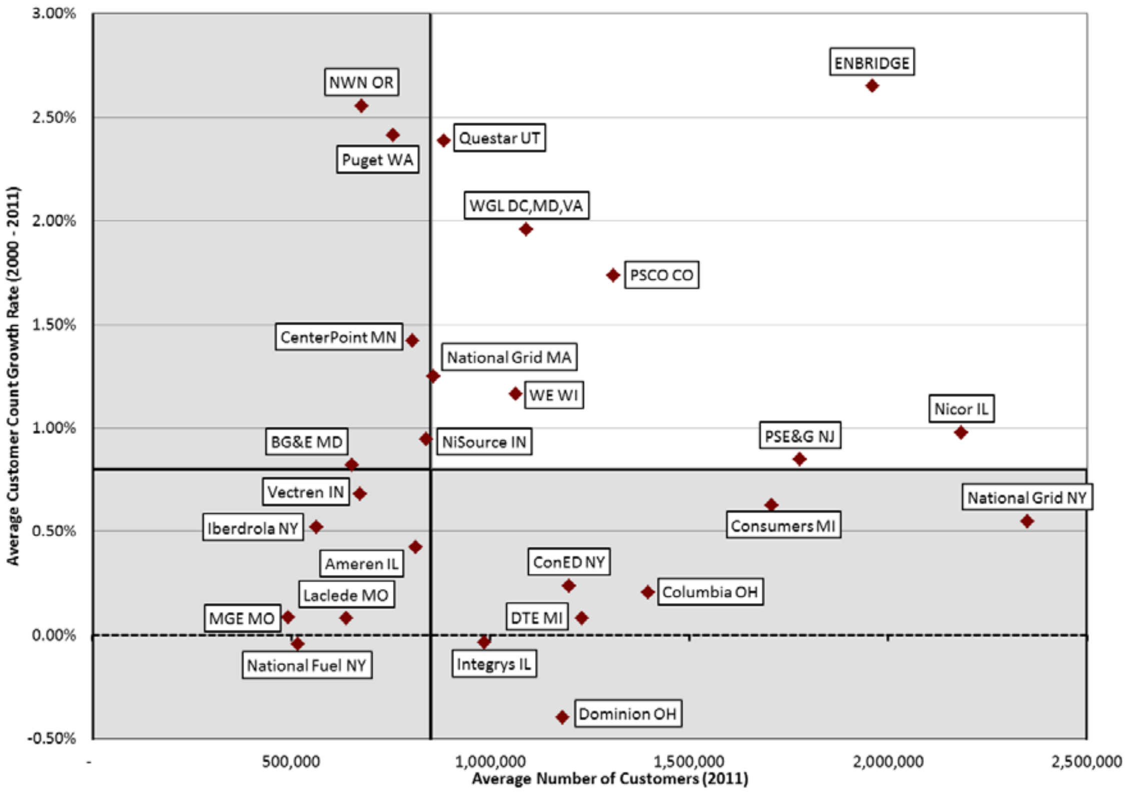
2. Determination of the Industry Study Group and Sub-Group

The industry study group used for the productivity analyses is the same as that used for the benchmarking analysis, with a few exceptions. The industry study group used in the productivity analyses consisted of 25 U.S. natural gas utilities. Canadian utilities,[26] MidAmerican, Philadelphia Gas Works and UGI were not included in the productivity analyses because the required data was not available.

In order for the productivity analysis to reasonably compare the target company – EGD – with other companies, the industry sample group should be similar to the target company as measured by factors that affect gas distribution cost structures. Because EGD is larger and has experienced higher customer growth rates in recent years than many of the 25 companies in the industry study group, Concentric developed a sub-group for the productivity analyses by applying more restrictive size and customer growth criteria to the 25 industry study group companies. Figure 11 provides a graphical representation of the more restrictive criteria. Each of the 25 industry study group companies plus EGD are represented on the scatter plot; the size of company, as measured by 2011 customer count, is reflected on the (horizontal) X-axis, and the 2000 to 2011 customer growth rate for each company is reflected on the (vertical) Y-axis. As shown in Figure 11, the customer counts for the 25 companies plus EGD range from approximately 500,000 to over 2.3 million. Only two companies in the industry study group have more customers than EGD's 1.9 million customers. As also shown in Figure 11, the 2000 to 2011 customer growth rates for the 25 companies plus EGD range from -0.4% to over 2.6%. EGD's customer growth rate, 2.6%, is higher than all other companies in the industry study group.

[26] Except EGD.

Figure 11 Customer Count and Customer Growth Rates



Based on these considerations, Concentric determined that a sub-group of companies with at least 850,000 customers in 2011, and at least 0.8% customer growth over 2000 to 2011 would result in a sub-group that is more representative of EGD and of sufficient size to provide meaningful results. The sub-group, which is represented in the top right-hand quadrant in the scatter plot (shaded white), consists of seven companies: Northern Illinois Gas Company, Public Service Electric and Gas Company, Questar Gas Company, Public Service Company of Colorado, National Grid (MA), Washington Gas Light Company, and WE Energies. Altogether, Concentric conducted TFP and PFP analyses for (a) the seven company sub-group, (b) the 25 company industry study group, and (c) EGD.

Concentric's company-specific TFP and PFP indexes for EGD and for each of the companies in the industry study group (and the seven company sub-group) are based on company-specific Input Indexes and Output Indexes. Concentric developed TFP and PFP indexes for the industry study group and the seven company sub-group by weighting the individual company Input and Output indexes.[27] The TFP and PFP results are provided in the following sections; details of the TFP and PFP data sources and methodology are provided in Appendix B.

3. TFP Results

The TFP growth rates, representing the difference between the output quantity and TFP input quantity[28] index growth rates, are shown in the following figures.

Figure 12: TFP Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[29] (2000-2011)

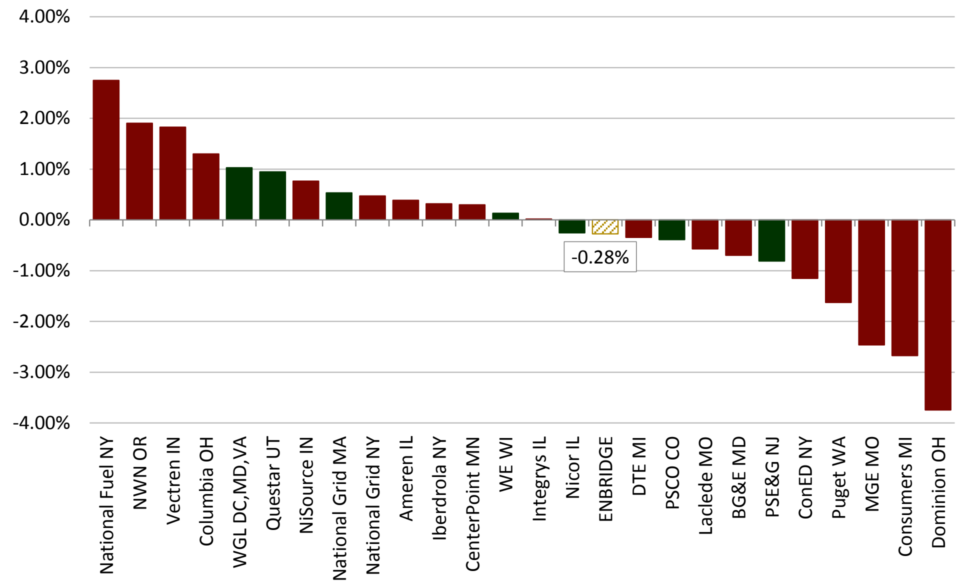


Figure 12 indicates that the TFP index growth rate for many companies has been negative over the 2000 to 2011 period. Negative TFP growth indicates that TFP input quantities (i.e., the combination of capital, materials and labour) are growing faster than output quantities (i.e., number of customers).

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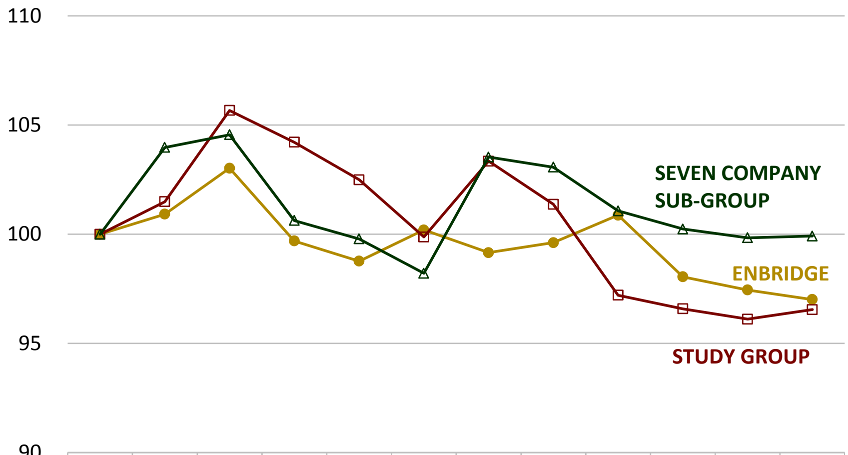
27 Company-specific input indexes were weighted by input costs; company-specific output indexes were weighted by total distribution revenue.

28 TFP Input Quantities are represented by capital, labour and materials.

29 The companies in the seven company sub-group are indicated by green shading.

Figure 13: TFP Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	101	103	100	99	100	99	100	101	98	97	97
Study Group	100	101	106	104	102	100	103	101	97	97	96	97
7 Co. Sub-Group	100	104	105	101	100	98	104	103	101	100	100	100

Figure 14: TFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		TFP Growth Rate	TFP Index	TFP Growth Rate	TFP Index	TFP Growth Rate	TFP Index
Pre-IR	2000		100.00		100.00		100.00
	2001	1.48%	101.49	3.90%	103.97	0.91%	100.92
	2002	4.03%	105.67	0.56%	104.56	2.06%	103.02
	2003	-1.39%	104.21	-3.83%	100.63	-3.29%	99.69
	2004	-1.66%	102.49	-0.84%	99.78	-0.93%	98.77
	2005	-2.59%	99.87	-1.59%	98.21	1.44%	100.20
	2006	3.42%	103.34	5.27%	103.53	-1.04%	99.16
	2007	-1.93%	101.37	-0.45%	103.07	0.46%	99.61
During IR	2008	-4.19%	97.21	-1.96%	101.07	1.25%	100.87
	2009	-0.64%	96.58	-0.82%	100.24	-2.84%	98.05
	2010	-0.49%	96.11	-0.40%	99.84	-0.62%	97.44
	2011	0.46%	96.55	0.08%	99.92	-0.45%	97.01
Average Annual Growth Rates							
Whole Period	2000-2011	-0.32%		-0.01%		-0.28%	
Pre-IR	2000-2007	0.19%		0.43%		-0.06%	
During IR	2007-2011	-1.22%		-0.78%		-0.66%	

Over the entire 2000 to 2011 study period, the seven company sub-group TFP growth rate, -0.01%, is higher than the 25 company industry study group TFP growth rate, -0.32%, which indicates greater TFP growth for the seven company sub-group. For the study period of 2000 to 2011, EGD's TFP growth rate, -0.28%, is very similar to the industry study group average of -0.32%, but lower than the seven company sub-group average of -0.01%. Although the industry group that Pacific Economics Group ("PEG") used in recent TFP analyses for Ontario electric distributors was different from the industry study group in Concentric's TFP analysis, PEG's TFP results using indexing methods (-0.05% and 0.1%) and using econometric methods (-0.03% and 0.07%) are very similar to Concentric's seven company sub-group TFP result (-0.01%).[30,31]

Likely as a result of the economic recession that started in 2008 and ongoing DSM/energy efficiency programs, TFP growth rates from 2007 to 2011 were less than TFP growth rates from 2000 to 2007 for Concentric's three TFP indexes – the industry study group, seven company sub-group and EGD. However, the decline in EGD's TFP growth rate from 2000 to 2007 compared to 2007 to 2011 (-0.60%[32]) was less than the industry group's TFP growth rate decline (-1.41%,[33]) and also less than the seven company sub-group's TFP growth rate decline (-1.21%.[34]) As a result, Enbridge outperformed both industry groups over the most recent period. EGD's relative productivity performance may be explained by (a) the incentives for improvements in efficiency that resulted from EGD's 1st Generation IR plan, and (b) EGD's relatively high output (i.e., customer) growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

4. PFP Results

The PFP input quantity index is an aggregation of labour and materials quantity sub-indexes; the PFP input quantity index differs from the TFP input quantity index in that the PFP input quantity index excludes capital quantities. Concentric measured output growth for both the PFP and TFP output quantity index as the annual growth in customers. The PFP index growth rates, representing the difference between the output quantity and PFP input quantity index growth rates, are shown in Figures 15, 16 and 17.

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30 Pacific Economics Group Research, LLC, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised on May 31, 2013.

31 PEG's TFP results would have been -1.24% (May 3, 2013 Report) or -1.10% (May 31, 2013 revision) if they had included Toronto Hydro and Hydro One, which they excluded from their analyses.

32 EGD's Change in TFP growth = 2007 to 2011 TFP growth – 2000 to 2007 TFP growth = (-0.66%) – (-0.06%) = -0.60%

33 The Industry Study Group's Change in TFP growth = 2007 to 2011 TFP growth – 2000 to 2007 TFP growth = (-1.22%) - (0.19%) = -1.41%

34 The Seven Company Sub-Group's Change in TFP growth = 2007 to 2011 TFP growth – 2000 to 2007 TFP growth = (-0.78%) - (0.43%) = -1.21%

Figure 15: PFP Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[35] (2000-2011)

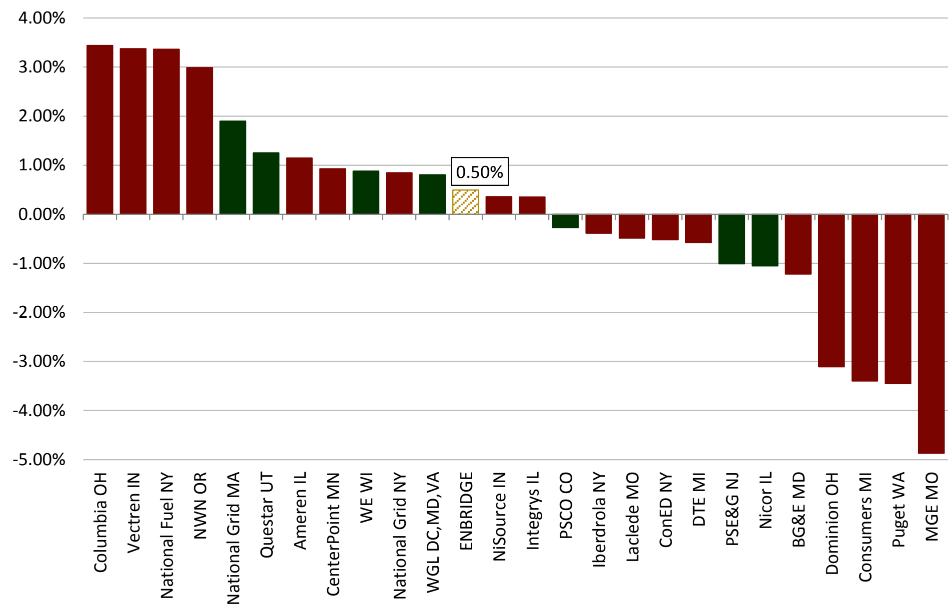
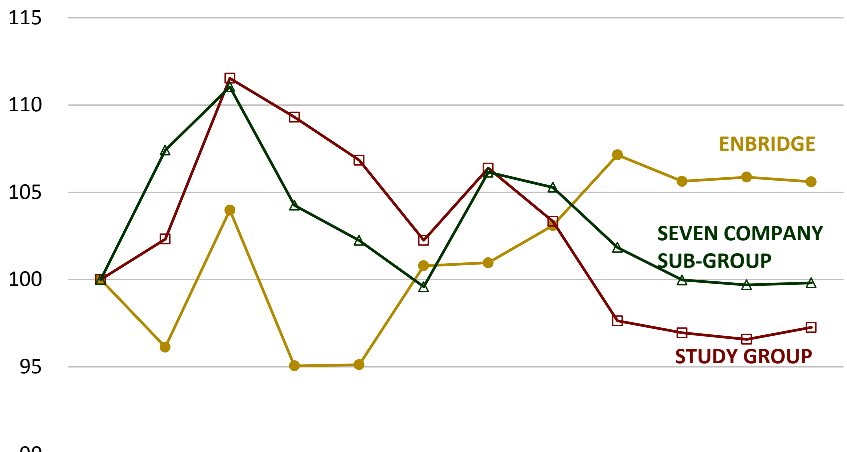


Figure 15 illustrates that many companies experienced negative PFP growth over the 2000 to 2011 period; negative PFP growth indicates that PFP input quantities (i.e., the combination of materials and labour) are growing faster than output quantities (i.e., number of customers).

[35] The companies in the seven company sub-group are indicated by green shading.

Figure 16: PFP Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	96	104	95	95	101	101	103	107	106	106	106
Study Group	100	102	112	109	107	102	106	103	98	97	97	97
7 Co. Sub-Group	100	107	111	104	102	100	106	105	102	100	100	100

Figure 17: PFP Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		PFP Growth Rate	PFP Index	PFP Growth Rate	PFP Index	PFP Growth Rate	PFP Index
Pre-IR	2000		100.00		100.00		100.00
	2001	2.30%	102.32	7.16%	107.42	-3.94%	96.13
	2002	8.62%	111.54	3.32%	111.04	7.85%	103.98
	2003	-2.02%	109.30	-6.31%	104.25	-8.97%	95.06
	2004	-2.28%	106.84	-1.95%	102.24	0.07%	95.12
	2005	-4.39%	102.25	-2.63%	99.58	5.79%	100.79
	2006	3.96%	106.38	6.38%	106.15	0.17%	100.96
	2007	-2.90%	103.34	-0.82%	105.29	2.09%	103.10
During IR	2008	-5.67%	97.64	-3.33%	101.84	3.85%	107.14
	2009	-0.71%	96.95	-1.85%	99.98	-1.42%	105.63
	2010	-0.38%	96.58	-0.28%	99.70	0.23%	105.87
	2011	0.70%	97.26	0.12%	99.81	-0.25%	105.60
Average Annual Growth Rates							
Whole Period	2000-2011	-0.25%		-0.02%		0.50%	
Pre-IR	2000-2007	0.47%		0.74%		0.44%	
During IR	2007-2011	-1.52%		-1.33%		0.60%	

Over the entire 2000 to 2011 study period, the seven company sub-group PFP growth rate, -0.02%, is higher than the 25 company industry study group PFP growth rate, -0.25%, which indicates greater PFP growth for the seven company sub-group. For the study period of 2000 to 2011, EGD's PFP rate, 0.50%, is significantly higher than the industry study group average, -0.25%, and the seven company sub-group average of -0.02%, indicating that Enbridge was more productive than both groups. PFP growth rates from 2007 to 2011 were less than PFP growth rates from 2000 to 2007 for both the industry study group and the seven company sub-group; the industry study group's PFP declined by -1.98%[36] and the seven company sub-group's PFP declined by -2.07%[37]. However EGD's PFP improved by 0.16%[38] between 2000 to 2007 and 2007 to 2011. EGD's PFP improvement between 2000 to 2007 and 2007 to 2011 may again be attributable to (a) the incentives for improvements in efficiency that resulted from EGD's 1st Generation IR, and (b) EGD's relatively high output (i.e., customer) growth rate from 2007 to 2011, compared to industry study group or seven company sub-group companies.

5. *X Factor*

The creation of incentives for greater productivity lies at the heart of IR plans. In an I-X framework, X is an explicit measure of productivity, typically measured through analysis of historical industry performance. In a "building block" approach, X may be derived from the total revenue path, or used to evaluate the productivity embedded in the projected revenue path. The analysis of productivity and calculation of X provided by Concentric serves two roles in EGD's proposed plan: (1) the TFP industry X was used to evaluate the sufficiency of an I-X rate path for EGD's Allowed Revenue amounts; and (2) the PFP industry X was used to evaluate the productivity embedded in EGD's O&M budgets for the 2014 to 2016 period. In sum, EGD requested that Concentric develop an X Factor, and forecasted I Factors (discussed in Section V) to evaluate the reasonableness of the Allowed Revenue amounts that are included in EGD's Customized IR plan.

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36 The Industry Study Group's Change in TFP growth = TFP growth during IR – TFP growth prior to IR period = (-1.52%) - (0.47%) = -1.98%

37 The Seven Company Sub-Group's Change in TFP growth = TFP growth during IR – TFP growth prior to IR period = (-1.33%) - (0.74%) = -2.07%

38 EGD's Change in TFP growth = TFP growth during IR – TFP growth prior to IR period = (0.60%) – (0.44%) = 0.16%

To develop X factors based on the TFP and PFP analyses discussed above, Concentric considered: (1) whether EGD, the industry study group, or the seven company sub-group productivity results should be used, and (2) the appropriate time frame to include.

It is appropriate to evaluate EGD based on the industry productivity standard. Looking to a peer group sample of companies provides an objective measure of similarly situated companies, and avoids over-reliance on individual company data that may be skewed by unique operating circumstances, accounting practices, or regulatory treatment, provided that the study group is sufficiently representative. Regarding whether the 25 company industry study group or the seven company sub-group should be used, Concentric used the seven company sub-group TFP and PFP results to develop an X Factor because, for all three time periods, the seven company sub-group results were higher than the 25 company industry study group, and therefore represented a more aggressive productivity target.

In choosing the years on which to base the productivity analysis to be used to estimate the X factor, it is necessary to balance three factors: (1) using a sufficiently long period to smooth out the effects of year-to year variations; (2) using a sufficiently short, and recent period to reflect expected productivity growth in the near term; (3) data availability. Ideally, productivity analyses should include the most recent 10-15 years of data.

As demonstrated in Figures 14 and 17, the TFP and PFP Index growth rates vary from year to year and over time. For example, the average TFP Index for the seven company sub-group over 2000 to 2011 is -0.01%, but would be -0.78% if computed over the more recent 2007 to 2011 period. The average PFP Index for the seven company sub-group over 2000 to 2011 is -0.02%, but would be -1.33% if computed over the more recent 2007 to 2011 period. The recent decline in productivity has been the result of an increase in the input index, accompanied by slowing increases in the output index over the same time period. Experts in the application of utility IR plans offer "When no major structural changes are anticipated in the economy, historic data on productivity and input price growth rates often provide reasonable estimates of corresponding future growth rates."[39] Using the 2000 to 2011 period for determination of the TFP and PFP on a going forward basis represents a built in challenge requiring reversal of recent slowing output growth and rising input growth.

Concentric recommends using TFP and PFP X Factors of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan, based on the 2000

[39] Bernstein and Sappington, 'How to Determine the X in RPI – X regulation: A User's Guide", *Telecommunications Policy*, 24, 2000, p. 65.

to 2011 TFP results for the seven company sub-group of -0.01% and the 2000 to 2011 PFP results for the seven company sub-group of -0.02%. Concentric's recommendation of an X Factor of 0% is identical to PEG's recommended X Factor of 0% for the Ontario electric distributors contained in their May 3, 2013 report to the Board, and very similar to PEG's recommended X Factor of 0.1% contained in their May 31, 2013 revision.[40]

Concentric's recommended TFP-based X Factor of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan can be viewed as presenting a built-in productivity challenge to EGD of 30-75 basis points. As discussed previously, the 25 company industry study group TFP results would suggest an X Factor of -0.32%; however Concentric is recommending a more aggressive X Factor of 0% based on the seven company sub-group TFP results, implying a productivity challenge of approximately 30 basis points for EGD. In addition, Concentric is using the entire 2000 to 2011 time frame from the seven company sub-group TFP to derive our recommended X Factor; if Concentric had used the more recent 2007 to 2011 time period, the X Factor recommendation could have been lower by over 75 basis points. Similarly, Concentric's recommended PFP-based X Factor of 0% can be viewed as presenting a built in productivity challenge to EGD of 20-130 basis points. Concentric believes that the X factor recommendation of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan provides EGD with an aggressive productivity challenge.

A stretch factor is an optional adder to the X factor, which increases the offset to the I Factor and therefore decreases revenue per customer growth. The stretch factor acts as a customer benefit factor in that it assigns to customers a minimum level of the benefits of expected productivity growth beyond that captured in the X factor; rates are reduced to account for the stretch factor, regardless of whether the utility achieves that incremental productivity growth. In Concentric's view, there are generally two situations in which a stretch factor may be appropriate: (a) when a utility is transitioning from cost of service regulation to performance or incentive based regulation, and (b) to reflect that the utility is less efficient than its peers.[41] Neither of these situations applies to EGD. EGD has been under some form

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[40] Pacific Economics Group Research, LLC, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised on May 31, 2013.

[41] Both of these situations are consistent with views on stretch factors contained in PEG's May 3, 2013 report and May 31, 2013 revision to the Board. "PEG also recommends that the stretch factor for the largest group be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time" (p. 90); "Larger stretch factors are assigned for relatively less

of incentive regulation for a number of years, and has been operating under its 1st Generation IR plan since 2008. In addition, based on the results of cost benchmarking analyses conducted by Concentric, EGD is among the most efficient of its U.S. and Canadian peers.

While the Ontario electric utilities have performance-based stretch factors, the justification for the stretch factors was in part due to preference of a stretch factor over an earnings sharing mechanism. In the 3rd Generation IR for electric distributors, the Board observed that "[stretch factors] are somewhat analogous to earnings sharing mechanisms."[42] However, because EGD is proposing an earnings sharing mechanism, if EGD is able to produce additional productivity growth, the additional earnings beyond the dead band will be shared with customers. Therefore, a stretch factor is not necessary because EGD's proposed ESM achieves customer benefits that might otherwise be achieved with a stretch factor, with additional opportunity for greater customer benefits.

Therefore, Concentric determined that an explicit stretch factor is not necessary because (a) EGD has ample experience under an IR regime – EGD is not embarking on a 1st Generation IR Plan; (b) EGD is a relatively efficient utility, (c) EGD's proposed ESM provides opportunities for customer benefits in place of a stretch factor, and (d) Concentric's X Factor recommendation can be viewed as having a built-in productivity challenge.

E. Conclusions

Concentric's benchmarking analysis demonstrates that EGD is currently an efficient utility and that EGD has continued to improve its performance relative to its industry peers, especially related to O&M costs. Furthermore, Concentric's productivity analysis demonstrates that EGD improved its productivity as measured by both TFP and PFP during the 1st Generation IR plan (2007 – 2011) compared to the pre-IR plan period (2000 - 2007) relative to performance of both the 25 company industry study group and the seven company sub-group during those same periods, which indicates that EGD made productivity improvements during the 1st Generation IR plan. This suggests that the potential productivity improvements that are often available at the onset of IR may have less potential in the 2nd Generation IR. While it is important that EGD continue to look for additional efficiency and productivity improvement opportunities, they may be more difficult for EGD

efficient distributors since they are deemed to have greater potential to achieve incremental productivity gains." (p. 89); and PEG assigned a stretch factor of 0 to the most efficient group. (p. 90)

42 "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, EB-2007-0673, September 17, 2008, p. 19.

to find. Based on Concentric's TFP and PFP analyses, Concentric recommends an X Factor of 0% to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan.

V. MEASURE OF INFLATION

A. Introduction

In a stable, competitive environment, economic theory suggests that a firm's costs will increase by price inflation minus productivity improvements; this principle is the basis for I-X incentive ratemaking formulas. The purpose of the I Factor in an I-X formula is to account for inflation in input prices, whereas the X Factor accounts for productivity. Concentric was asked by EGD to provide a recommendation for an appropriate I Factor to be used with a productivity factor to evaluate the reasonableness of the Allowed Revenue amounts included in EGD's Customized IR plan. To develop our recommendations, Concentric researched the use of I Factors in I-X incentive ratemaking formulas in Ontario as well as in other jurisdictions, and conducted related analysis.

Utilities employ labour, materials and capital as inputs in their operations, and the associated labour, materials and capital prices are generally considered to be outside the control of the utility. Concentric's I Factor is therefore designed to accommodate increases in these input prices. The I Factor used for the purposes of this evaluation should generally meet the following criteria:

- Published by a reliable outside source (e.g., a government agency or reputable third party)
- Available on a timely basis
- Relatively uninfluenced by the performance of the utility to which it is being applied
- Reflective of the input prices facing the industry to which it is being applied (in this case gas distribution)

In addition, the I Factor should be relatively straightforward to calculate.

There are two common approaches to developing the I Factor used in I-X type formulas: (1) using a single macroeconomic index; or (2) using a composite I Factor. The benefit of a macroeconomic I Factor in an I-X formula, such as GDP-IPI-FDD[43] that was used in EGD's 1st Generation IR plan, is that it is straightforward to implement.[44] However, using a macroeconomic index for the I Factor presents a number of challenges, including requiring implicit adjustments to the X Factor. The macroeconomic index chosen is typically a

43 GDP-IPI-FDD: Gross Domestic Product Implicit Price Index Final Domestic Demand

44 A macroeconomic I Factor would be determined by calculating the annual change in the published macroeconomic index.

measure of output prices in the overall economy (e.g., a measure of GDP); however, the goal is to identify an input price inflation index for the gas distribution industry. Therefore, it is necessary to adjust the macroeconomic index (a) for the difference between the input prices experienced by the industry and the input prices in the overall economy, and (b) to account for the difference in productivity between the economy and the industry.[45] These implicit X Factor adjustments require additional data, and details associated with the calculations can be subject to debate. Also, the X Factor adjustments are typically fixed at a point in time, so any changes in the relationship between industry and economy input prices, or the change in productivity between the industry and economy will not be captured. In addition, to the extent that the macroeconomic index does not accurately reflect the utility's input prices (even with the implicit adjustments), it could lead to unjustified swings in earnings or customer costs.

Some jurisdictions have chosen to adopt a composite I Factor in their I-X formulas that more directly reflects input prices faced by utilities. A composite I Factor is calculated as a weighted average of separate indices that track changes in items such as labour prices, materials prices, and capital prices faced by the utility. A composite I Factor is a more direct measure of utility input prices, so it eliminates the need to make implicit adjustments to the X Factor to account for the difference between input prices and productivity of the industry and the economy. The challenges of a composite I Factor include choosing the specific indices to represent the separate price components, and identifying the weights to apply to each index to develop the composite I Factor. In addition, the methodology chosen to develop the composite I Factor can be relatively simple, or it can be very complex, depending on the approach taken.

B. I Factor Recommendation

Concentric considered the benefits of the continued use of the existing GDP-IPI-FDD inflator versus a composite factor to evaluate the Allowed Revenue amounts included in EGD's Customized IR plan. In doing so, Concentric researched a broad array of potential indices and examined their sources, components and availability. Based on the availability of price indexes that more specifically reflect labour and capital costs, and the historical evidence that illustrates the potential for these cost indices to diverge from the general rate of inflation, we believe it is appropriate to utilize those more specific indices to reflect price

[45] This second adjustment is necessary because the macroeconomic index is a measure of output prices, which includes the productivity of the economy in converting inputs to outputs.

changes in those specific inputs.[46] In addition, the implicit adjustments to the X Factor that are necessary to account for the differences in productivity and input prices embedded in the generic macroeconomic index require additional data, can be imprecise, and the appropriate methodology can be controversial. Concentric therefore believes it is preferable to use a composite I Factor that explicitly tracks changes in input prices and eliminates the need for X Factor adjustments. On balance, we recommend a composite I Factor comprised of a weighted average of the following indices: (1) Ontario Average Hourly Wages (all employees) for labour-related prices,[47] (2) Canada GDP-IPI-FDD for materials prices,[48] and (3) Canada implicit price index for net gas distribution plant for capital prices as shown in the following graph.[49]

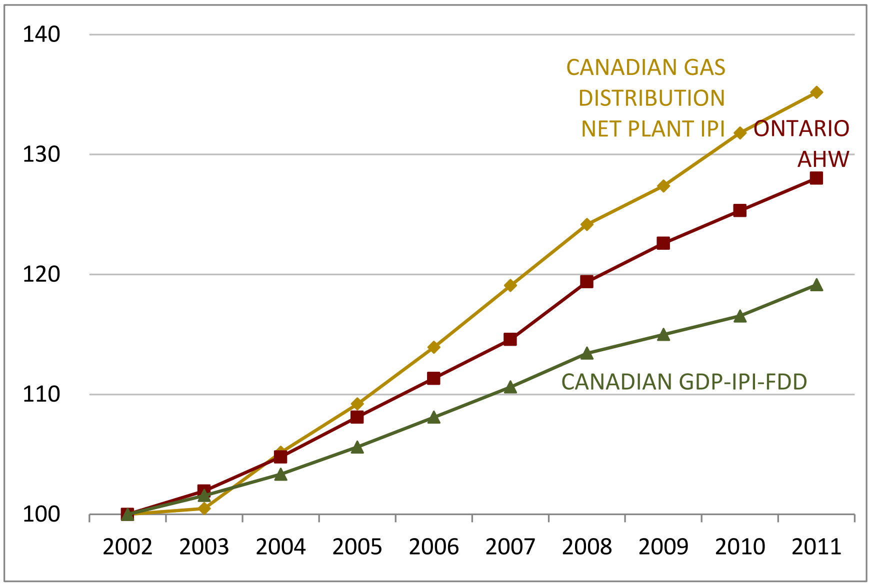
46 We have not identified a superior alternative to the GDP-IPI-FDD inflator for materials, so we continue to use that index.

47 Source: Statistics Canada. Table 282-0069 - Labour force survey estimates (LFS), Ontario, All Employees, wages of employees by type of work, National Occupational Classification for Statistics (NOC-S), sex and age group, unadjusted for seasonality; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on March 1, 2013.

48 Source: Statistics Canada, Table 380-0066, Gross domestic product (GDP) indexes, Canada, Implicit price indexes, Final domestic demand, quarterly (2007=100) available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on April 1, 2013.

49 Source: Statistics Canada, Table 031-0002, Flows and stocks of fixed non-residential capital, by North American Industry Classification System (NAICS) and asset, annual (dollars x 1,000,000); Canada; Current Prices and 2007 Constant Prices; Natural Gas Distribution; Geometric end-year net stock; Total assets; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on March 1, 2013.

Figure 18: Graph of I Factor Price Sub-Indices (Indexed to 2002)



The historical data for these three sub-indices illustrates that input prices for capital (Canadian Gas Distribution Net Plant IPI) and labour (Ontario AHW) have escalated more rapidly than overall inflation (Canadian GDP-IPI-FDD), which indicates that Canadian GDP-IPI-FDD is not an ideal representation of labour or capital input prices. This is not surprising given the rising costs of steel and plastic over this period, and continued pressure on labour costs experienced in Ontario and elsewhere.

In addition, the proposed indices meet all the I Factor criteria listed in Section V.A above. First, the three indices are publicly available from Statistics Canada. The Ontario Average Hourly Wages is published monthly, the Canadian GDP-IPI-FDD is published quarterly, and the Net Plant implicit price index data is published annually, so they are available on a timely basis. As shown in Figure 18, all indices are relatively stable. While EGD is a large utility in Ontario, its employment levels do not significantly affect the Ontario Average Hourly Wage index for all employees. Conversely, given that EGD is competing against other Ontario businesses in the labour market, the Ontario Average Hourly Wage index for all employees is a good indicator of the labour price pressures faced by EGD. EGD is certainly not large enough to affect the measurement of Canadian GDP-IPI-FDD; likewise, Canadian GDP-IPI-FDD remains a reasonable proxy for the non-labour input price pressures faced by EGD. Lastly, due to the difficulty in obtaining a capital price index for Ontario natural gas utilities, Concentric determined that the net gas distribution plant index for Canada is the most appropriate indicator of the capital cost pressures faced by EGD. Figure

21 contains graphs of these three price indices, and Concentric's recommended composite indices for both two and three component inputs ("sub-indices"), indexed to 2002.

To develop a comprehensive TFP I Factor applicable to all three input components (i.e., labour, capital and materials), Concentric weighted the labour price index by 19%, the materials price index by 33%, and the capital price index by 48%. For a partial PFP I Factor applicable to labour and materials, Concentric weighted the labour price index by 38% and the materials price index by 62%. The weights are based on the 2009 to 2011 average cost weights for the input sub-indexes from the seven company sub-group TFP and PFP analyses, as shown in Figures 19 and 20. Using industry cost weights rather than EGD's cost weights, appropriately eliminates EGD's ability to affect the weighting of the sub-indices for the I Factor.

Figure 19: 2009-2011 Average Input Sub-Index Cost Weights

Seven Company Sub-Group TFP

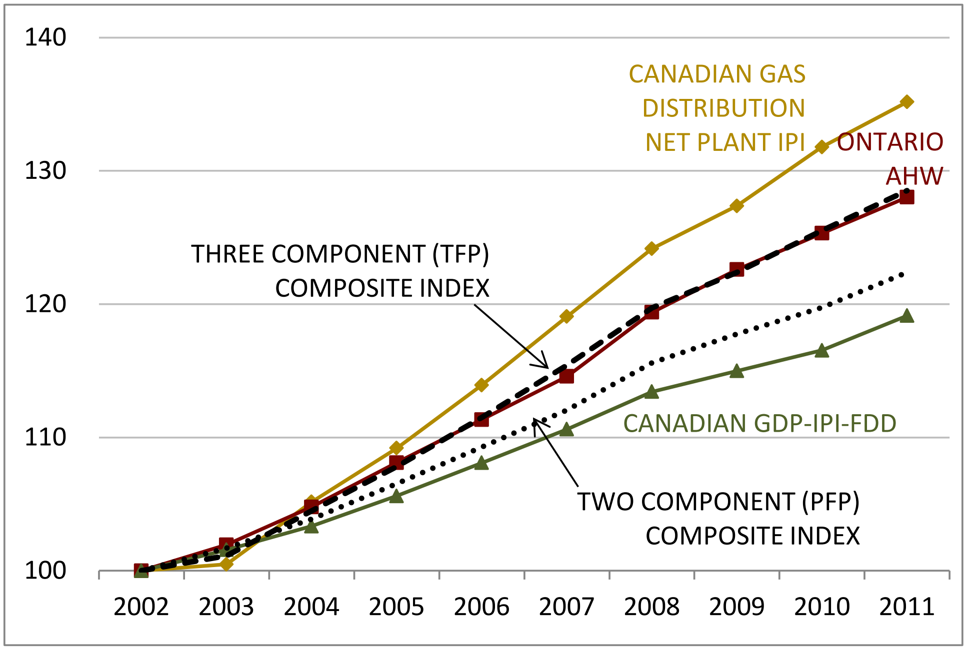
	Capital	Labour	Materials
2009	51%	18%	31%
2010	51%	18%	30%
2011	43%	21%	37%
2009-2011 Average	**48%**	**19%**	**33%**

Figure 20: 2009-2011 Average Input Sub-Index Cost Weights

Seven Company Sub-Group PFP

	Labour	Materials
2009	38%	62%
2010	39%	61%
2011	37%	63%
2009-2011 Average	**38%**	**62%**

Figure 21: Graph of I Factor Composite Price Indices (Indexed to 2002)



While the specific indices chosen and the specific calculations differ, Concentric's approach to developing a composite I Factor is comparable to the approach used in PEG's recent reports to the Board as part of the development of the 4th Generation Incentive Rate-setting for electricity distributors.[50] PEG recommends a composite I Factor (called an industry input price index ("IPI") in PEG's reports) comprised of a weighted average of separate input price indices for capital, labour and materials, and the weights are determined using the input sub-index average cost weights from their TFP analysis.

C. I Factor Forecast

Concentric developed a forecast of each of the price indices contained in the I Factor recommended to evaluate EGD's Allowed Revenue amounts. Because we believe that the Canadian government does not publish forecasts of these indices, Concentric prepared forecasts, based on our estimates of the historical relationship between each index and the broader Consumer Price Index ("CPI") for Canada, which does have an available forecast.[51]

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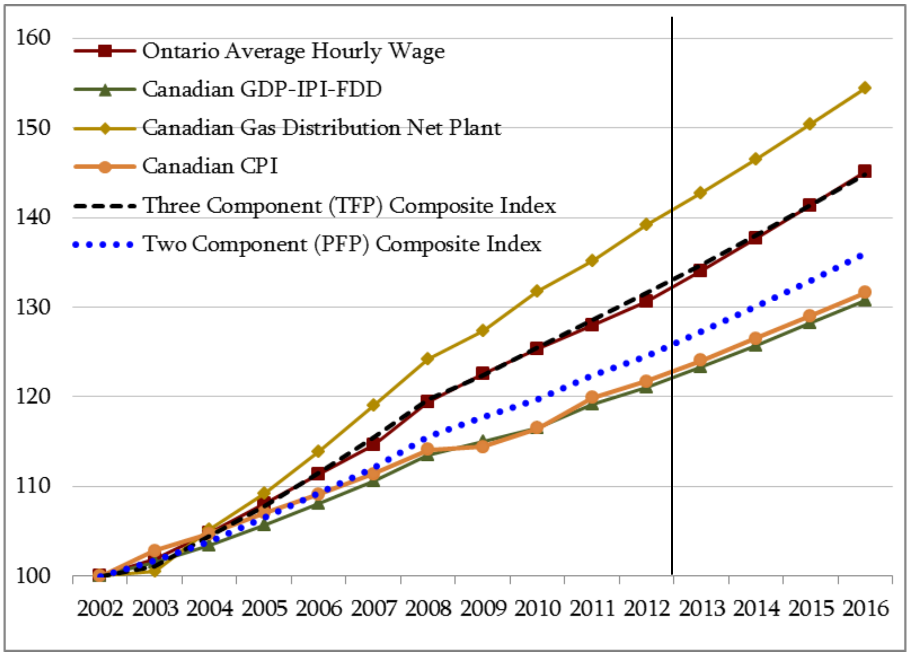
[50] Pacific Economics Group Research, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board," May 3, 2013, subsequently revised May 31, 2013.

[51] *Consensus Forecasts,* Consensus Economics, October 8, 2012, p.28.

Based on the historical relationship between Canadian CPI and each of the three sub-indices (measured through simple linear regressions), projections were developed for each of the three sub-indices. These sub-index forecasts were aggregated, using the historical weights, to create projections for both the two and three-component composite I Factors. The projections for each sub-index and the composite indices are presented in Figure 22.

Figure 22: Graph of Projected I Factor Price Indices



The following I Factor growth forecasts are used to evaluate Enbridge's Allowed Revenue amounts for the 2014 to 2016 period.

Figure 23: Projected Percent Annual Change in I Factor Price Indices

	2013	2014	2015	2016
Canadian CPI	1.90%	2.00%	2.00%	2.00%
Ontario Average Hourly Wage	2.62%	2.66%	2.66%	2.66%
Canadian GDP-IPI-FDD	1.88%	1.96%	1.96%	1.96%
Canadian Gas Distribution Net Plant	2.56%	2.66%	2.66%	2.66%
Three Component (TFP) Composite Index	2.36%	2.45%	2.45%	2.45%
Two Component (PFP) Composite Index	2.18%	2.24%	2.24%	2.24%

VI. TREATMENT OF O&M COSTS

EGD's proposed Customized IR plan sets the Company's Allowed Revenue amounts based on the Company's annual forecast of O&M costs, depreciation costs, taxes and cost of capital. This section presents and evaluates EGD's forecast O&M cost component of the Allowed Revenue amounts for 2014 to 2016.[52]

Figure 24 contains EGD's 2013 Board-approved O&M costs, as well as EGD's forecasted O&M budgets for 2014 to 2016. Total O&M expenses have been separated into (a) flow-through items, which are subject to fixed budgets approved in separate proceedings (i.e., Customer Care, Pensions, and DSM), and (b) all other O&M. For comparison purposes, EGD's 2013 Board-approved, and 2014 to 2016 forecasted customer count and resulting forecasted O&M costs per customer are also contained in Figure 24.

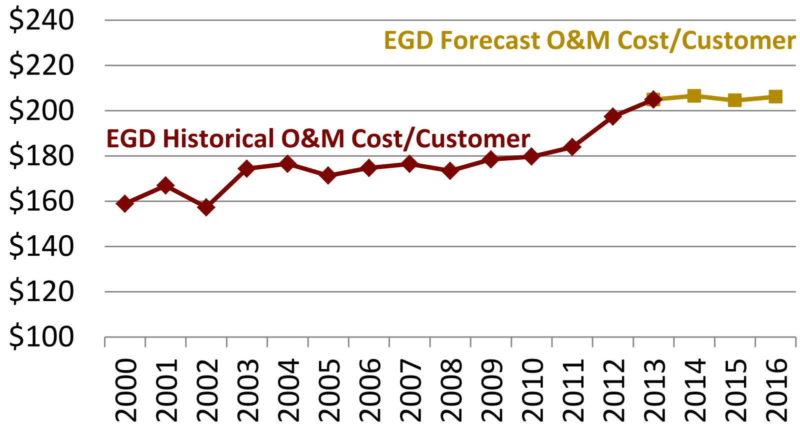
Figure 24: EGD O&M Costs, Customers, and O&M Costs/Customer

	2013 Approved	2014 Forecast	2015 Forecast	2016 Forecast
Customer Care, Pensions, DSM ($Millions)	$164	$162	$163	$165
All Other O&M ($ Millions)	$251	$263	$265	$275
Total Utility O&M Expense ($ Millions)	**$415**	**$425**	**$429**	**$440**
Customer Count	2,025,462	2,059,619	2,095,302	2,131,887
Total O&M Cost per Customer ($/Customer)	$205	$207	$205	$206

To test the reasonableness of EGD's 2014 to 2016 O&M budget, Concentric performed two analyses. First, Concentric compared EGD's total forecast O&M cost per customer to EGD's historical trend of total O&M costs per customer. As noted in Figure 7 in the benchmarking discussion, EGD's O&M cost per customer is already among the lowest in the industry; in 2011 EGD had the fifth lowest O&M cost per customer in an industry study group comprised of 28 U.S. natural gas utilities. As shown in Figure 25, EGD's forecasted O&M cost per customer is forecasted to be higher than recent history, but not by a significant amount.

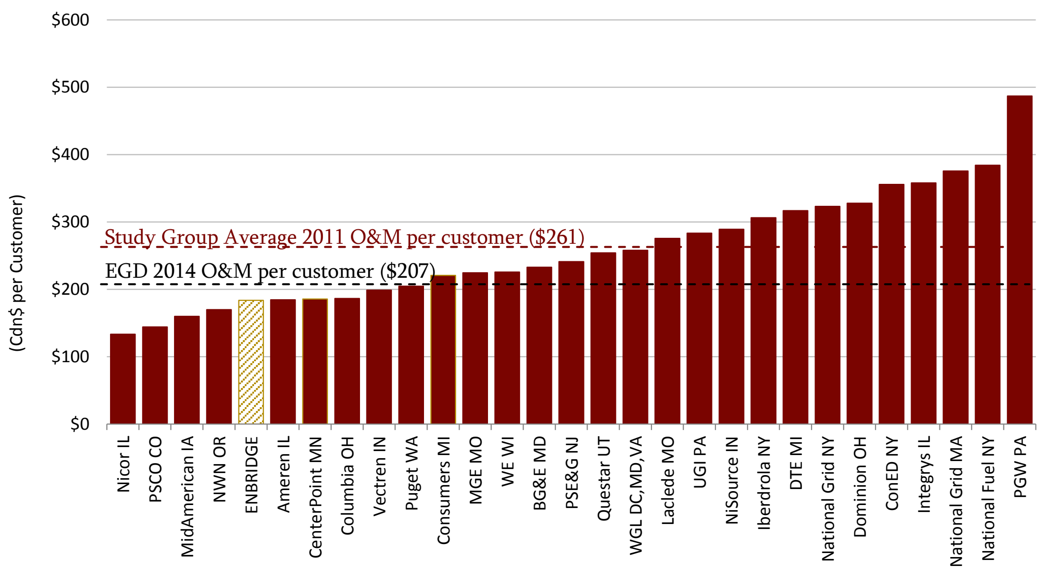
52 Concentric's assessment of EGD's forecast capital cost component of the Allowed Revenue amounts for 2014 to 2016 is provided in Section VII.

Figure 25: EGD O&M Costs/Customer (2000-2016)



It is also notable that EGD's forecasted O&M cost per customer of $207 in 2014 is significantly lower than the industry study group average of $261 for 2011.

Figure 26: Total 2011 Gas O&M Expenses per Customer with EGD 2014 Total O&M Cost per Customer Forecast[53]

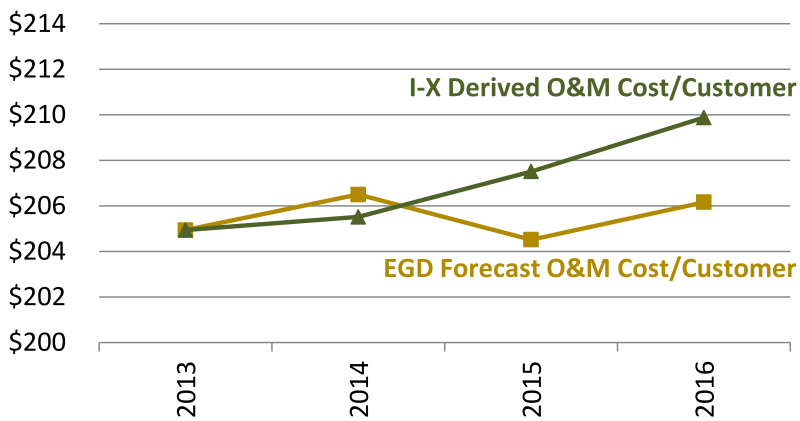


For the second analysis, Concentric compared EGD's forecasted Total O&M cost per customer with the O&M cost per customer that is derived from (a) applying the projected PFP I-X growth rates to the "all other" O&M category of costs per customer, plus (b) EGD's

[53] The 2011 and 2014 O&M cost per customer data are presented in nominal Canadian dollars. If the effects of inflation were removed from EGD's 2014 forecast O&M cost per customer, EGD's 2014 forecast would be even lower.

projected Customer Care, Pensions and DSM pass-through costs.[54] As shown in Figure 23 in Section V.C (Measure of Inflation), the two-component composite I Factor is projected to grow at 2.24% per year from 2014 to 2016. This combined with a PFP X Factor of 0% implies that "All Other" (Non-flow through) O&M cost per customer would be expected to increase by 2.24% under a PFP I-X framework applied to O&M costs. A comparison of EGD's forecasted total O&M cost per customer and the O&M cost per customer derived from applying the PFP I-X formula to the non-flow through O&M costs per customer is shown in Figure 27:

Figure 27: EGD O&M Costs/Customer versus PFP I-X ($/Customer)



As shown in Figure 27 above, EGD's forecasted O&M cost per customer is higher than the O&M cost per customer derived from applying the PFP I-X formula in 2014 and is lower than the O&M cost per customer derived from applying the PFP I-X formula in 2015 and 2016.

Figure 28 demonstrates EGD's forecasted O&M cost in aggregate is approximately $2 million higher than the PFP I-X derived O&M cost in 2014, $6 million less in 2015 and $8 million less in 2016, for a cumulative 2014 to 2016 productivity savings, compared to I-X O&M growth of approximately $12 million, compared to the PFP I-X formula.

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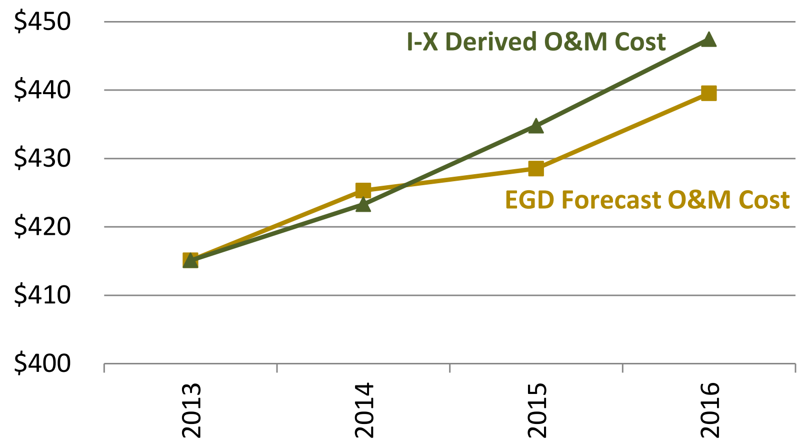
54 Costs associated with Customer Care, Pensions and DSM have been determined by the Board to be pass through costs in Board decisions in other proceedings.

Figure 28: EGD O&M Costs versus PFP I-X ($Millions)



Concentric's analyses indicate that EGD's forecasted O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to productivity from the seven company sub-group PFP analysis. The $12 million in cumulative savings between the PFP I-X derived O&M costs and the EGD forecasted O&M cost can be viewed as additional productivity flowing through to customers, beyond the productivity that would be built into a PFP I-X formula.

VII. TREATMENT OF CAPITAL COSTS

A. Introduction

EGD asked Concentric to assess EGD's proposed approach to recover the costs of its projected 2014 to 2016 capital spending. This Section provides a summary of Concentric's assessment. Also included is (1) an overview of traditional and non-traditional ratemaking approaches that are currently being used in Canada and the U.S. to recover capital costs; and (2) a summary of Concentric's analyses that measure the effect of these capital cost recovery ratemaking approaches on EGD's opportunity to earn a fair return. The overview of ratemaking approaches and the summary of Concentric's analyses serve as the basis for Concentric's assessment.

B. Recovery of Capital Costs

Traditional cost of service / rate of return regulation, as practiced by provincial and state regulatory agencies, is based on an analysis of a utility's projected or historical annual cost of doing business; this analysis determines the level of revenues ("revenue requirement")[55] that would allow the utility a reasonable opportunity to earn a fair rate of return.[56]

In simple terms, the rates that are charged to customers are determined by dividing the revenue requirement by the units of sales; the units of sales are determined in a manner that is intended to be representative of the sales that are likely to be experienced in the period when the new rates will take effect.[57] Lastly, customer charge rates, volumetric rates and demand rates to be billed to customers in each rate class are calculated.

Traditional ratemaking is designed to provide regulated utilities with a reasonable opportunity to earn a fair rate of return if the conditions that affect utility costs and revenues

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[55] The revenue requirement consists of (1) expenses, (2) return <u>of</u> investment in plant (depreciation), (3) return <u>on</u> investment in plant, and (4) taxes. The return on investment component of the revenue requirement accounts for the cost of debt that the utility has issued and the cost of equity, which is determined by analysis to be the return that will allow the utility to maintain credit, attract investment and provide returns that are comparable to like-risk investments.

[56] Typically, when the rate making process is based on historical data, adjustments are made to the data to ensure that the historical costs are representative of the costs that are likely to be experienced in the future period when the new approved rates will take effect.

[57] The detailed determination of the rates to be charged involves (a) assigning an appropriate and fair portion of the total revenue requirement to each of the rate classes that receives service from the company, and (b) separating the class revenue requirement into the portions that will be recovered from each of the types of units of sales – billing determinants - that apply to that rate class, e.g. customer, commodity or energy, and demand.

during the period that the rates will be charged are generally similar to the conditions that formed the basis for the approved rates; traditional ratemaking may not produce reasonable results when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are very different from the conditions that formed the basis for the approved rates.[58]

There has been growing recognition over the past decade among regulators and gas distribution companies that traditional ratemaking is not likely to produce reasonable results[59] because of the business and operating conditions that that are impacting the earnings of gas distribution companies. These business and operating conditions include, for example: (a) the implementation of large safety and reliability-related non-revenue producing infrastructure replacement and reinforcement programs and/or (b) limited growth in revenues as a result of utility-sponsored energy efficiency programs and general implementation of conservation measures. Under these conditions, traditional ratemaking would not provide a gas distribution company with a reasonable opportunity to earn a fair return. Further, filing frequent rate cases is not a viable solution to the shortcomings of traditional ratemaking. In addition to the administrative inefficiencies of frequent rate cases, which impact all parties, frequent rate cases will not provide a gas distribution company with a reasonable opportunity to earn a reasonable return because of delays that are inherent in the rate case process.[60]

As a result of the shortcomings of traditional ratemaking under these circumstances, over the last several years[61] a growing number of regulators have approved non-traditional rate making approaches to (a) allow for timely recovery of the costs of capital spending between rate cases; (b) offset the impact of declining delivery volumes on distribution revenues; and /

58 Also, traditional ratemaking may not produce reasonable results even when the conditions that affect utility costs and revenues in the years that the rate case rates will be charged are the same as the conditions that formed the basis for the approved rates, such as during an extended period of high rates of inflation.

59 This discussion is limited to gas distribution companies, although traditional ratemaking approaches have not been producing reasonable results for electric distribution companies in recent years as well.

60 These delays in the rate case process, often referred to as "regulatory lag," include the time between (a) the time period represented by the historical costs that are the basis for determining a distribution company's revenue requirement and (b) the effective date of the new rates that reflect the distribution company's revenue requirement.

61 Although much of the attention to non-traditional ratemaking approaches has occurred since 2005, in 1978, Pacific Gas & Electric's gas division ("PG&E) implemented a non-traditional ratemaking approach to decouple PG&E's revenues and earnings from the volumes of gas delivered so that PG&E earnings would not be impacted by the extensive energy efficiency programs that PG&E was implementing.

or (c) allow for timely recovery of specific types or categories of expenses that are largely variable from year to year.

Specifically related to EGD's request that Concentric assess EGD's proposed approach to recover the costs of its projected capital spending during EGD's Customized IR plan, there is considerable recent experience in Canada and the U.S. concerning non-traditional ratemaking approaches that allow for timely recovery of the costs of capital spending between rate cases;[62] these ratemaking approaches are often referred to as Capital Trackers. Figure 29 summarizes the three most common Capital Tracker approaches.

Figure 29: Capital Tracker Approaches

Category	Types of Eligible Assets	Examples of Eligible Assets
General Purpose	• Typically non-revenue generating • Targeted • Long term • Out of the ordinary	• Cast iron/ bare steel replacement programs • Pipeline system integrity • Relocating inside gas meters • City and state construction projects
Special Projects	• Very large • Defined, specific projects • Short term • May include revenue generating projects	• Specific system expansion / system growth areas • Reinforcement projects • Automated meter reading devices
Comprehensive	• All capital spending	• All capital spending

The most common application of General Purpose Capital Trackers is to provide for recovery of the costs associated with accelerated replacement of leak-prone distribution assets.[63] General Purpose Capital Trackers typically are designed to recover the revenue

62 There is also considerable recent experience in Canada and the U.S. related to non-traditional ratemaking approaches to offset the impact of declining delivery volumes on distribution revenues; and to allow for timely recovery of specific types or categories of expenses that are largely variable from year to year. However, these non-traditional ratemaking approaches are not directly relevant to EGD's 2nd Generation IR proposal.

63 Regulatory policies to promote accelerated replacement of leak prone assets are driven by public safety considerations in jurisdictions where leak-prone assets are a significant portion of total distribution mains and services.

requirement[64] associated with qualifying General Purpose facilities that are not reflected in the base distribution rates.[65] Annually, base distribution rates are increased by a special rate surcharge or by adjustments to base distribution rates to recover the General Purpose Capital revenue requirement. General Purpose Capital Trackers generally do not restrict the timing of the distribution company's next base rate case[66] and a General Purpose tracker mechanism may remain in effect for many years, depending on the duration of the General Purpose Capital program.[67]

Special Project Capital Trackers are generally used to recover the costs of large single projects of relatively short duration, such as major main extension projects, system improvement / reinforcement projects, and integrity management initiatives. The structures of Special Project and General Purpose Capital Trackers are very similar; typical Special Project Capital Trackers recover the revenue requirement[68] associated with the Special Project through annual increases to base distribution rates. Special Project Capital Trackers generally do not restrict the timing of the distribution company's next base rate case.[69] A Special Project tracker mechanism would usually remain in effect only until the distribution company's next base rate case, if the completed project is included in the rate case plant and rate base balances.

Lastly, Comprehensive approaches to recover the costs of all capital spending generally include (a) multi-year rate plans that account for the distribution company's (i) capital

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[64] The revenue requirement for a General Purpose Capital Tracker includes depreciation on the General Purpose Plant; return on the General Purpose net plant (total gross Plant less accumulated depreciation); income taxes and property taxes.

[65] General Purpose Trackers generally recover the costs of qualifying facilities that have placed into service, although some General Purpose Trackers provide for initial filings that include projected data, which is updated with actual data during the regulatory review period, prior to the approval of the general purpose increase in rates.

[66] However, a rate plan with a General Purpose Capital Tracker mechanism may also include a "stay out" provision.

[67] For example, even at an accelerated rate of replacement, some replacement programs may continue for 20 or more years. See, for example, National Grid Massachusetts, D.P.U. 10-55, November 2, 2010 Order, page 98.

[68] The revenue requirement for a Special Project Capital Tracker includes depreciation on the Special Project Plant; return on the Special Project net plant (total gross Plant less accumulated depreciation); income taxes and property taxes.

[69] However, a rate plan with a Special Project Capital Tracker mechanism may also include a "stay out" provision.

spending plans and (ii) projected expenses,[70] and (b) formulaic rate adjustments to recover annual revenue requirements, based on historical audited financial reporting.[71] These comprehensive multi-year rate plans provide annual rate adjustments for a specified period based on fixed annual revenue requirements that have been developed based on projected O&M expenses and projected plant and rate base, using a process that is often referred to as a "Building Blocks" methodology. The Building Block approach is discussed in more detail in the report on incentive ratemaking frameworks prepared for EGD by London Economics International LLC.

C. Assessment of EGD's Proposed Capital Recovery Approach

1. Introduction

The Capital Trackers listed in Figure 29 generally correspond to the rate setting approaches for the recovery of capital costs during the terms of electric IR plans that the Board has identified in the Renewed Regulatory Framework ("RRF") for Electricity (October 18, 2012). That is, (a) the Incremental Capital Module component of the 4th Generation IR is similar to (i) a General Purpose or (ii) a Special Project Capital Tracker, and (b) the Custom IR is similar to the Building Blocks-type Comprehensive ratemaking approach. The RRF Custom IR approach is also similar to EGD's proposed Customized IR plan.

To assess EGD's proposed approach to recover the costs of its projected capital spending, Concentric prepared analyses of EGD's projected 2014 to 2016 capital-related revenues and revenue requirements. Concentric calculated projected capital-related revenue requirements based on data provided by the Company. Projected revenues were developed for four scenarios; base case revenues were based on capital-related rebasing revenues with annual I-X revenue increases, and capital-related revenues for the three additional scenarios were based on I-X revenue increases, plus incremental revenue recovery produced by each of the three commonly-used capital recovery approaches. The four scenarios are summarized below:

Rate Option 1: I-X revenue per customer adjustment mechanism
Rate Option 2: General Purpose Capital Tracker, combined with an I-X revenue per customer adjustment mechanism

70 Multi-year rate plans have been approved for gas distribution companies in California and New York, and proposed by FortisBC.

71 These annual formulaic rate adjustments, commonly referred to as "revenue stabilization" adjustments, have been approved for gas distribution companies in Alabama, Georgia, Louisiana, Oklahoma, South Carolina, Texas, and Vermont.

Rate Option 3: Special Project Capital Tracker, combined with an I-X revenue per customer adjustment mechanism
Rate Option 4: Customized IR (EGD's Proposed Approach)

2. *Capital-Related Revenue Requirement and Revenues*

A utility's capital-related revenue requirement for a specific year includes (1) return of investment in plant (depreciation), (2) return on investment in plant, and (3) taxes. As explained in Section VII.B, the components of the capital-related revenue requirement for a specific year - depreciation expense, return on investment in plant[72], and taxes - are based on (a) plant and rate base records and (b) certain factors, such as depreciation rates, tax rates, and rate of return on rate base, which are generally reviewed by regulators during a rebasing or traditional COS proceeding. Changes in the capital-related revenue requirements from year-to-year are caused by changes in plant in service and changes in rate base.[73]

Capital-related revenues are initially set by the regulators in a rebasing or traditional COS proceeding based on the regulator's determination of the capital-related revenue requirement that reflects the utility's on-going costs of providing service. Annual changes in a utility's capital-related base distribution revenues, relative to the allowed revenues in the utility's most recent rebasing or COS proceeding, reflect (a) changes in the total billing units – fixed, volumetric and demand – that are charged to the utility's customers and (b) changes in rates as provided for in the utility's rate plan.

3. *Concentric's Capital-related Revenue and Revenue Requirement Models*

For each of the four Rate Options listed in Section VII.C.1, Concentric calculated projected 2014 to 2016 capital-related revenues and revenue requirements.

EGD's annual revenue requirements were calculated according to the following Equation 1:

$$\text{Revenue Requirement}_{\text{year i}}^{\text{Plant-related}} = \text{ROR}^{\text{pretax}} \text{ x Rate Base}_{\text{year i}} + \text{Depreciation Expense}_{\text{year i}} \qquad \text{[Equation 1]}$$

72 Return on investment is the product of (a) allowed return and (b) rate base; rate base is the total original value of plant in service, reduced by the accumulated depreciation on the plant in service.

73 Changes in plant result from additions to plant, net of plant retirements. Changes in rate base result from additions to plant, net of retirements and changes in accumulated depreciation.

Where:

$$year_i = (2014, 2015, 2016)$$

$$\text{ROR}^{\text{pretax}} = Allowed\ Weighted\ Average\ Cost\ of\ Capital, before\ taxes$$[74]

$$RateBase_{year\ i} = Plant_{year\ i} - Accumulated\ Depreciation_{year\ i}$$

$$\text{Depreciation Expense}_{\text{year i}} = Plant_{year\ 1}\ x\ Depreciation\ Rate_{year\ i}$$

EGD's annual revenues (not including incremental Capital Recovery revenues associated with Rate Options 2 and 3) were calculated according to the following Equation 2[75]:

$$Revenues_{year\ i} = RevReq_{Rebasing}^{Plant-related}\ x\ \left(1 + P_{year\ i}\right)\ x\ \left(1 + G_{year\ i}\right) \qquad \text{[Equation 2]}$$

Where:

$$year_i = (2014, 2015, 2016)$$

$$\begin{aligned} RevReq_{Rebasing}^{Plant-related} \\ &= ROR^{pretax}\ x\ Rate\ Base_{Rebasing} \\ &+ Plant_{Rebasing}\ x\ Combined\ Depreciation\ Rate \end{aligned}$$

$$\begin{aligned} P_{year\ i} = {} & Percent\ increase\ in\ revenue\ per\ customer\ cap, \\ & determined\ according\ to\ projected\ values\ in\ year\ i\ for\ I\ and\ X \end{aligned}$$

$$G_{year\ i} = Percent\ increase\ in\ projected\ number\ of\ customers\ in\ year\ i$$

Concentric's Capital-related Revenue and Revenue Requirement models do not include (a) taxes on depreciation expense or (b) property taxes. Concentric, with advice from the Company related to Canadian tax issues, determined that excluding the tax effect on depreciation from both the revenue and revenue requirement calculations would not have a significant impact on the model results, and would simplify the model calculations. Concentric and the Company similarly determined that excluding property taxes from both

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74 $\text{ROR}^{\text{pretax}}$ for EGD is calculated by dividing Allowed weighted average cost of capital, after taxes by (1 – the combined effect of federal and provincial tax rates)

75 Rate Option 2, incremental General Purpose Capital revenue calculations are shown in Figure 32, lines 17 to 29; Rate Option 3 incremental Special Project Capital revenue calculations are shown in Figure 34, lines 16 to 22 and Rate Option 4 Customized Capital revenue calculations are shown in Figure 36, line 10.

the revenue and revenue requirement calculations would not materially impact the model results.

The Company provided rebasing and 2014 to 2016 data for plant, rate base, depreciation rates, income tax rates, cost of capital, and accumulated depreciation. EGD also provided estimates of the rate of growth in customers from 2014 to 2016. The projected I-X revenue increases are based on Concentric's X factor (Section IV) and I Factor (Section V) recommendations.

4. *Model Results*

a. Rate Option 1: I-X

Figure 30 provides Concentric's analysis of EGD's projected 2014 to 2016 capital-related revenue requirements, I – X revenues, and revenue deficiencies if EGD rates were increased annually from 2014 to 2016 by the I-X escalation formula, with no additional mechanism to recover incremental capital costs.

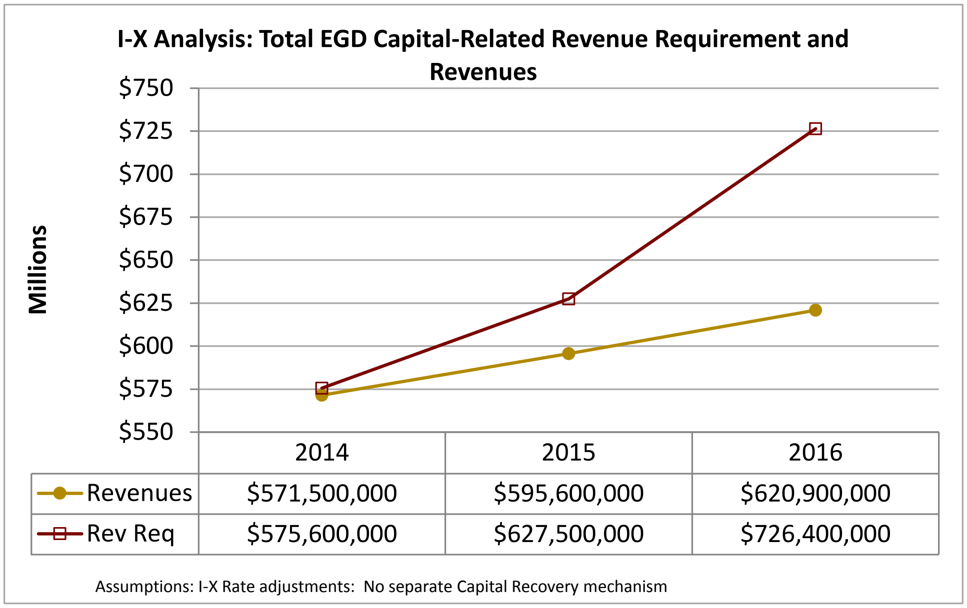
Figure 30 Rate Option 1: Revenues based on I-X rate adjustments

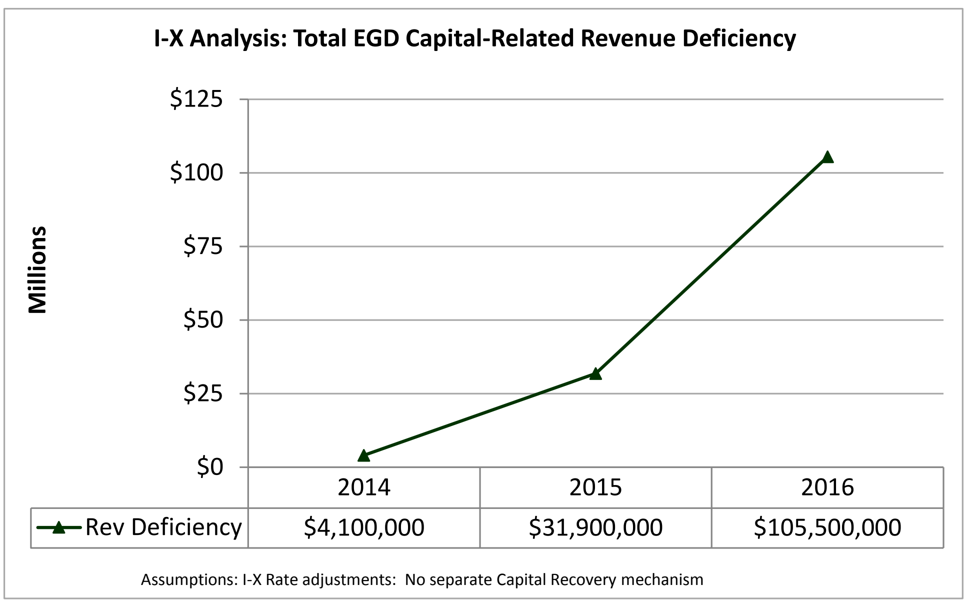
		2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$6,977,000,000	$7,441,000,000	$8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return - DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15				
16	$Revenues^{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
17				
18	Deficiency (Surplus) in Revenues	$ 4,100,000	$ 31,900,000	$ 105,500,000

Figure 31 provides a graphical representation of the Rate Option 1 capital-related revenues, revenue requirements and revenue deficiencies.

It is Concentric's assessment that Figures 30 and 31 demonstrate that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year capital-related revenue deficiency is $141.5 million.

Figure 31: Rate Option 1: Revenues, Revenue Requirement, and Revenue Deficiency





b. Rate Option 2: I-X plus General Purpose (ICM-type) Capital Tracker

For the Rate Option 2 analysis, Concentric modeled the General Purpose tracker using the Ontario 3rd and 4th Generation Electric ICM Threshold formulas. Figure 32 provides Concentric's analysis of EGD's projected 2014 to 2016 capital-related revenue requirements, I

– X plus ICM revenues, and revenue deficiencies if EGD rates were increased annually from 2014 to 2016 by the I-X escalation formula, with additional revenues to recover plant additions above a threshold level.[76]

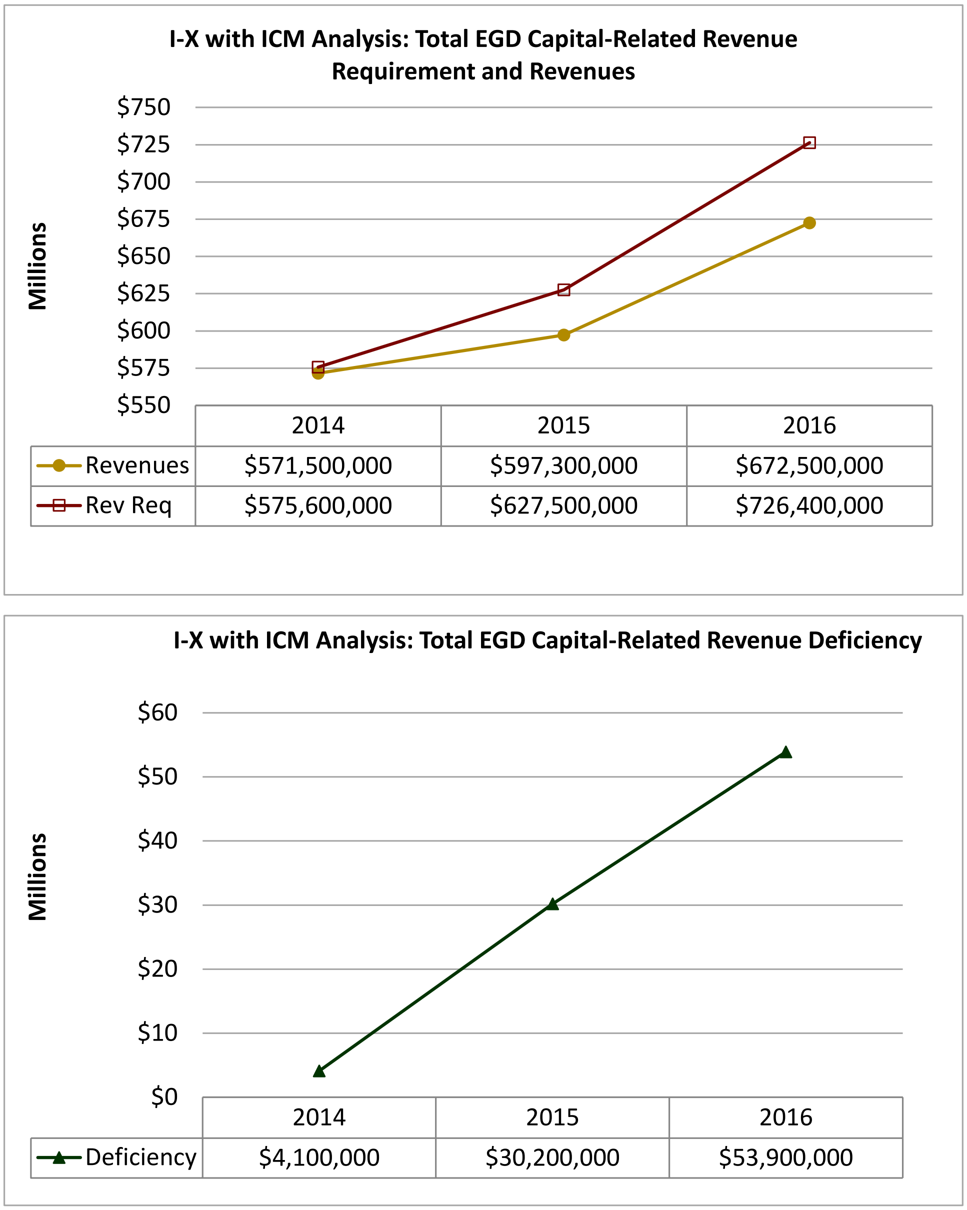
Figure 32: Rate Option 2: Revenues based on I-X and General Purpose Capital Tracker

		2014	2015	2016
1	Revenue Requirement			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	RORPretax	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return - DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15	I-X Revenues$^{\text{Plant-related}}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
16				
17	**THRESHOLD CALCULATION** $Threshold = 1.2\ x\ DeprExp_{rebasing} + Rate\ Base_{rebasing}\ x\ (P + G + PxG)$			
18	(G + P + P x G)	4.173%	4.222%	4.237%
19	$Rate\ Base_{Rebasing}\ x\ (G + P + GxP)$	$ 162,300,000	$ 164,200,000	$ 164,800,000
20	$1.2\ x\ DeprExp_{rebasing}$	$ 284,800,000	$ 284,800,000	$ 284,800,000
21	Threshold	$ 447,100,000	$ 449,000,000	$ 449,600,000
22				
23	Plant Additions	$ 218,400,000	$ 463,900,000	$ 880,900,000
24	Plant Additions above Threshold	$ -	$ 14,900,000	$ 431,300,000
25	Total Plant Above Threshold	$ -	$ 14,900,000	$ 446,200,000
26	Depreciation	$ -	$ 500,000	$ 15,600,000
27	Accumulated Depreciation	$ -	$ 500,000	$ 16,100,000
28	Rate Base above Threshold	$ -	$ 14,400,000	$ 430,100,000
29	ICM Revenues	$ -	$ 1,700,000	$ 51,600,000
30				
31	Total Revenues	$ 571,500,000	$ 597,300,000	$ 672,500,000
32	Deficiency (Surplus) in Revenues	$ 4,100,000	$ 30,200,000	$ 53,900,000

76 The ICM Threshold calculations are shown in Figure 34, lines 17 to 21.

Figure 33 provides a graphical representation of the Rate Option 2 capital-related revenues, revenue requirements and revenue deficiencies.

Figure 33: Rate Option 2: Revenues, Revenue Requirement, and Revenue Deficiency



It is Concentric's assessment that Figures 32 and 33 demonstrate that an I-X escalation formula combined with an ICM-type mechanism does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year capital-related revenue deficiency is $88.2 million.

c. Rate Option 3: I-X plus Special Project Capital Tracker

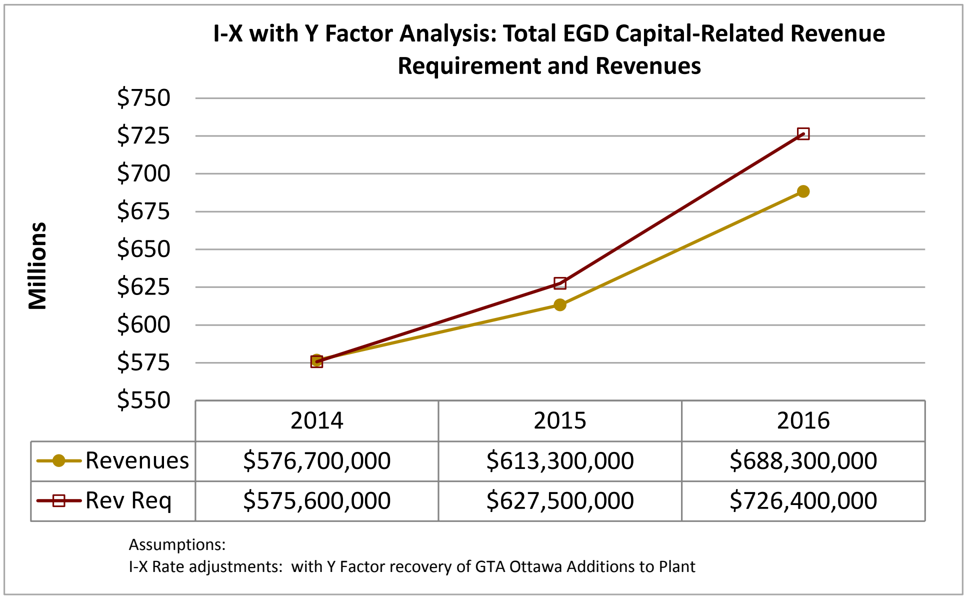
For the Rate Option 3 analysis, Concentric modeled the Special Project tracker on a Y Factor type capital recovery mechanism that recovers the revenue requirements associated with the Company's Ottawa and GTA reinforcement projects. Figure 34 provides Concentric's analysis of EGD's projected 2014 – 2016 capital-related revenue requirements, I – X plus Y Factor revenues, and revenue deficiencies if EGD rates were increased annually during the 2014 to 2016 period by the I-X escalation formula, with additional Y Factor revenues.

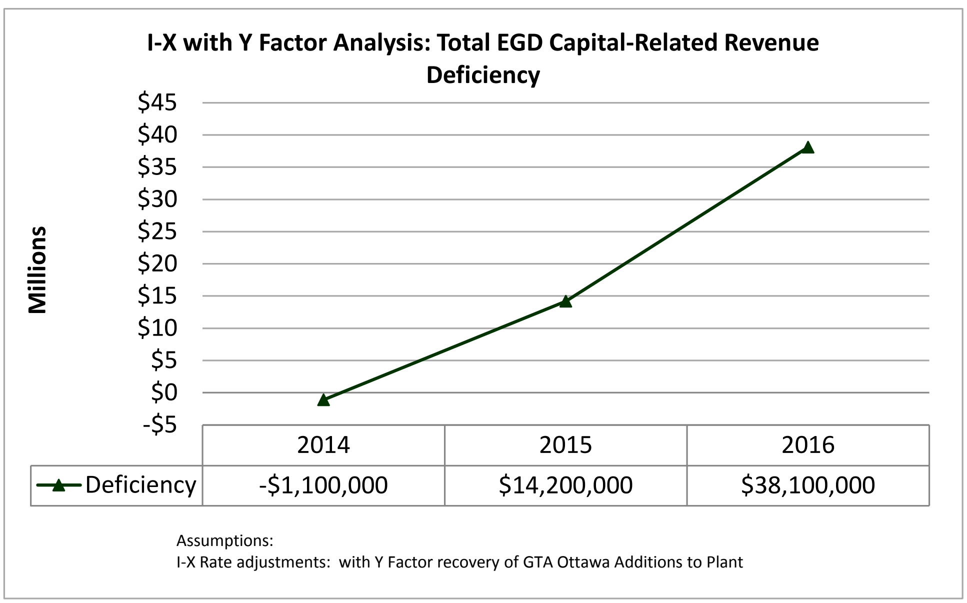
Figure 34: Rate Option 3: Revenues based on I-X plus Special Project Capital Tracker

		2014	2015	2016
	Revenue Requirement			
2	Average of Monthly Avgs Plant	$ 6,977,000,000	$ 7,441,000,000	$ 8,321,900,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return - DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Rebasing Return	$ 311,300,000	$ 311,300,000	$ 311,300,000
11	Rebasing Depreciation Expense	$ 237,300,000	$ 237,300,000	$ 237,300,000
12	P (Percent increase in Rates)	2.45%	2.45%	2.45%
13	G (Percent increase in Customers)	1.69%	1.73%	1.75%
14	(1 + P) x (1 + G)	1.04173	1.08571	1.13171
15	I-X $Revenues^{Plant\text{-}related}$ = [Rebasing Return + Depreciation] x (1+P) x (1+G)	$ 571,500,000	$ 595,600,000	$ 620,900,000
16	GTA, Ottawa Plant	$ 48,900,000	$ 172,100,000	$ 631,900,000
17	Depreciation Rate	2.66%	2.21%	2.47%
18	GTA, Ottawa Depreciation Expense	$ (1,300,000)	$ (3,800,000)	$ (15,600,000)
19	GTA, Ottawa Rate Base ("RB")	$ 48,400,000	$ 169,900,000	$ 619,100,000
20	ROR^{Pretax}	7.98%	8.19%	8.36%
21	GTA, Ottawa Return: ROR Pretax x RB	$ 3,900,000	$ 13,900,000	$ 51,800,000
22	GTA, Ottawa Revenue Requirement	$ 5,200,000	$ 17,700,000	$ 67,400,000
23	Total Revenues (I-X plus Y Factor)	$ 576,700,000	$ 613,300,000	$ 688,300,000
24				
25	Revenue Deficiency (with I-X and Y Factor)	$ (1,100,000)	$ 14,200,000	$ 38,100,000

Figure 35 provides a graphical representation of the Rate Option 3 revenues, revenue requirements and revenue deficiencies.

Figure 35: Rate Option 3: Revenues, Revenue Requirement, and Revenue Deficiency





It is Concentric's assessment that Figures 34 and 35 demonstrate that an I-X escalation formula combined with Y Factor Recovery of the GTA and Ottawa projects does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $51.2 million.

d. Rate Option 4: Customized IR (EGD's Proposed Approach)

The modeling for the capital-related revenues and revenue requirements for EGD's proposed Customized IR is straight-forward: the capital-related revenues are projected to be equal to the capital-related revenue requirement. Figure 36 provides Concentric's analysis of EGD's projected 2014 – 2016 capital-related revenue requirements and Customized IR revenues.

Figure 36: Rate Option 4: Revenues based on EGD's Proposed Customized IR Approach

		2014	2015	2016
1	**Revenue Requirement**			
2	Average of Monthly Avgs Plant	$ 6,976,900,000	$ 7,440,900,000	$ 8,321,800,000
3	Depreciation Rate	3.58%	3.55%	3.50%
4	Depreciation Expense ("DeprExp")	$ (250,100,000)	$ (263,900,000)	$ (291,200,000)
5	Average of Monthly Avgs Rate Base	$ 4,081,300,000	$ 4,440,400,000	$ 5,203,200,000
6	ROR^{Pretax}	7.98%	8.19%	8.36%
7	Return: ROR Pretax x RB	$ 325,500,000	$ 363,600,000	$ 435,200,000
8	Revenue Requirement: Return + DeprExp	$ 575,600,000	$ 627,500,000	$ 726,400,000
9	**Revenues**			
10	Total Revenues (Customized IR)	$ 575,600,000	$ 627,500,000	$ 726,400,000

5. Summary

EGD's opportunity to earn a reasonable return is a key consideration in the overall assessment of IR ratemaking options, and Concentric's analysis of EGD's Capital-related revenues and revenue requirements for each of the four ratemaking options is a primary factor that will affect EGD's opportunity to earn a reasonable return[77]. Figure 37 demonstrates that three of the commonly used capital recovery ratemaking options would create capital-related revenue deficiencies of at least $51.2 million and as much as $141.5 million over the 2014 to 2016 period. Considering capital-related revenues and revenue requirements, only the Customized IR approach would provide EGD with a reasonable opportunity to earn a fair return.

[77] Concentric's overall evaluation of EGD's proposed IR plan, which takes into account several other factors, in addition to Capital-related revenues and revenue requirements, is provided in Section IX.

Figure 37: Summary of Capital Recovery Options Revenue Deficiencies

		Revenue Deficiencies			
		2014	2015	2016	3 Year Total
1	Rate Option 1: I-X	$ 4,100,000	$ 31,900,000	$105,500,000	$141,500,000
2	Rate Option 2: I-X plus ICM	$ 4,100,000	$ 30,200,000	$ 53,900,000	$88,200,000
3	Rate Option 3: I-X plus Y Factor	$ (1,100,000)	$ 14,200,000	$ 38,100,000	$51,200,000
4	Rate Option 4: Customized IR	$ -	$ -	$ -	$ -

VIII. EARNINGS SHARING MECHANISM ("ESM")

A. Introduction

EGD asked Concentric to review EGD's proposed ESM and provide our perspective regarding the reasonableness of EGD's proposed ESM, given the overall structure of EGD's proposed program. This section provides an overview of ESMs based on our experience, and our evaluation of EGD's proposed ESM.

Generically, an ESM is a ratemaking tool that provides for sharing between customers and shareholders of earnings that are either above or below the level of earnings that would produce the authorized return on equity ("ROE"). Customer rates are adjusted either downward (when there are surplus earnings) or upward (when there is an earnings shortfall) to account for the customer portion of the earnings that are to be shared.

ESMs often incorporate a "deadband" around the authorized ROE within which the utility absorbs 100% of the variance in earnings; there is no customer sharing within the deadband. Sharing occurs when earnings fall outside of the deadband; this earnings surplus or shortfall is shared between the utility and its customers according to prescribed proportions (e.g., 50% to the utility; 50% to customers).

B. Evaluation of EGD's Proposed ESM

Concentric understands that EGD is proposing an ESM with a deadband of 100 basis points above the authorized ROE (updated annually according to the approved formula), the same as that approved for EGD's 1st Generation IR Plan. If the actual, weather normalized, ROE exceeds the authorized ROE by more than 100 basis points; the excess will be split evenly between customers and the Company. Earnings more than +/- 300 basis points above/below the authorized ROE would trigger a regulatory review of the IR plan.

EGD's proposed ESM is consistent with the structure of ESMs employed elsewhere in Canada and the U.S., although there are many variations to the basic structure. Four important elements to consider are the size of the deadband, the sharing mechanism, whether the mechanism is symmetrical or not, and the re-opener provisions.

The size of the deadband is an important design element because it can affect management's incentives to pursue efficiencies. As the size of the deadband increases, management has an increased incentive to pursue efficiency gains because the utility retains a greater proportion of the benefits. Some ESMs do not have deadbands at all (i.e., sharing begins with the first dollar in excess of or below the allowed ROE) although this is less common. EGD's proposed deadband of 100 basis points is consistent with industry norms. Since it is based on weather normalized earnings, volatility related to weather is addressed elsewhere, which reduces the likelihood that earnings would fall outside the deadband. We would note, for the Board's consideration, that a larger ESM deadband would increase the Company's incentive to identify and implement incremental efficiency gains.

There are a variety of sharing proportions that are employed by North American utilities although 50-50, 75-25, and 25-75 (utility and customer proportions respectively) are the most common. Some ESMs have tiered sharing formulas, i.e., the sharing proportions are adjusted in tiers as earnings deviate further from the authorized ROE. Tiered formulas tend to have customer-sharing percentages that increase as earnings increase above the authorized ROE. EGD's proposed 50-50 sharing with customers above the deadband is a relatively common approach, and conveys a sense of equity between the company and its customers.

In some ESMs, both earnings surpluses and shortfalls are shared according to identical structures ("symmetrical ESMs"), while others apply different structures to surpluses and shortfalls ("asymmetrical ESMs"). The argument for symmetrical ESMs is that they balance the risk and reward prospects for the utility and customers. ESMs are most prevalent when there is a multi-year rate plan that precludes the utility from filing a rate case except under extraordinary circumstances, such as IR. As the term of a multi-year rate plan increases, there is a greater likelihood that revenues and/or expenses will deviate in ways that may not have been anticipated when the plan was approved. The ESM helps safeguard against an earnings outcome that may be unacceptable to either customers (or regulators on their behalf) or to the utility. In this respect, ESMs are a form of earnings variance management for the regulator. However, rather than focus narrowly on a particular revenue or expense circumstance that contributes to the variation in earnings, the ESM is designed to focus on the end result and thus captures all such contributing circumstances in a single measure. Since it is unknown whether the potentially unanticipated earnings deviations will be positive or negative, even-handed regulatory policy would suggest that it is appropriate to provide symmetrical safeguards for customers and the utility. While symmetrical ESMs balance the risk and reward prospects for the utility and customers, it is also common for ESMs to be asymmetrical. One example of an asymmetrical program is EGD's 1st Generation IR Plan.

Lastly, it is appropriate to include re-opener provisions[78] as part of EGD's ESM to protect against significant unanticipated results. Re-opener provisions are common in IR plans as an important safeguard to provide the company and the regulator the opportunity to re-evaluate

[78] Similarly, it is also appropriate to allow for Z Factors, to recover from customers or pass back to customers large unanticipated changes in costs that are outside of EGD's control.

the IR plan and determine what features are causing the significant deviation in earnings and determine whether plan features need to be modified, or whether the IR plan should be abandoned. It is important that the re-opener trigger circumstances be significant enough to prevent re-openers for minor to moderate deviations in earnings as constant re-openers would dampen the benefits if multi-year IR plans. It is also important that the re-opener threshold not be so extreme that the utility has the opportunity to enjoy significant over earnings at customers' expense or that the utility's financial future is placed at risk due to significant earnings shortfalls. Concentric believes that EGD's re-opener trigger of +/- 300 basis points in any year achieves a reasonable balance between allowing the IR plan to continue uninterrupted and providing a safeguard to address unanticipated circumstances. Furthermore, the symmetrical nature of EGD's re-opener trigger provides protection for both customers and EGD.

On balance, we conclude that EGD's proposed ESM provides an appropriate safeguard for customers and the utility. The deadband serves the purpose of incenting EGD to identify additional efficiencies, while the earnings sharing and re-opener trigger provide a safety mechanism to address large deviations in earnings. While we could argue that a 100 basis point deadband creates a diminished incentive compared to a wider deadband, and that a symmetrical ESM would better balance the risk and reward profiles of EGD and customers, EGD's performance under the 1st Generation IR (with the same ESM parameters) suggests that these issues are manageable, as customers benefited from earnings sharing in all 5 years of the Plan. Based on our research and industry experience, Concentric believes that EGD's ESM proposal is reasonable.

IX. EVALUATION OF EGD'S PROPOSED IR PLAN

As discussed in the foregoing report, Concentric has evaluated the proposed Enbridge Customized IR plan based on our regulatory and industry research, quantitative analysis, and knowledge of other programs in North America. We have assessed the proposed plan from two primary perspectives:

- Consistency with Ontario and North American regulatory principles and practice;
- Quantitative assessment of Enbridge's operational efficiency and projected revenue vs. I-X rate paths.

A. Consistency with Regulatory Principles and Practice

The following criteria, as specified in the Company's evidence and taken from the Board's Natural Gas Forum and the Ontario Energy Board Act, present a reasonable set of standards by which to judge the proposed plan. Specifically, does the plan:

a) Ensure appropriate reliability and quality of service (including safe operations);

b) Protect customers from unreasonable price impacts;

c) Promote energy conservation and efficiency;

d) Protect the financial viability of the distributor and allow for appropriate investments to be made; and

e) Provide a framework that incents the distributor to implement sustainable efficiency improvements?

On these points, reliability and quality of service are protected through adequate funding of both O&M and capital budgets, and through service quality monitoring over the course of the plan. Customers are protected from unreasonable price impacts through "testing" the existing cost structure of Enbridge against industry peers, and the projected rate path against that for an industry peer group based on the combination of benchmarking and productivity studies. Conservation and energy efficiency are promoted through ongoing funding of DSM programs. The financial viability of the Company is not guaranteed, but placed in the hands of management who must operate within the "fixed" revenue structure in order to fully recover costs and earn the allowed return. Capital plans are scrutinized in this hearing process, and in Leave to Construct proceedings on major projects. Efficiency improvements are incentivized through (1) a revenue path based on Enbridge's peers, (2) an earnings sharing mechanism, and (3) a sustainable efficiency incentive mechanism.[79] In principle and in design, the overall plan proposed by Enbridge addresses these standards.

Moving beyond Ontario specific standards, we also find the proposal consistent with trends we see elsewhere, where regulators have turned to more flexible models of incentive regulation designed around specific utility circumstances. This plan follows a similar evolution for Enbridge, while still testing the plan against the more formulaic I-X approach.

B. Quantitative Evaluation

To test the reasonableness of EGD's Allowed Revenue amounts, Concentric performed several related evaluations. Concentric compared EGD's forecast O&M cost per customer to EGD's historical trend of O&M costs per customer. EGD's projected O&M cost per customer is higher than recent history, but not by a significant amount. Concentric also compared EGD's forecasted O&M cost per customer with the O&M cost per customer that would be derived from an I-X formula. The results of Concentric's analyses indicate that EGD's projected O&M costs are reasonable based on a comparison to the benchmark utilities, and in relation to the industry analysis of O&M productivity.

Concentric expanded the analysis to consider capital. The quantitative analysis for Concentric's assessment of EGD's proposed capital cost recovery approach is based on the results of models that Concentric developed to determine the capital-related revenue requirements and revenues under alternative rate recovery mechanisms. It is Concentric's assessment that an I-X escalation formula does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $141.5 million. An I-X escalation formula combined with an ICM-type mechanism also does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $88.2 million. Further, an I-X escalation formula combined with Y Factor Recovery of the GTA and Ottawa projects does not provide adequate recovery of capital-related costs during the 2014 to 2016 period. The cumulative three year revenue deficiency is $51.2 million. Only Rate Option 4, a Customized IR plan with recovery of capital-related costs matched to EGD's projected capital-related revenue requirements, adequately covers the costs of EGD's base capital spending and GTA and Ottawa reinforcement projects.

These analyses are summarized in the following figures that contrast the total revenue recovered under two alternative rate recovery alternatives (I-X, and I-X plus Y factors for the

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[79] Enbridge's Sustainable Efficiency Incentive Mechanism is described in Exhibit A2, Tab 11, Schedule 3.

GTA and Ottawa projects) versus Enbridge's projected O&M and capital Allowed Revenue amounts. The first figure illustrates the estimated total revenue collected for O&M and capital vs. projected costs on a per customer basis, and the second figure aggregates these into total dollars. The differences between forecasted revenue and the rate recovery mechanism are revenue shortfalls or surpluses. The I-X rate option leads to the largest shortfall, of $126 million; the I-X plus Y factor option produces a lower deficiency, of $35.7 million, but is still inadequate to provide full cost recovery, even with embedded efficiencies.

Figure 38: O&M Plus Capital Cost/Customer

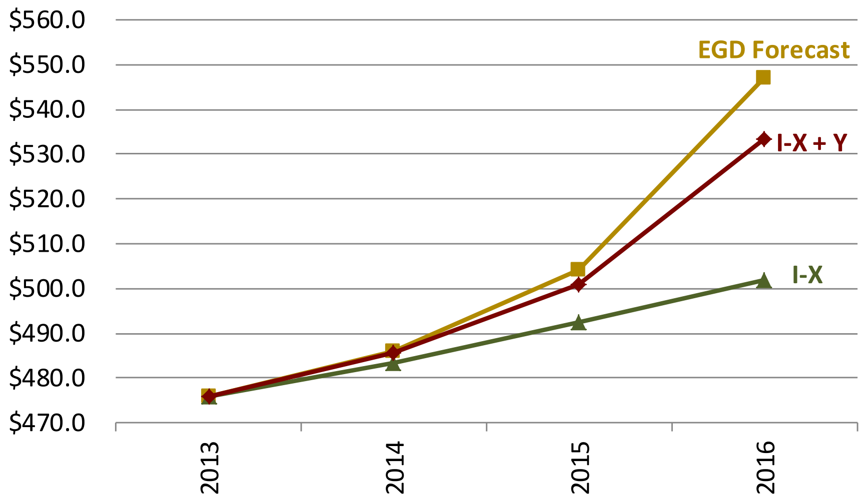
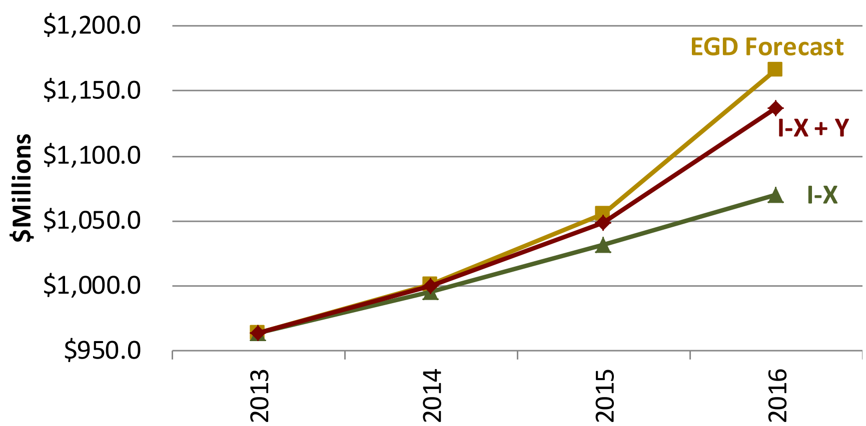


Figure 39: O&M Plus Capital Cost



C. Conclusion

Based on our analysis, research and industry experience, Concentric believes that EGD's overall proposed Customized IR proposal is reasonable. The proposed Customized IR approach is the only mechanism evaluated that tracks costs (including the larger than normal capital investment), while providing Enbridge with a built-in challenge for continued productivity improvement. On balance, we conclude that EGD's proposed plan provides an appropriate safeguard for customers and the utility, and meets to Board's goals for incentive regulation while allowing the company a reasonable opportunity to earn a fair return.

APPENDIX A: BENCHMARKING - 2011 UPDATE

I. INTRODUCTION

Enbridge Gas Distribution ("Enbridge", "EGD", or the "Company") retained Concentric Energy Advisors, Inc. ("Concentric") in 2011 to provide a perspective on Enbridge's performance relative to its peers during the 1st Generation Incentive Regulation ("IR") plan period. That benchmarking analysis measured EGD against both a US and Canadian peer group for the years 2009 and 2010 using a series of metrics designed to examine the relative efficiency of the Company in terms of both its capital investment and O&M expense profile. The benchmarking study also included trend analyses covering the 2000 to 2010 period. The benchmarking study was submitted in EGD's rebasing case, EB-2011-0354, Exhibit A2, Tab 1, schedule 2.

This current study is an update to the original filed benchmarking study. This update relies on the same methodology, data sources, and U.S. peer group as the original benchmarking study, but now incorporates 2011 data.[80] To review, the 28 company industry peer group was based on U.S. companies that have similar operations (i.e., natural gas utilities), similar weather (i.e., in the northern half of the U.S.), and similar size (i.e., at least 500,000 customers) as EGD. Canadian companies were included in the original benchmarking analysis for 2009; however, due to the difficulty obtaining consistent, reliable data Canadian companies were not included in the 2011 update.

Data for EGD was provided by the Company. Data for the U.S. peer group was primarily compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports").

II. INDUSTRY BENCHMARKING RESULTS

A. Peer Group Analysis

Enbridge's performance is compared to a peer group of 28 U.S. natural gas utilities that were chosen for the original analysis based on a number of selection criteria designed to reflect Enbridge's operating profile and provide a broad perspective for industry comparisons. In order to provide proper context and background on the peer group, the following sections compare Enbridge's operational profile in 2011 to the U.S. peer group.

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80 During the update to include 2011 data, a few historical data points were revised based on additional information becoming available. These revisions did not change the results in any meaningful way.

1. *Customer Profile*

In terms of utility size as measured by the number of customers, Enbridge is the third largest overall in the peer group. Figures A-1 and A-2 show the total natural gas customers and percentage residential customers in 2011 for Enbridge and each of the natural gas utilities in the U.S. peer group. As shown in the graphs, Enbridge serves almost 2 million customers, with residential customers representing over 90% of Enbridge's customer count.

Figure A-1: Total 2011 Natural Gas Customers
(Sales & Transportation, excludes Resale Customers)

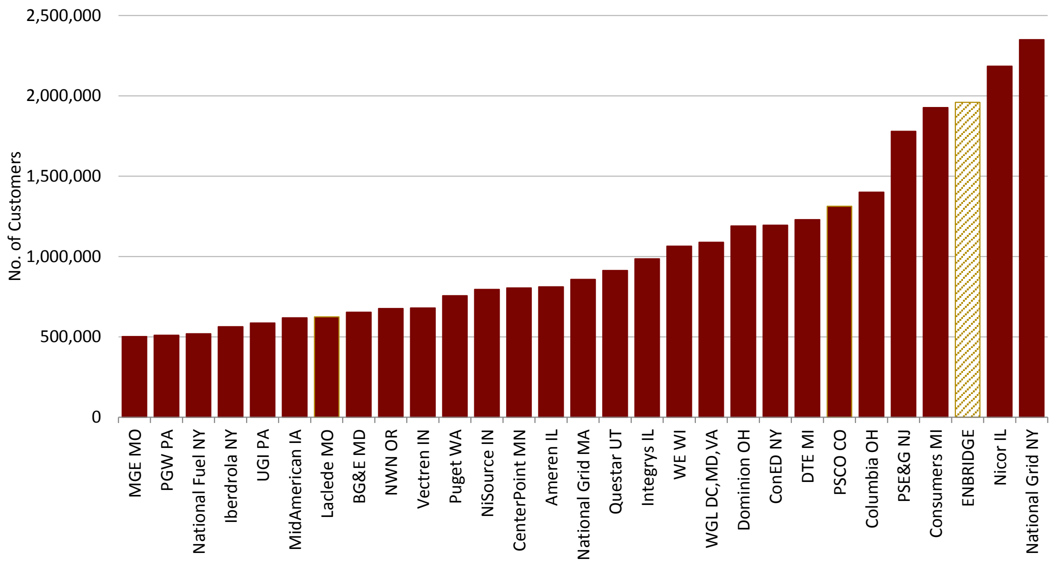
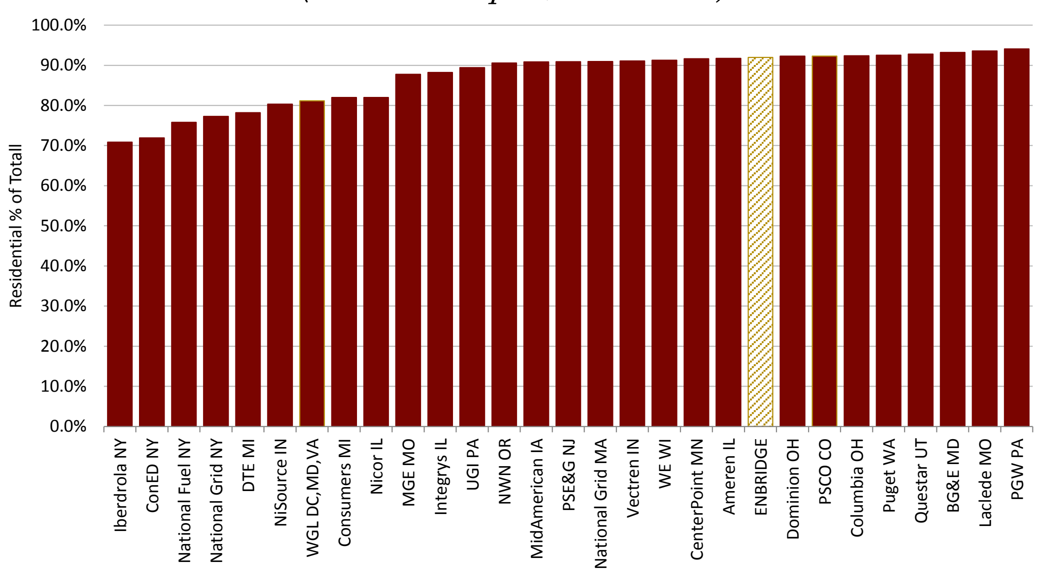


Figure A-2: 2011 Residential Customers as % of Total Natural Gas Customers
(Sales & Transport, excl. Resale)



2. *System Throughput*

Figures A-3 and A-4 show the total natural gas volumes and percentage residential volumes in 2011 for Enbridge and each of the natural gas utilities in the peer group. As illustrated, Enbridge is the third largest utility compared to the U.S. peer group based on total natural gas volumes. Although Enbridge's customer profile is predominantly residential, in terms of its system throughput, residential volumes represent less than 40% of Enbridge's total natural gas volumes, which is in the second lowest quartile in 2011. As shown in Figure A-5, Enbridge is in the top quartile in terms of natural gas volumes per customer.

Figure A-3: Total 2011 Natural Gas Volumes
(Sales & Transportation, excludes Resale Volumes)

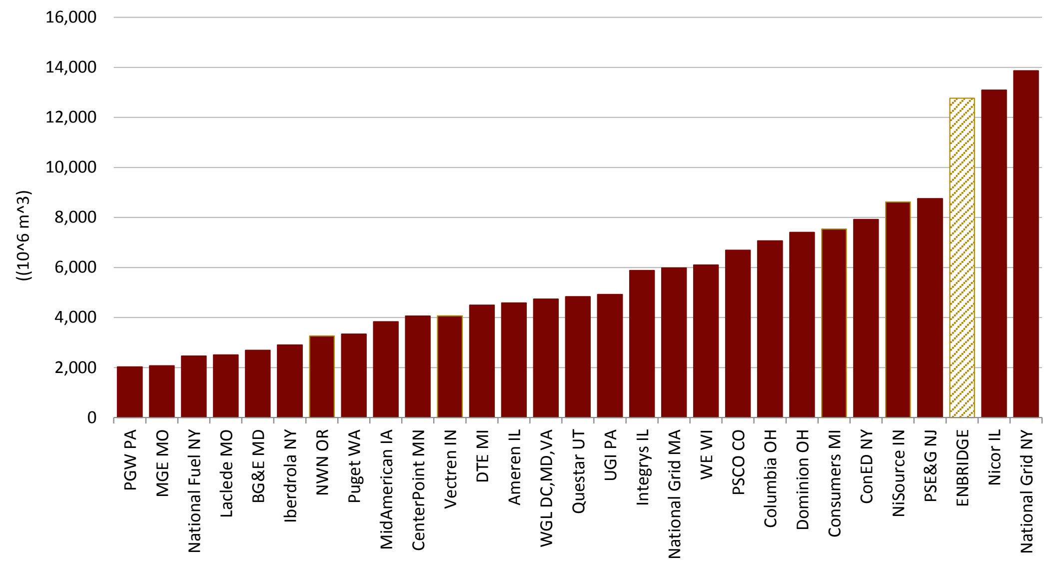


Figure A-4: 2011 Residential Volumes as % of Total Natural Gas Volumes (Sales & Transport, excl. Resale)

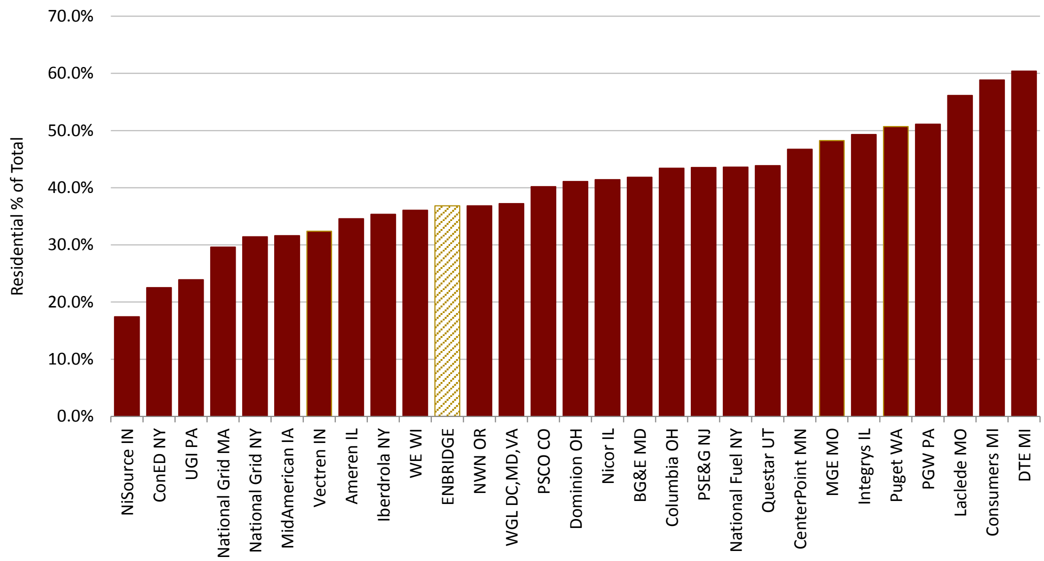
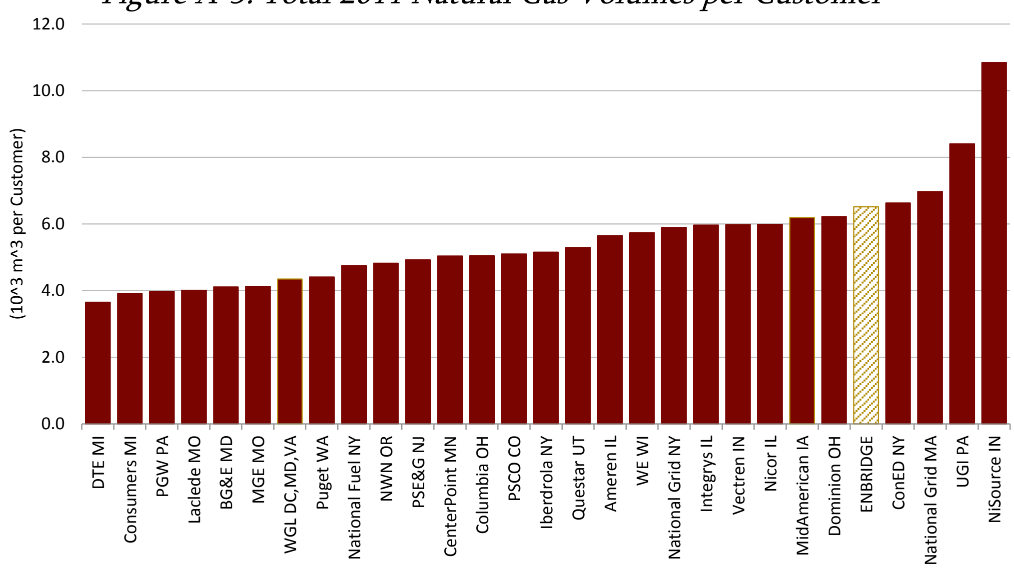


Figure A-5: Total 2011 Natural Gas Volumes per Customer



3. Customer Density

Figures A-6 and A-7 show the customer density (i.e., number of customers per kilometer of distribution main), as well as natural gas volumes per kilometer of distribution main in 2011 for Enbridge and each of the natural gas utilities in the peer group. Enbridge is in the top quartile for density. All else being equal, density is a favorable attribute for the cost of serving gas customers.

Figure A-6: 2011 Natural Gas Customers per Kilometer of Distribution

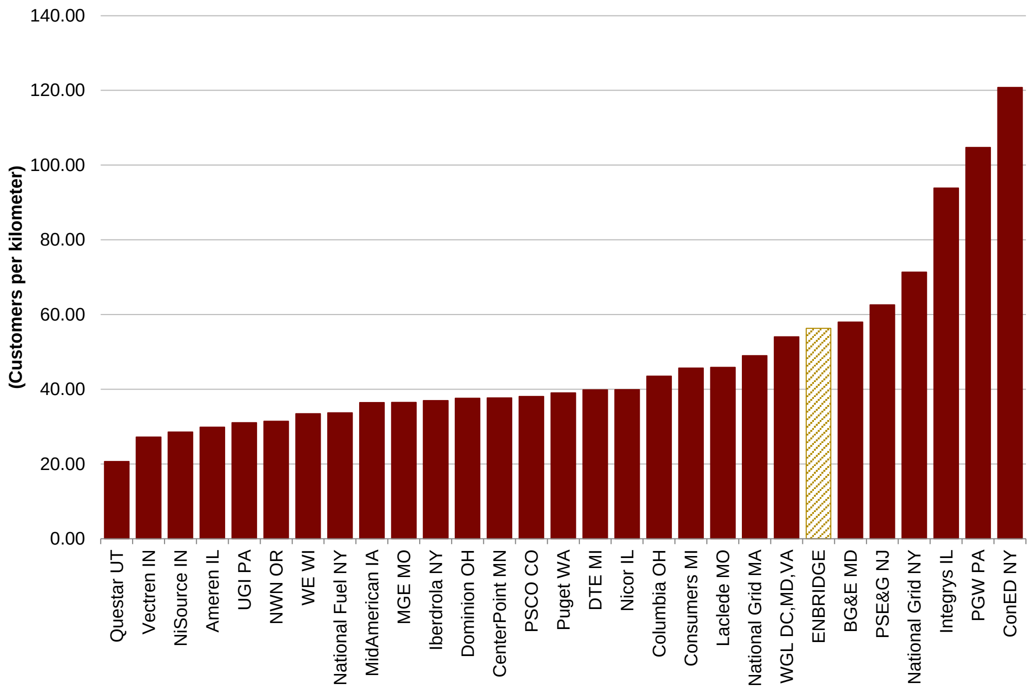
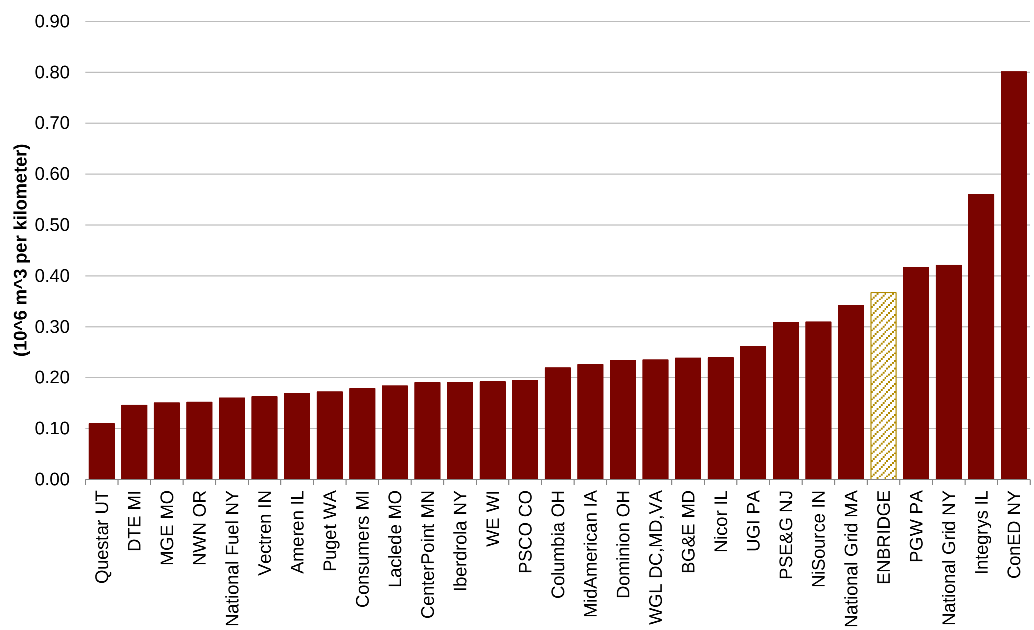


Figure A-7: 2011 Natural Gas Volumes per Kilometer of Distribution Main



Overall, Enbridge is above average in terms of size and density as compared to the peer group, but is within the range of peer group results, indicating that the peer group is appropriate for general benchmarking purposes.

B. Benchmarking and Trend Analysis

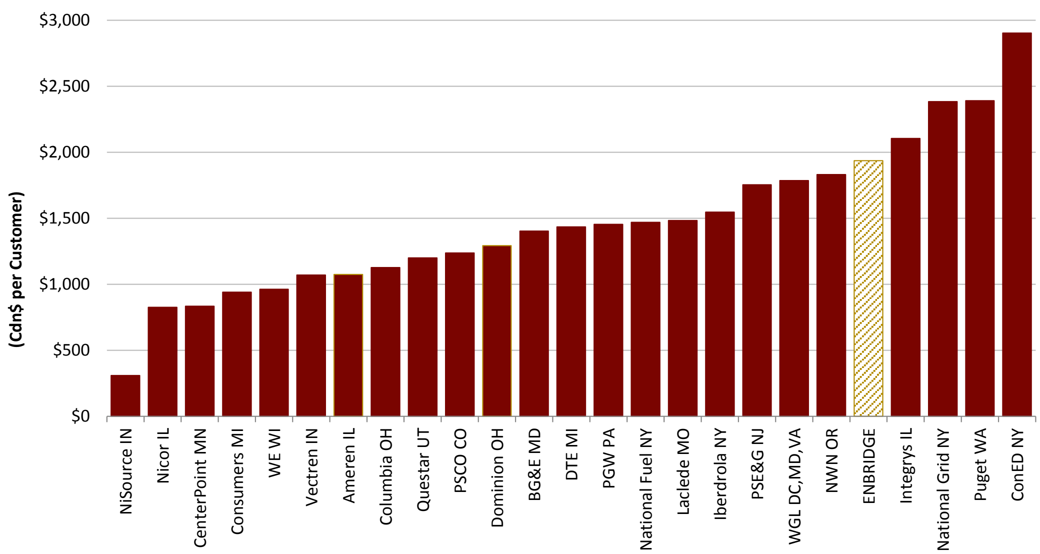
The following sections summarize the results of the benchmarking and trend analysis which compares Enbridge's performance against the peer group across a number of operational metrics. Enbridge's performance in 2011 is benchmarked against the U.S. peer group. In addition, Enbridge's longer-term performance trends are compared to the performance trends of the U.S. peer group over the 2000 to 2011 time period.

1. Net Plant per Customer and per Unit of Volume

The total net plant, as shown in the charts below, includes transmission, storage, distribution, and an allocated portion of general plant costs. Enbridge's total net plant per customer in 2011 is approximately $1,900 per customer. As shown in Figure A-8, Enbridge is in the highest quartile compared to the 28 U.S. natural gas utilities in 2011.

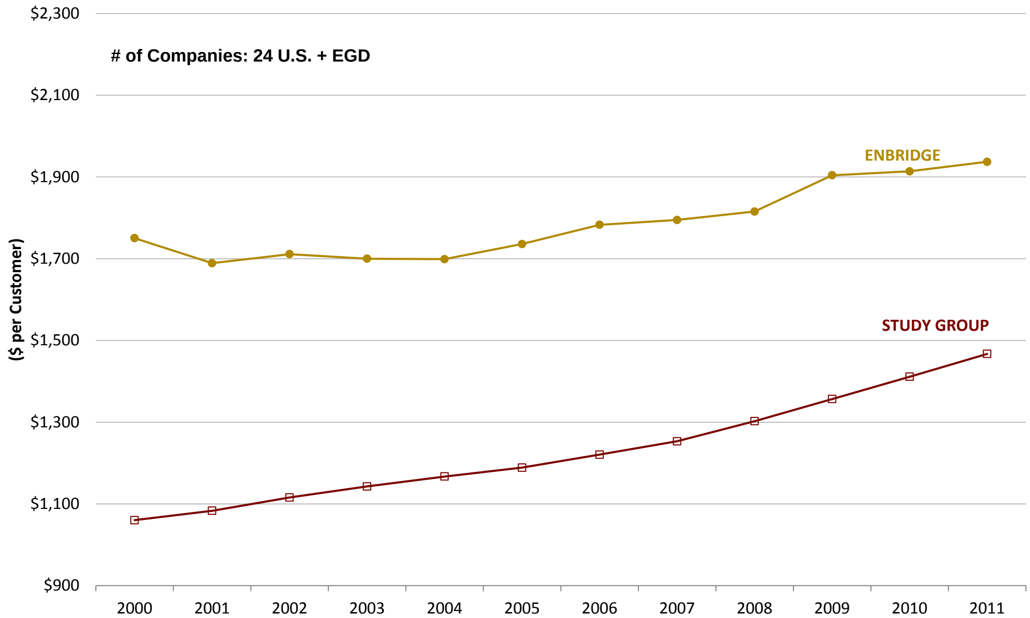
Figure A-8: Total 2011 Net Plant per Customer

(Includes Transmission, Storage, Distribution and Allocated General Plant)



As illustrated in Figure A-9, both Enbridge and the U.S. peer group have experienced growth in net plant per customer over the 2000 to 2011 time period, but Enbridge's net plant per customer grew at a considerably slower rate than the U.S. peer group.

Figure A-9: Total Net Plant per Customer[81]
(Includes Transmission, Storage, Distribution, and Allocated General Plant)



2. *Net Plant per Unit of Volume*

As illustrated in Figure A-10, with respect to total net plant per unit of volume, Enbridge falls below the median of the peer group in 2011. As shown in Figure A-11, over the entire time period, both the industry and Enbridge's net plant per unit of volume generally increased, although Enbridge's rate of growth has slowed by comparison to the study group in recent years.

81 The line charts, which compare costs over the entire 2000 to 2011 period, are expressed in own-country US and Canadian dollars for both the study group and Enbridge, which avoids issues associated with year-to-year exchange rate differences.

Figure A-10: Total 2011 Net Plant per Volume
(Includes Transmission, Storage, Distribution and Allocated General Plant)

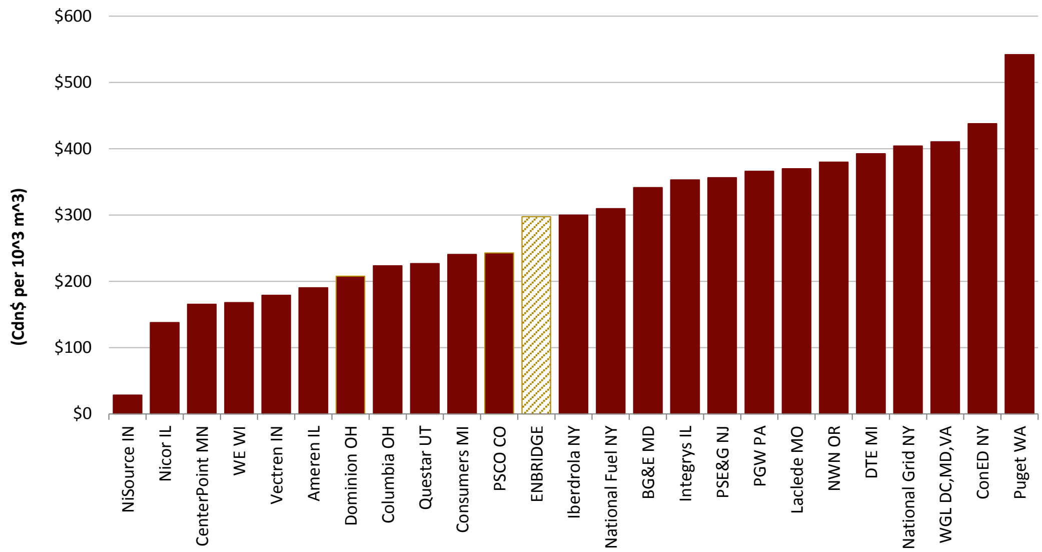
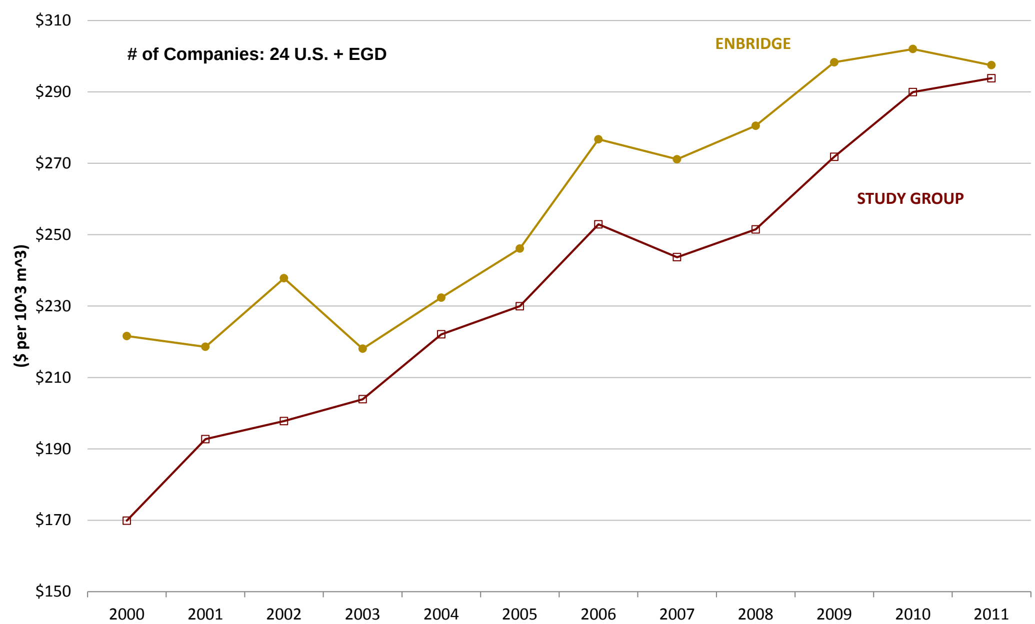


Figure A-11: Total Net Plant per Volume
(Includes Transmission, Storage, Distribution, and Allocated General Plant)

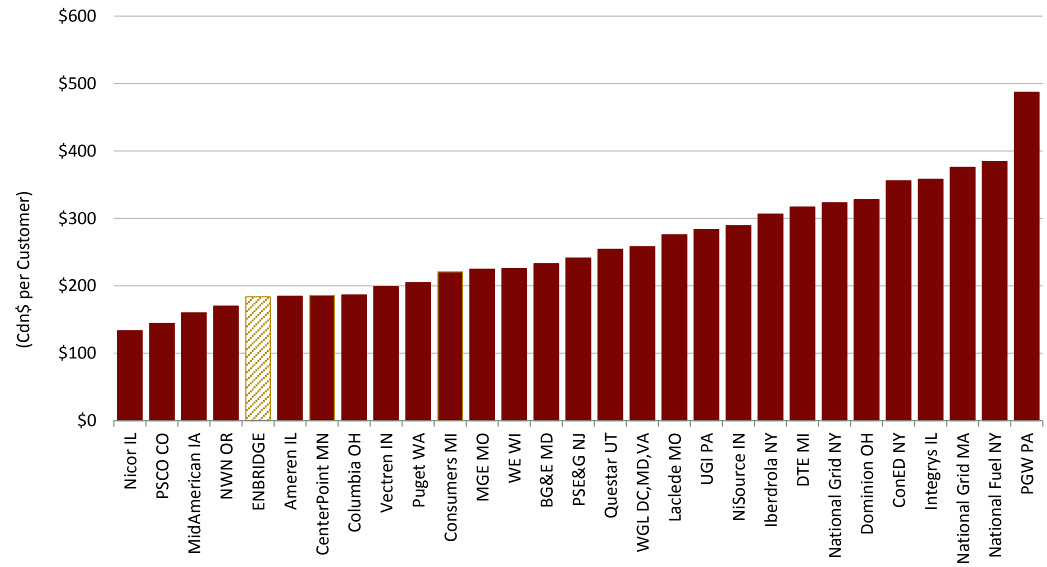


3. Gas O&M Expenses per Customer

As shown in Figure A-12, Enbridge was in the lowest quartile in terms of gas O&M expense per customer.

Figure A-12: Total 2011 Gas O&M Expenses per Customer

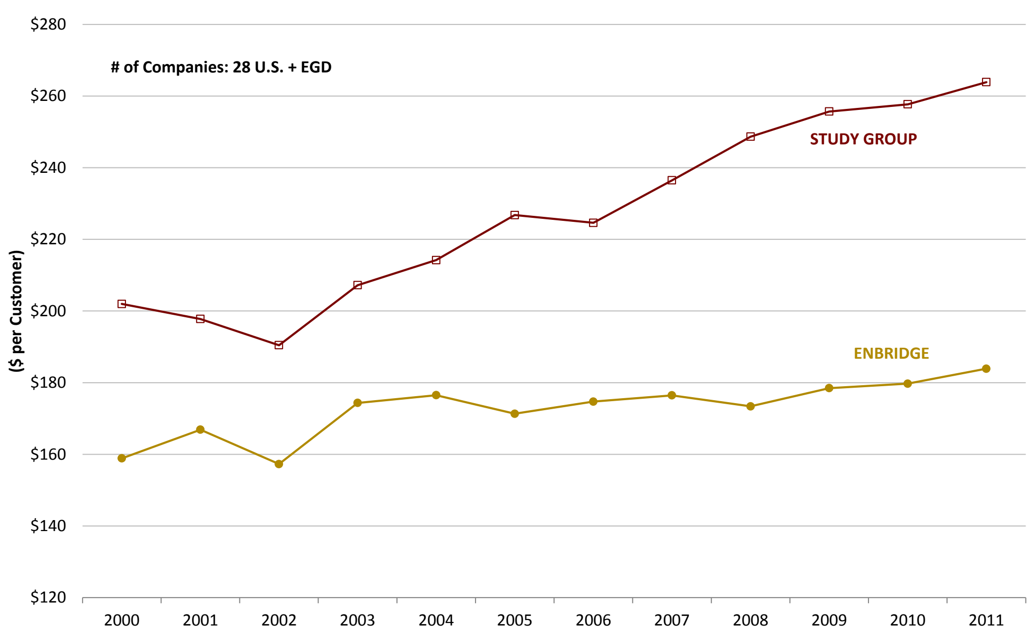
(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



Over the 2003 to 2011 time period, Enbridge's O&M expense per customer metric increased modestly with an average of approximately $177 per customer, whereas the U.S. peer group average has grown steadily since 2002.

Figure A-13: Total Gas O&M Expenses per Customer

(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)

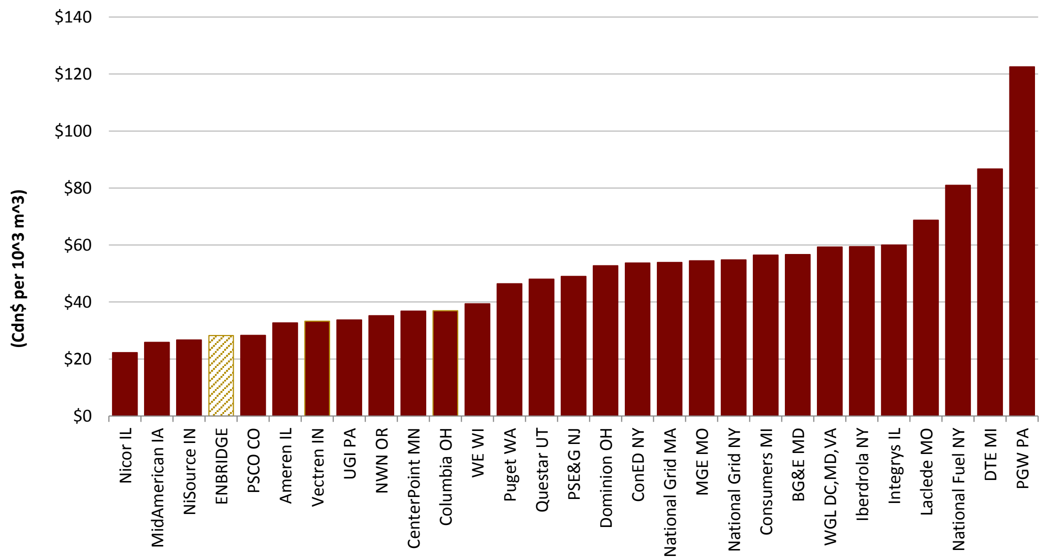


4. Gas O&M Expenses per Unit of Volume

Figure A-14 depicts the total 2011 gas O&M expenses per volume metric for each utility. As shown, Enbridge had the fourth lowest gas O&M expense per volume metric overall. The total gas O&M expense includes transmission, storage, distribution, customer-related, sales and A&G expenses.

Figure A-14: Total 2011 Gas O&M Expenses per Volume

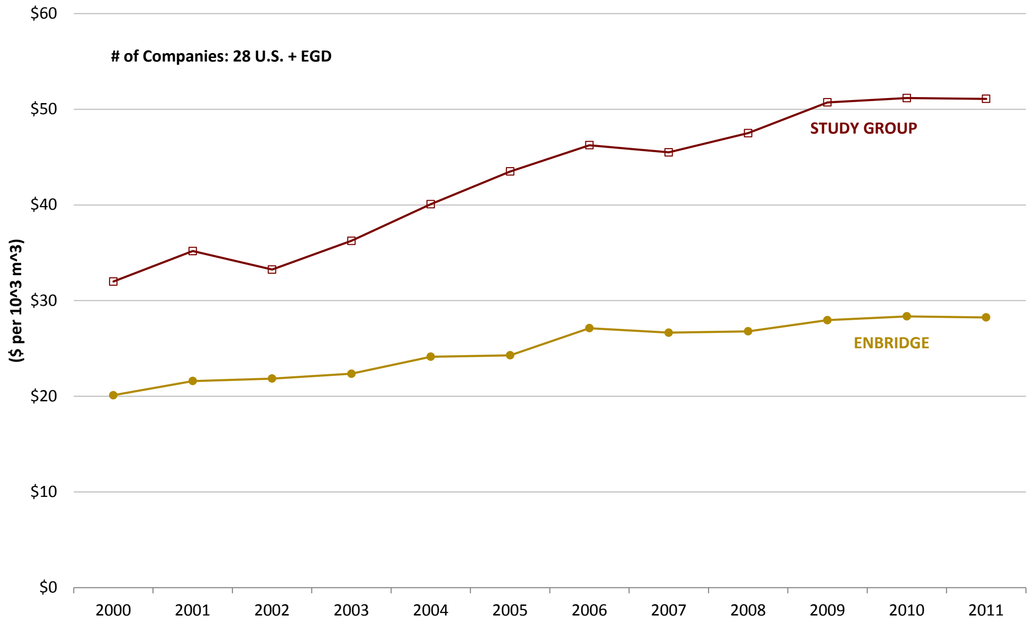
(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



As illustrated by Figure A-15, both Enbridge and the U.S. peer group have experienced an upward trend in the gas O&M expense per volume metric over the 2000 to 2011 time period, although the increase has been greater for the U.S. peer group. The general decline in volume/customer is partly responsible for this overall trend.

Figure A-15: Total Gas O&M Expenses per Volume

(Includes Transmission, Storage, Distribution, Customer-related, Sales and A&G Expenses)



5. *Labour Costs per Customer*[82]

Figures A-16 and A-17 show the total labour costs per customer for 2011, both excluding and including capitalized amounts, for Enbridge and each of the natural gas utilities in the peer group. In terms of labour costs, Enbridge was in the lowest quartile for labour costs per customer compared to the peer group overall.

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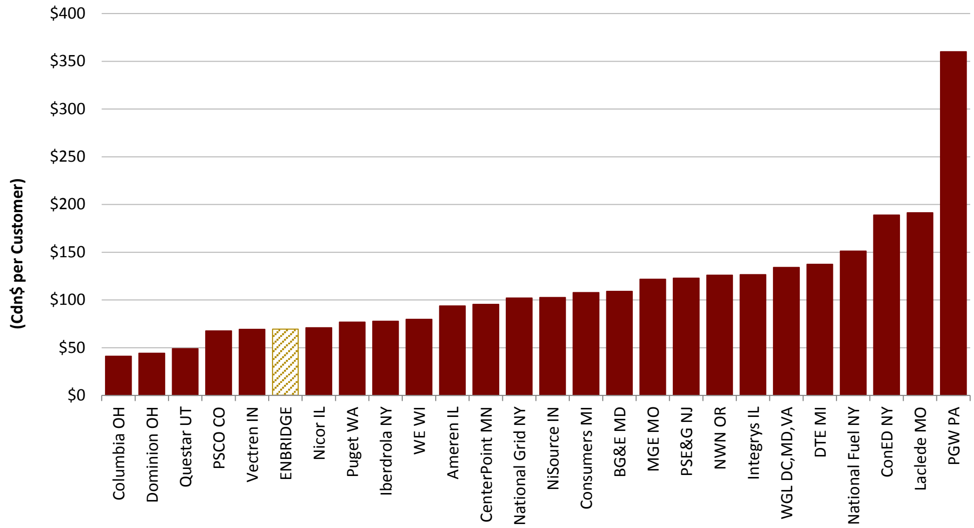
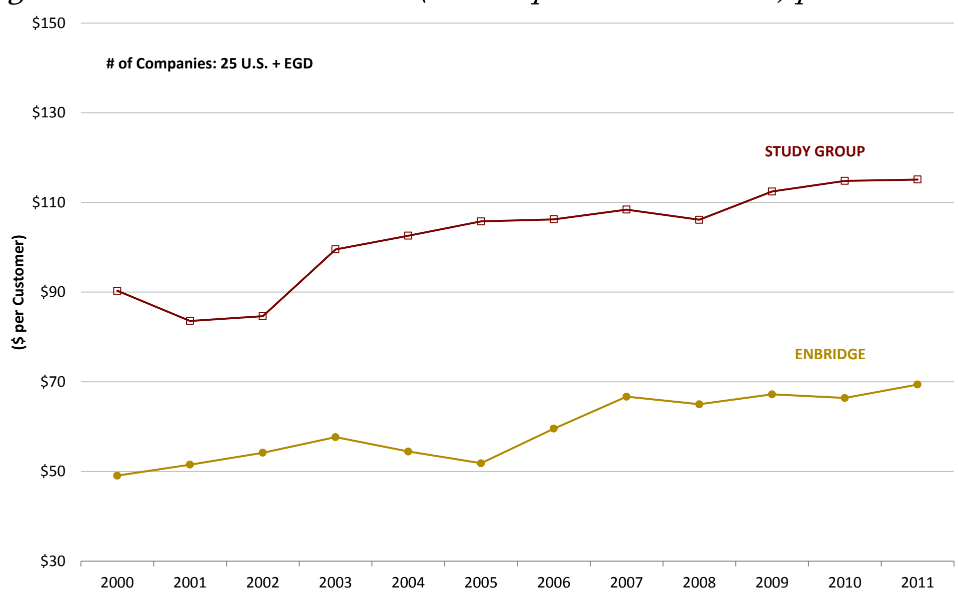
82 During the update to include 2011 data, a few historical data points were revised based on additional information becoming available. These revisions did not change the results in any meaningful way.

Figure A-16: Total 2011 Labour Costs (excl. Capitalized Amounts) per Customer



While both Enbridge and the U.S. peer group's labour costs (excluding capitalized amounts) per customer have trended upward, Enbridge's labour costs (excluding capitalized amounts) per customer flattened out over the 2007 to 2011 time period.

Figure A-17: Total Labour Costs (excl. Capitalized Amounts) per Customer



As shown in Figures A-18 and A-19, when including capitalized costs in the labour costs per customer metric, Enbridge ranks in the second lowest quartile in 2011. Both Enbridge and the U.S. peer group have experienced an increase in labour costs per customer over the 2000 to 2011 time period (including capitalized amounts).

Figure A-18: Total 2011 Labour Costs (incl. Capitalized Amounts) per Customer

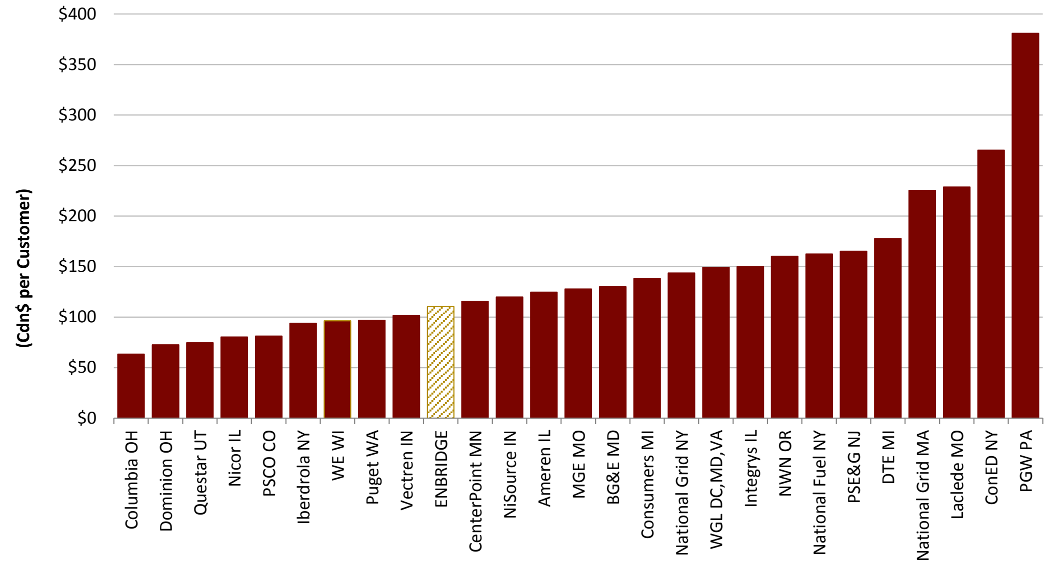
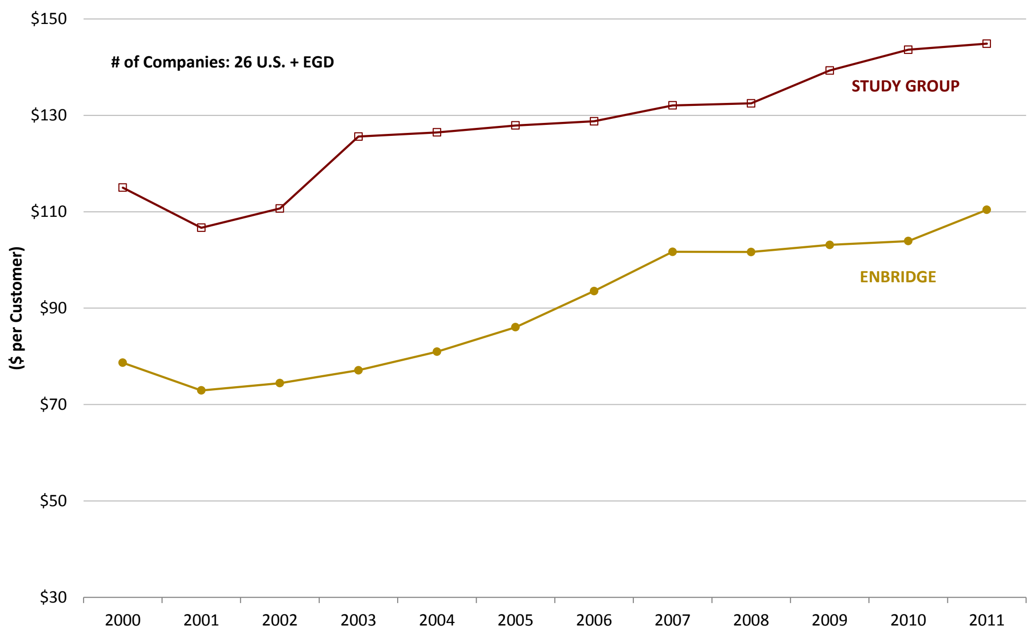


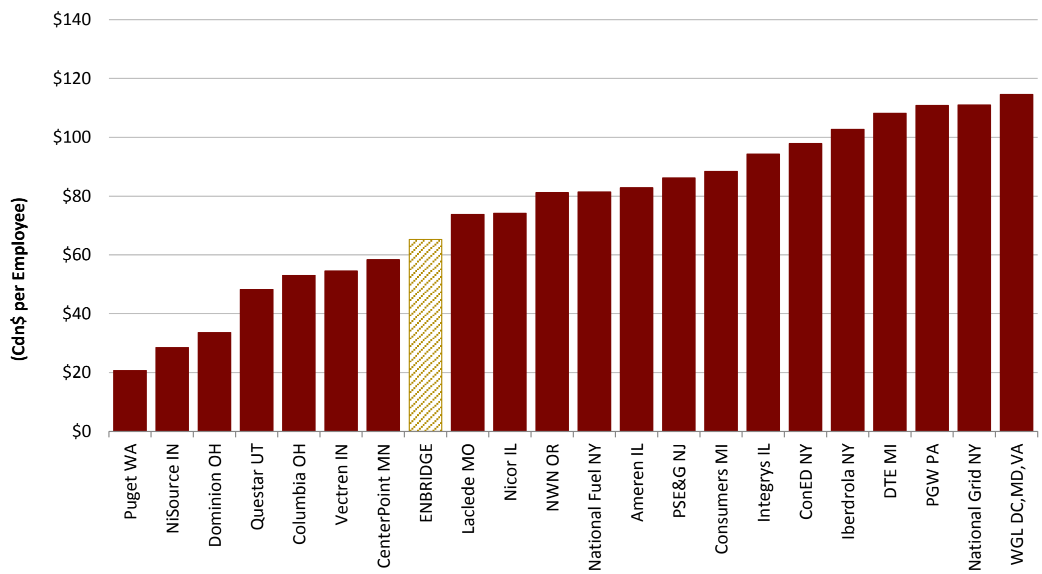
Figure A-19: Total Labour (incl. Capitalized Amounts) per Customer



6. *Labour Costs per Employee*[83]

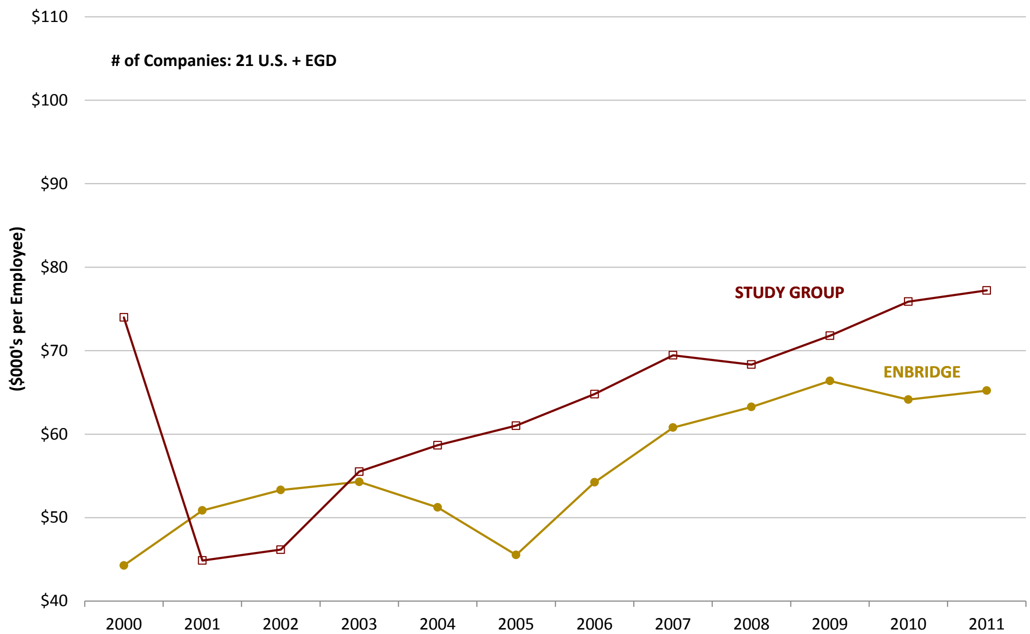
In terms of labour costs per employee, Enbridge's labour cost of approximately $65,000 per employee is lower than the average across the peer group, and ranks eighth overall as illustrated in Figure A-20. Figure A-21 demonstrates that labour costs per employee for both EGD and the U.S. peer group trended upward between 2005 and 2009. In 2010 and 2011, the U.S. peer group continued the upward trend; however, Enbridge experienced a decrease in labour costs per employee.

Figure A-20: Total 2011 Labour Costs (excl. Capitalized Amounts) per Employee



83 During the update to include 2011 data, a few historical data points were revised based on additional information becoming available. These revisions did not change the results in any meaningful way.

Figure A-21: Total Labour Costs (excl. Capitalized Amounts) per Employee



When including capitalized costs in the labour costs per employee metric, Enbridge ranks near the median of the peer group in 2011, as illustrated in Figure A-22. Figure A-23 demonstrates that over the 2001 to 2011 time period, both Enbridge and the U.S. peer group of 22 utilities have experienced steady increases in labour costs per employee (including capitalized labour).

Figure A-22: Total 2011 Labour Costs (incl. Capitalized Amounts) per Employee

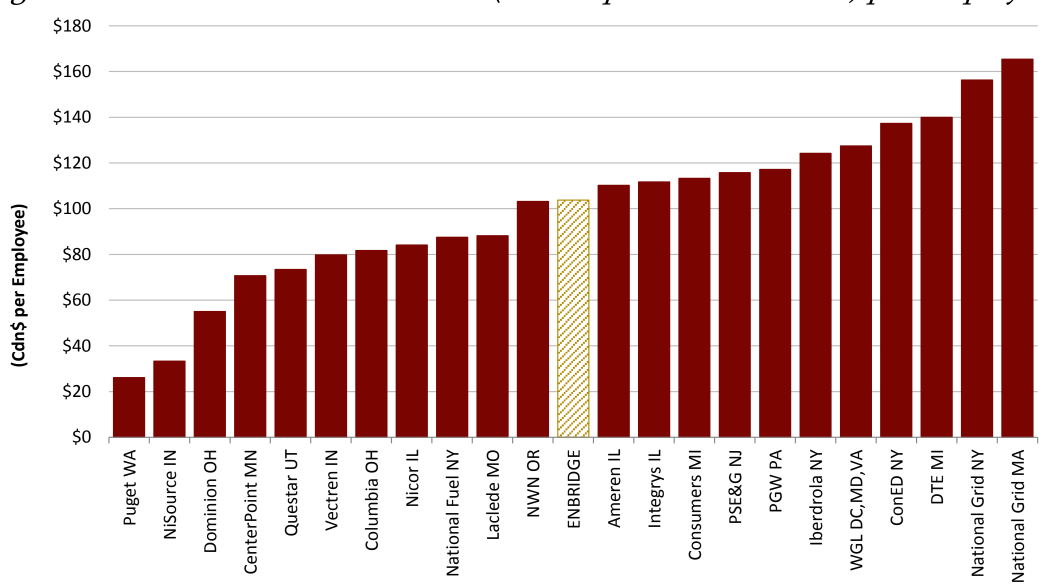
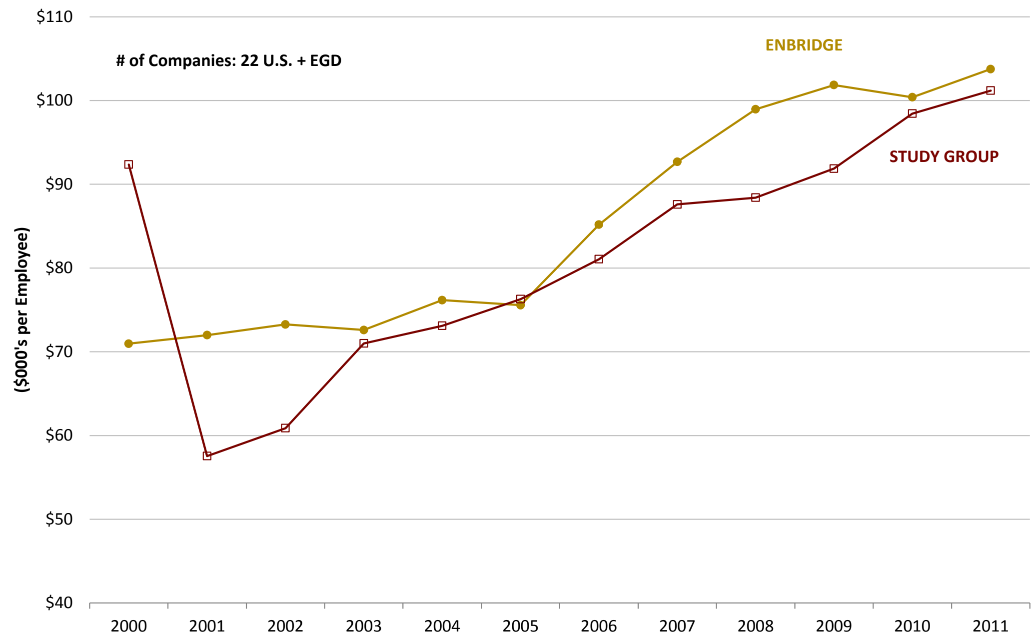


Figure A-23: Total Labour Costs (incl. Capitalized Amounts) per Employee



7. Customers per Employee

Figures A-24 and A-25 depict the total natural gas customers per employee; Enbridge has the sixth highest level of customers per employee in 2011. Over the 2000 to 2011 time period, Enbridge has maintained a high level of natural gas customers per employee as compared to the U.S. peer group average.

Figure A-24: Total 2011 Natural Gas Customers per Employee

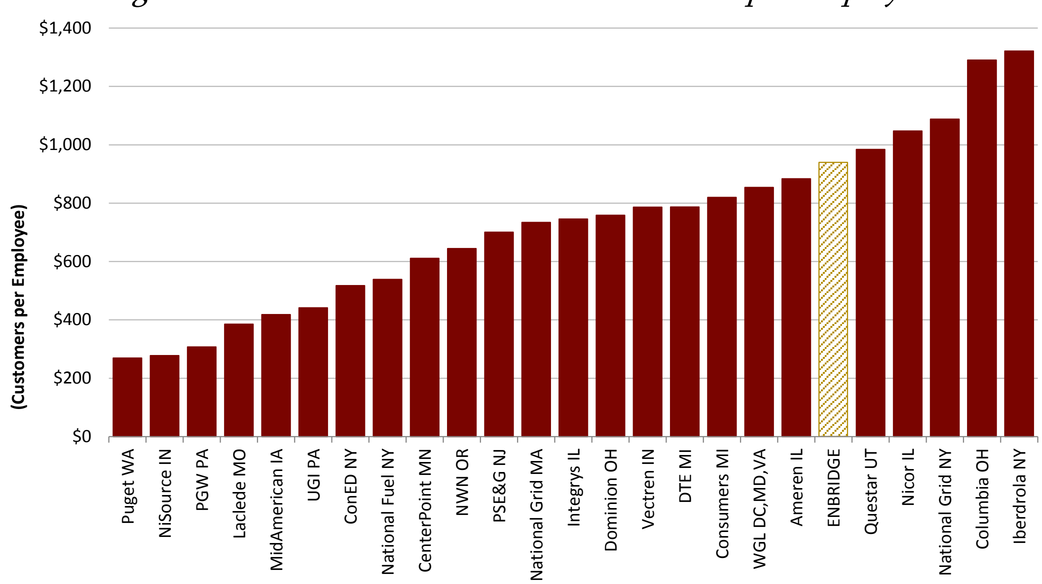
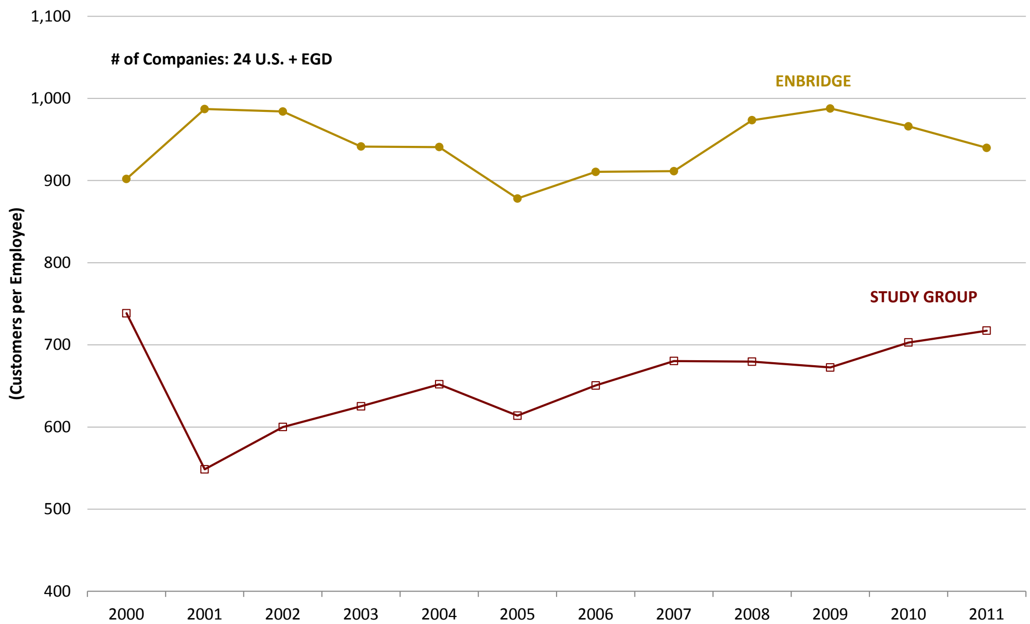


Figure A-25: Total Natural Gas Customers per Employee



III. CONCLUSIONS

The benchmarking analysis contrasts Enbridge with a group of 28 U.S. natural gas utilities. The benchmarking analysis in aggregate indicates that Enbridge is among the most efficient of its U.S. peers.

In terms of comparative size and composition of the Company's service area:

- Enbridge has the 3rd highest customer count and 3rd highest throughput as compared to the U.S. utilities in the peer group, suggesting the potential for scale economies.
- The Company's customer count is, however, also 92% residential.
- Reflecting this customer profile, the Company ranks 5th highest in terms of average gas volume per customer in 2011.
- Reflecting the relatively urban nature of EGD's service area, the Company ranks 7th highest in terms of customers per mile of distribution main and 5th highest in term of volumes per mile of distribution main.

In terms of comparative metrics for capital, operating and maintenance costs:

- The Company ranks 5th highest in terms of overall net plant invested per customer in 2011. Net plant invested per customer has risen over the past decade for both EGD and the US peer group.
- Expressed on a volumetric basis, Enbridge ranks in the middle of all companies on a net plant per unit of system throughput. Due to declining use per customer, net invested plant per unit of throughput has risen more sharply for both EGD and the US peer group over the past decade, however Enbridge slightly decreased in 2011.
- O&M costs per customer for Enbridge are the 5th lowest overall in 2011. These costs have risen more slowly for EGD than for the peer group over the decade, and have remained relatively level for EGD during the 2007 to 2011 IR period measured.
- Expressed on a volumetric basis, Enbridge's O&M costs rank 4th lowest overall. EGD's O&M costs per unit of throughput have risen more slowly than the US peer group's over the past decade.
- Labour costs for Enbridge place the Company at 6th lowest overall in 2011 on a per customer basis excluding capitalized costs and 10th lowest in 2011 including capitalized costs. Enbridge's non-capitalized labour costs have risen more slowly than the US peer group in recent years.
- Expressed on a per employee basis, Enbridge's labour costs ranked 8th lowest overall excluding capitalized costs in 2011, and near the median including capitalized costs.

- When considering customers served by utility workforce, Enbridge ranked 6th highest in 2011. EGD has steadily outperformed its US peer group over the decade, although the gap has narrowed in recent years.

One would expect a utility of Enbridge's size and scale to be among the most efficient of its peers, even though its urban service area, residential customer concentration, and declining use per customer present cost challenges. One could argue that National Grid NY is most like Enbridge, with over 2 million customers and a relatively high customer concentration per kilometer of main, yet Enbridge ranks 5th lowest overall in O&M expenses per customer in 2011 while National Grid NY ranks 23rd, and in 2010, Enbridge ranked 6th lowest, while National Grid NY ranked 22nd. More consistent with expectations, the second largest company in terms of customers, Northern Illinois Gas, is also the most efficient in terms of O&M costs per customer, just ahead of Enbridge which ranks 3rd highest in customers and 5th lowest in O&M costs per customer.

On balance, the benchmarking analysis indicates that Enbridge is among the most efficient of its U.S. peers in most categories measured. The exceptions are net plant per customer, net plant per unit of volume, and labour costs (including capitalized labour) per employee, where the Company is closer to or above the average. Examining trends over the 2000 – 2011 period measured, Enbridge has generally sustained or improved its position in relation to its peers, including during the most recent IR plan period.

APPENDIX B: PRODUCTIVITY ANALYSIS DATA SOURCES AND METHODOLOGY

I. PRODUCTIVITY ANALYSIS DATA SOURCES

Concentric's analysis of EGD's productivity is primarily based on data provided by EGD for the years 2000 through 2011. Data provided by the Company includes historical expenses, plant, customer count, throughput, rate of return, and weather data. The industry productivity analysis is based on data compiled from publicly available sources and commercially available databases for the U.S. natural gas utilities included in the industry study group. Although the industry productivity analysis is primarily based on data from 2000 to 2011, some data were collected for other periods of time.[84] For the industry productivity analysis, necessary data is available for 1999 to 2011; for EGD, the necessary data is available for 2000 to 2011. Concentric used data from 2000 to 2011, consistent with the goal of using the most recent 10-15 years of data to calculate productivity.

Company-specific data for U.S. natural gas utilities was largely compiled from annual reports filed by the individual local distribution companies ("LDCs") with their state regulatory commissions ("Annual LDC Reports"),[85] and the Annual Reports of Natural and Supplemental Gas Supply and Disposition ("Form EIA-176")[86] filed with the U.S. Energy Information Administration ("EIA"). These sources were used to compile a U.S. natural gas utility database, which was used to conduct the productivity analysis for the industry study group.

The database was checked for completeness, accuracy, and consistency. Data was gathered at the individual operating subsidiary level; data for a number of different individual operating subsidiaries were combined to account for mergers and acquisitions in order to develop complete, consistent data series (e.g., companies that now comprise National Grid (NY) include (1) KeySpan Energy Delivery (a.k.a. KED-NY, formerly Brooklyn Union), (2) KeySpan Gas East (a.k.a. KED-LI, formerly Long Island Lighting Company), and (3) Niagara Mohawk Power Corporation). In addition, data for separate operating subsidiaries of the

84 For example, plant in service and additions to plant data starting in 1995 was used to develop the capital quantity input index.

85 Concentric primarily relied on data from the Annual LDC Reports as provided through the SNLxL database.

86 Company-specific data from Form EIA-176 was compiled primarily from the SNLxL database of the SNL Financial website and supplemented by data from the EIA-176 query system.

same parent company within a single state were aggregated at the state level.[87] Finally, gaps in data (i.e., missing data) and data inconsistencies were identified by examining line graphs for each data series for each company. The following sections provide a detailed discussion of the data utilized in the Input Index and the Output Index calculations for the industry study group.

A. Input Index Data

The following U.S. natural gas utility cost data was used to develop the Input Index for the industry study group:[88]

- Labour
  - Gas Salaries and Wages – O&M (i.e., excluding capitalized amounts) for 1999-2011
  - Administrative and General ("A&G") – Employee Pensions and Benefits for 1999-2011
- Materials
  - O&M Expenses (including Distribution, Transmission, Storage, Customer Accounts, Customer Service, Sales, and A&G) for 1999-2011
- Capital
  - Gas Plant In Service (including Distribution, Transmission, Storage, LNG Processing, and General) for 1995
  - Accumulated Depreciation (including Distribution, Transmission, Storage, LNG Processing, and General) for 1995
  - Gas Plant Additions, by Major Category (including Distribution, Transmission, Storage, LNG Processing, and General) for 1996-2011

For the Input Index, Concentric primarily relied on data compiled at the operating subsidiary level from the annual reports filed by the individual LDCs with their respective state regulatory commissions ("Annual LDC Reports") as provided through the SNLxL database

87 For example, data for the gas operations of Con Edison of New York and Orange & Rockland Utilities, which are operating subsidiaries in the state of New York of Consolidated Edison, Inc., were combined.

88 In all cases gas costs were excluded as they are largely outside of the utility's control and tend to be a pass through item. Ideally other costs that are largely outside of the utility's control (e.g., energy efficiency/DSM and pensions) would have also been excluded; however, these costs were not consistently reported as separate line items; therefore identification and exclusion of these costs was not possible.

from the SNL Financial website. When data was missing and not available directly through the SNLxL database, Concentric manually entered the data from the Annual LDC Reports, if possible (e.g., gas salaries and wages – O&M data was not available through the SNLxL database for most operating subsidiaries, so this data was manually entered from the Annual LDC Reports).

The missing/inconsistent data points were supplemented by:

- Data from the Uniform Statistical Reports as provided and reported through AGA's electronic Gas Utility Statistics ("eGUS") database, if it was consistent with the data and data trends in the Annual LDC Reports; or
- Calculations based on straight-line trends in the data.

Overall, approximately 1% of the state-level company data used in the Input Index were supplemented by data from the AGA's eGUS database and approximately 2% were based on calculations of straight-line trends. Figure B-1 provides details of the data manipulations by data series utilized in the Input Index for the industry study group.

Figure B-1: Adjustments to Reported Data for Input Index Database for the 25 Company Industry Study Group

	Data Sources	Occurrence of Adjustments	
Data Description	LDC Annual Reports	% from AGA eGUS Database	% Estimated
Labour			
Gas O&M Salaries & Wages	1999-2011	7.1%	2.1%
A&G-Employee Pensions & Benefits	1999-2011	2.6%	1.0%
Materials			
O&M Expenses, by Major Category	1999-2011	0.4%	0.3%
Capital			
Gas Plant In Service, by Major Category	1995-2011	0.1%	1.3%
Gas Plant In Service, by Major Category	1995	0.0%	2.4%
Accumulated Depreciation, by Major Category	1995-2011	6.6%	4.0%
Accumulated Depreciation, by Major Category	1995	10.3%	7.7%
Gas Plant Additions, by Major Category	1996-2011	0.0%	2.7%
TOTAL		**1.0%**	**1.7%**

B. Output Index Data

The following U.S. natural gas utility sales data were used to develop the Output Index for the industry study group:[89]

- Customers
  - Sales Customers by Segment for 1999-2011
  - Transportation Customers by Segment for 1999-2011
- Volume[90]
  - Sales Volume by Segment for 1999-2011
  - Transportation Volume by Segment for 1999-2011
- Revenues
  - Operating Revenues by Segment for 1999-2011
  - Production Expenses for 1999-2011

For the Output Index, Concentric primarily relied on data compiled at the operating subsidiary level from the Annual Reports of Natural and Supplemental Gas Supply and Disposition ("Form EIA-176") filed with the U.S. Energy Information Administration ("EIA") as provided through the SNLxL database from the SNL Financial website for customers and volumes. When customer and volume data were not available directly through the SNLxL database, Concentric was able to manually supplement with data from EIA's own Form-176 database. Missing/inconsistent customer and volume data points were supplemented by data from the Annual LDC Reports if they were consistent with data in surrounding years, as reported by EIA Form-176 filings. Overall, approximately 6.6% of the customer and volume data used in the Output Index for the industry study group was supplemented by data from Annual LDC Reports, and approximately 0.3% was estimated using available data.

Revenues and production expenses were compiled from Annual LDC Reports. Missing/inconsistent revenue and production expense data were estimated. Approximately

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89 Data were generally available for the period 1995 to 2011; the Output index is determined with data from 1999 to 2011.

90 Volume data by segment was used in estimating distribution revenues, which were used to develop output index weights.

0.2% of the Revenue and Expense data was estimated using available data. Figure B-2 provides details of the adjustments and modifications to the data used in the Output Index.

Figure B-2: Adjustments to Reported Data for Output Index Database
For the 25 Company Industry Study Group

Data Description	Data Source EIA-176 Database	Occurrence of Adjustments: % from LDC Annual Reports	Occurrence of Adjustments: % Estimated
Output Index Data			
Sales Customers, by Segment	1999-2011	5.2%	0.5%
Transportation Customers, by Segment	1999-2011	6.8%	0.6%
Sales Volume, by Segment	1999-2011	7.9%	0.0%
Transportation Volume by Segment	1999-2011	7.0%	0.0%
Total Natural Gas Volume	1999-2011	3.5%	0.0%
TOTAL		**6.6%**	**0.3%**

Data Description	Data Source LDC Annual Reports	Occurrence of Adjustments % Estimated
Output Index Data		
Natural Gas Operating Revenue	1999-2011	0.2%
Production Expense	1999-2011	0.2%
TOTAL		**0.2%**

C. Other Data

In addition, authorized industry return on equity ("ROE") and debt-equity ratios were obtained from SNL Financial Regulatory Research Associates ("RRA") for all U.S. gas utilities.

Data on heating degree days ("HDDs") were obtained from the National Climatic Data Center for the U.S. states.

Lastly, data was obtained from other publicly-available or subscription sources, including:

- Bloomberg,
- Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor,
- Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce,
- Statistics Canada ("StatsCan"), and
- Whitman, Requardt & Associates.

II. INPUT INDEX METHODOLOGY

A. Introduction

The company-specific input quantity index measures trends in the quantity of inputs used by each company. The TFP input indexes are an aggregation of labour, materials and capital quantity sub-indexes. Input quantity annual growth rates for each company are determined by weighting the growth rates of each of the input quantity sub-indexes (labour, materials, capital) by the sub-index cost as a percent of total cost, by company and year. The Labour and Materials indexes are derived from distribution-related expense data that is recorded in the following categories of expense accounts: (a) Operations and Maintenance ("O&M")[91] (b) Administrative and General,[92] (c) Customer Accounts, (d) Customer Service and Informational, and (e) Sales. The Capital quantity indexes are derived from distribution-related Utility Plant accounts.[93]

B. Labour

1. Labour Cost

Concentric used salaries and wages expenses, net of capitalized amounts as the annual labour cost for each company. Labour costs associated with capital projects were not included because these costs are captured in the capital index. The labour costs captured in the labour index, therefore, relate to operations and maintenance ("O&M") activities.[94]

2. Labour Price

For the EGD Labour Sub-Index, the Average Hourly Wages for All Employees in Ontario as published by StatsCan[95] was used (a) to determine the labour price index, and (b) to derive Labour Quantity. For each of the companies in the Industry Study Group, the Employment

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91 Including distribution, transmission, and storage O&M accounts

92 Pensions and benefits expenses were excluded from the analysis.

93 Including utility regulated distribution, transmission, storage, LNG processing, and general plant.

94 Throughout this Appendix Concentric uses the term "O&M" to include distribution-related expenses in the categories of (a) Operations and Maintenance (b) Administrative and General, (c) Customer Accounts, (d) Customer Service and Informational, and (e) Sales.

95 Source: Statistics Canada. Table 282-0069 - Labour force survey estimates (LFS), Ontario, All Employees, wages of employees by type of work, National Occupational Classification for Statistics (NOC-S), sex and age group, unadjusted for seasonality; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on November 6, 2012.

Cost Index for Wages and Salaries for Utilities published by BLS[96] was used (a) to determine the labour price index, and (b) in the calculation of Labour Quantity.

3. *Labour Quantity*

The Labour sub-index measures the trend in Labour Quantity. Concentric calculated EGD's annual Labour Quantity by dividing annual labour cost by the StatsCan Total Compensation Index. The Labour Quantity for each of the industry study group companies was calculated by dividing annual labour cost for that company by the BLS Employment Cost Index for that year.

C. Materials

1. *Materials Cost*

The materials sub-index measures the trend in all other inputs that are not labour or capital-related. In this report, this category is referred to as "materials". The materials sub-index includes all distribution-related non-labour O&M expenses such as equipment rents, leases, cost of materials, and cost of contractors. Annual materials costs for each company were determined by subtracting salaries and wages expenses identified above, and pensions and benefits expenses from the total O&M expenses (including administrative and general expenses, excluding production-related O&M expenses).

2. *Materials Price*

For the EGD Materials Sub-Index the Canadian Gross Domestic Product Implicit Price Index, Final Domestic Demand ("GDP-IPI-FDD"),[97] was used for the materials price index. The U.S. Gross Domestic Product Implicit Price Deflator ("GDP-IPD")[98] was used for the materials price index for the industry study group analysis.

3. *Materials Quantity*

The Materials sub-index measures the trend in Materials Quantity. Concentric calculated the Materials Quantity for each company by dividing annual nominal materials cost for that

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96 Source: BLS, Employment Cost Index Historical Listing, Continuous Occupational and Industry Series, September 1975-September 2012 (December 2005=100), Table 9, October 31, 2012.

97 Source: Statistics Canada, Table 380-0003, Gross domestic product (GDP) indexes, Canada, Implicit price indexes, Final domestic demand, quarterly (2002=100) available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on October 9, 2012.

98 Source: BEA, Table 1.1.9. Annual Implicit Price Deflators for Gross Domestic Product (Index Numbers, 2005=100), last revised September 27, 2012.

company by the annual materials price index. Materials Quantity is equivalent to real non-labour O&M expense (expressed in $2009).

D. Capital

1. Capital Approach

Measuring Capital quantity is less straightforward than measuring Labour or Materials quantity. In recent utility TFP analyses, three approaches to quantifying capital have been used, referred to as "Geometric Decay", "Cost of Service" and "One Hoss Shay".

<u>Geometric Decay:</u> In the geometric decay model, capital quantity reflects the concept that the plant additions of each vintage become less productive, or efficient, over time, and that the pattern of the decline in productivity is geometric. The geometric decay capital price, which is also called the user cost or service price, represents the price of employing a unit of net capital for one year. The capital price is based on the relationship between the price of new capital and the present value of future services of current capital; the Geometric Decay capital price incorporates financial costs and economic depreciation.[99] The economic depreciation[100] component in the price calculation measures the decline in the price of the capital asset as it ages. Capital cost is calculated by multiplying the Geometric Decay capital quantity and capital price. The geometric decay approach has been promoted extensively in academic literature.[101]

<u>Cost of Service:</u> The cost of service approach to calculating capital cost reflects the way capital cost is determined in utility regulation.[102,103] Cost of Service capital quantity is

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99 Economic depreciation measures the change in the market value of an asset over time while the accounting depreciation reveals nothing about the market value. Accounting depreciation is simply the allocation of the historical cost of an asset to the periods in which the services of the asset are recovered from ratepayers.

100 In the case of geometric decay, economic depreciation is equal to efficiency decline.

101 A few example include: Hulten, Charles (1990), "The Measurement of Capital", in Ernst Berndt and Jack Triplett (eds.) Fifty Years of Economic Measurement, National Bureau of Economic Research Studies in Income and Wealth, volume 54, The University of Chicago Press, Chicago.; Hulten, Charles and Frank Wykoff (1981), "The Estimation of Economic Depreciation" in Charles Hulten (ed.) Depreciation, Inflation, and the Taxation of Income from Capital, Urban Institute, Washington.; Mark E Doms, 1992. "Estimating Capital Efficiency Schedules Within Production Functions," Working Papers 92-4, Center for Economic Studies, U.S. Census Bureau; and Nehru, Vikram and Ashok Dhareshwar (1993). A New Database on Physical Capital Stock: Sources, Methodology and Results, Revista de Analisis Economico. 8: 37–59.

102 A few examples include: Lowry, Mark (2007), "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," Report filed on behalf of the Ontario Energy Board.; Lowry, Mark (2011), "PBR Plans for Alberta Energy Distributors," Report filed on behalf of the Consumer's Coalition of Alberta before the Alberta

determined based on the assumption that the efficiency of each vintage of plant additions declines in accordance with a straight line pattern.[104] The Cost of Service capital price is determined by a weighted average of current and past construction or asset prices. As a result, the Cost of Service capital price is an implicit price determined by the deflated sum of financial costs and accounting depreciation. The financial costs and accounting depreciation are both based on the historic (book) value of the plant.

One Hoss Shay: The One Hoss Shay approach to determining capital cost assumes that an asset retains full efficiency until the end of its service life.[105] The One Hoss Shay Capital quantity is measured by gross plant; total gross plant is determined by summing plant additions by vintage. The One Hoss Shay Capital price is computed by incorporating financial costs and economic depreciation; economic depreciation must be estimated using several factors, including the real rate of interest (discount factor).[106]

The simplicity of the geometric model provides several advantages over the cost of service and One Hoss Shay models, including: economic depreciation equals efficiency decline, no system of vintage accounting needs to be maintained because of the constant rate of depreciation, and depreciation is independent of the real rate of interest.[107] The geometric decay model is the only model where the economic depreciation equals the efficiency decay. This simplifies the calculation because it avoids the tedious task of estimating the economic depreciation. In addition, if the two are not equal, the depreciation function can take on several forms due to its sensitivity to factors such as the real interest rate. For example, in the case of One Hoss Shay, if the interest rate is zero, we can conclude that the depreciation will exhibit a straight line pattern; however, if the real interest rate is positive, the depreciation function will exhibit a concave pattern. The geometric decay model eliminates

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utilities Commission.; and Kaufmann, Larry (2011), "Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans," Report filed on behalf of the Ontario Energy Board.

103 The lack of detailed documentation and academic literature on the Cost of Service approach does not permit us to fully understand the methodology.

104 That is, the efficiency of a specific addition to plant declines at the same rate (percent of original plant) each year.

105 This approach was recently promoted by NERA in the Alberta generic IR case. Makholm, Jeff (2010), "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," Report filed on behalf of the Alberta Utilities Commission.

106 Due to the interdependence of the Capital price and economic depreciation, One Hoss Shay economic deprecation will in general follow a concave pattern, which assumes that the price of the asset declines at a slower pace in earlier years and an accelerated pace toward the end of its service life.

107 Harper (1982), "The Measurement of Productive Capital Stock, Capital Wealth, and Capital Services."

the necessity of a depreciation calculation. Furthermore, the geometric decay model does not require a system of vintage accounting due to the constant rate of depreciation. The capital price does not depend on the historical pattern of past asset prices; it only depends on the current price of used assets, which can be expressed in terms of a new asset's price.[108] This greatly reduces the data demands associated with the geometric decay model.

The geometric decay model has been applied empirically on numerous occasions. One highly cited empirical study was developed by Hulten and Wykoff (1981). Hulten and Wykoff estimated the capital price index (age/price profile) by using prices of used capital assets. The study examined three common models: One Hoss Shay, straight line and geometric decay. Hulten and Wykoff concluded that geometric decay was the most appropriate method for estimating the age/price profile. Due to the dual property discussed above (economic depreciation equals efficiency decay), we can also assume that geometric decay would be the most accurate efficiency profile. Other studies using alternative approaches to estimating efficiency schedules have also been conducted. For example, Doms (1992) estimated efficiency schedules within production functions which resulted in relative efficiencies that declined geometrically.

The cost of service model, while trying to more accurately reflect the way capital cost is determined in utility regulation, has not been extensively studied in scholarly literature; therefore, there is no independent evaluation of the approach. In addition, to our knowledge, the model has only been used empirically by Pacific Economics Group. These factors make the cost of service approach difficult to evaluate. In addition, the model contains theoretical inconsistencies. Hulten (1990) showed that economic depreciation and efficiency decay are not independent concepts. One cannot select an efficiency pattern independent of the depreciation pattern and one cannot select a depreciation pattern independent of an efficiency pattern. Hulten used the example of straight line efficiency decay and showed that if one selects straight line efficiency decay then one has committed to using a non-straight line pattern of depreciation. The cost of service model uses straight line efficiency decay and depreciation, which is in direct violation of the theoretical framework developed by Hulten. In addition, accounting depreciation is being incorrectly used a proxy for economic depreciation.

[108] Fuss (2012), "Response to Pacific Economics Group's September 2011 Report" Report filed on behalf of Union Gas before the Ontario Energy Board.

The One Hoss Shay method assumes that assets retain full efficiency until the asset reaches the end of its service life. However, OECD (2001)[109] states that there are relatively few assets that will actually maintain full efficiency throughout their useful lives. As noted above, Hulten (1990) showed that economic depreciation and efficiency decay are not independent concepts and therefore, cannot be chosen independently of one another. In the case of One Hoss Shay efficiency decline, the depreciation function often takes on a concave pattern.[110] However, a concave depreciation function is often at odds with empirical research. As Hulten and Wykoff (1981) show, depreciation generally exhibits a convex or geometric pattern. Furthermore, if a One Hoss Shay pattern of efficiency for an aggregation of capital assets is used, it is assumed that the useful life of all those assets are the same and that the efficiency decay of each asset is One Hoss Shay. Both assumptions are implausible.

Therefore, Concentric used the geometric decay approach to estimate capital cost and capital price, based on the following considerations:

(a) The geometric decay approach has been studied extensively in the literature and applied empirically in academic studies, including studies of utility regulation.

(b) The geometric approach is (relatively) straightforward.

(c) The Geometric Decay approach is consistent with the theoretical framework for determining capital cost. In capital theory, the price of an asset in a competitive market must be equal to the present discounted value of the expected annual rental rates of that asset over its entire service life with each expected rental rate being weighted by the corresponding annual productive efficiency.[111] The capital quantity and capital price obtained in the geometric decay model satisfies this fundamental equation.

2. Capital Quantity

Capital Quantity is a measure of a utility's distribution capital stock in any year. Capital Quantity reflects the value of the plant that is available to be used in a year, accounting for the value of plant additions in each earlier year and the remaining useful portion of that vintage of plant additions and plant retirements. Ideally Capital Quantity would be measured by compiling the annual additions and retirements, measured in real dollars, starting at a company's inception. However, because published plant data of this nature is

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109 OECD (2001), "Measuring Capital," OECD Manual.

110 Unless the real interest rate is zero, in which case the depreciation function is of the straight line pattern.

111 The theoretical framework is developed in Fuss (2012), Hall and Jorgenson (1967), Hulten (1990) as well as others.

not available for the companies in the Industry Study Group, Concentric estimated the Capital Quantity for a "baseline" year. For the industry study group analysis, the baseline year was 1995;[112] the baseline Capital Quantity was estimated by dividing (1) 1995 book Net Utility Plant, excluding production plant[113] by (2) a composite plant deflator that Concentric developed to reflect the vintages of plant that were in service in 1995. The composite plant deflator is based on the regional Handy-Whitman Index of Cost Trends of Gas Utility Construction ("Handy-Whitman Index"). The formula for calculating the 1995 capital quantity is shown below:

$$K_{1995} = \frac{Net\ Plant_{1995}}{\sum_{i=1}^{30}\left\{\left[\frac{i}{\sum_{j=1}^{30} j}\right] * HandyWhitmanIndex_{1965+i}\right\}}$$

A similar methodology was used for the EGD capital quantity, except that: 1) the baseline year was 2000, and 2) the composite plant deflator was based on the implicit price index for natural gas distribution investments in Canada obtained from StatsCan.[114]

For each company, the Capital Quantity for each year after the baseline year was calculated by summing, for each year, (a) real plant additions; (b) minus real plant retirements; and (c) Capital Quantity in the prior year. Plant additions were obtained from the Company for the EGD analysis, and from the Annual LDC Filings for each utility in the industry study group analysis. Plant additions were converted to real dollar terms using the appropriate utility plant deflator in that year. Because annual retirement data was not readily available, annual retirements for each company were calculated by applying a common depreciation rate to the Capital Quantity in the prior year for consistency. Enbridge's depreciation rate of 4.14% was used for all companies. The formula for calculating capital quantities after the start year is shown below:

$$K_t = K_{t-1} + \frac{Plant\ Additions_t}{UtilityPlantDeflator_t} - [Depreciation\ Rate *\ K_{t-1}]$$

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112 The earliest year for which plant data was available for the U.S. natural gas utilities was 1995.

113 Concentric calculated Book net plant for 1995 by summing 1995 gross plant for all categories of natural gas plant, excluding production, minus 1995 accumulated depreciation for the same categories of natural gas plant.

114 Source: Statistics Canada, Table 031-0002, Flows and stocks of fixed non-residential capital, by North American Industry Classification System (NAICS) and asset, annual (dollars x 1,000,000); Canada; Current Prices and 2007 Constant Prices; Natural Gas Distribution; Investments; Total Assets; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 6, 2012.

3. Capital Price

As discussed previously, the geometric decay capital price represents the price of employing a unit of capital for one year and is based on the relationship between the price of new capital and the present value of future services of current capital. The price of capital is based on the cost of capital, depreciation, and capital gains.[115] The cost of debt for EGD is the cost of debt reflected in EGD's base rates, and the cost of debt for the industry study group is taken from the Moody's A Utility Bond Index for each applicable year, representing year-to-year fluctuations in utility debt costs. The annual cost of equity for EGD is the Board-approved ROE, and the cost of equity for the industry study group is determined from the average allowed return for all US natural gas utilities in each year, as reported by SNL Financial. In order to determine the annual weighted cost of capital, EGD's equity weighting is set at the Board-authorized average equity share for each year and the equity weighting for the industry study group is the average equity weighting for all US natural gas utilities in each year, obtained from SNL Financial. Annual construction costs for EGD are based on a Canadian implicit price index for natural gas distribution investments,[116] and the Handy-Whitman index for the US industry study group.[117] Capital price for all companies is also adjusted for depreciation, based on Enbridge's depreciation rate of 4.14%. The summation of the cost of capital and depreciation applied to the applicable annual construction cost, and reductions for applicable capital gains determine the capital price for each year. Resulting capital prices are smoothed by calculating a four-year rolling average to reduce volatility, prior to application in the capital cost calculation.

4. Capital Cost

Annual capital cost is calculated as annual capital quantity multiplied by capital price for both EGD and the industry study group.

E. Input Sub-Index Calculation and Results

Industry input quantity index growth rates for each sub-index is determined by calculating cost weighted averages across the companies in the 25 company industry study group and

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115 Based on the calculations in Christensen, L, R, and Jorgenson, D.W. (1969), "The Measurement of U.S. Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, No. 4, December, pp. 293-320.

116 Source: Statistics Canada, Table 031-0002, Flows and stocks of fixed non-residential capital, by North American Industry Classification System (NAICS) and asset, annual (dollars x 1,000,000); Canada; Current Prices and 2007 Constant Prices; Natural Gas Distribution; Investments; Total Assets; available at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 6, 2012.

117 Region-specific Handy-Whitman indices are applied to each company in the US industry sample group.

seven company sub-group. Input sub-index results for the 25 company industry study group, the seven company sub-group and EGD for labour, materials and capital are shown in the following figures.

Figure B-3: Labour Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[118] (2000-2011)

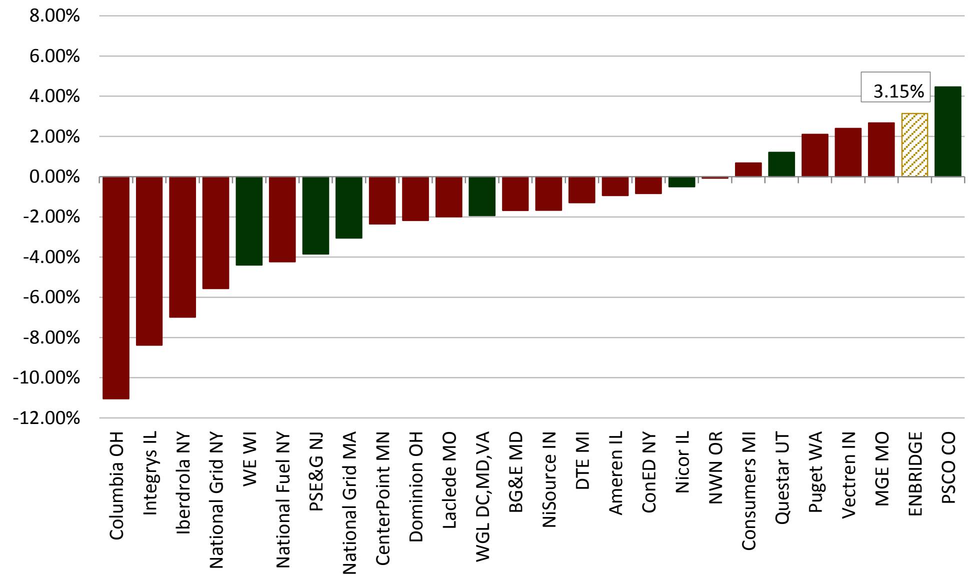
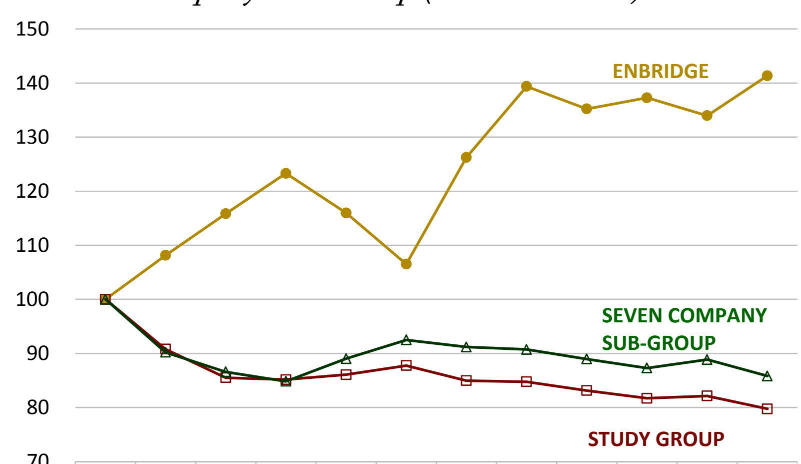


Figure B-4: Labour Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000=100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EGD	100	108	116	123	116	107	126	139	135	137	134	141
Industry Study Group	100	91	86	85	86	88	85	85	83	82	82	80
7 Company Sub-Group	100	90	87	85	89	93	91	91	89	87	89	86

118 The companies in the seven company sub-group are indicated by green shading.

Figure B-5: Labour Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		7 Company Sub-Group		EGD	
		Labour Quantity Growth Rate	Labour Quantity Index	Labour Quantity Growth Rate	Labour Quantity Index	Labour Quantity Growth Rate	Labour Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	-9.65%	90.80	-10.30%	90.22	7.82%	108.13
	2002	-6.00%	85.51	-4.09%	86.60	6.88%	115.83
	2003	-0.40%	85.17	-2.03%	84.85	6.24%	123.29
	2004	1.07%	86.08	4.80%	89.03	-6.11%	115.99
	2005	1.93%	87.76	3.83%	92.51	-8.52%	106.51
	2006	-3.22%	84.98	-1.42%	91.20	17.00%	126.25
	2007	-0.25%	84.77	-0.51%	90.74	9.88%	139.36
During IR	2008	-1.94%	83.14	-1.96%	88.98	-3.03%	135.21
	2009	-1.73%	81.72	-1.89%	87.31	1.51%	137.26
	2010	0.52%	82.15	1.78%	88.87	-2.43%	133.96
	2011	-2.96%	79.76	-3.48%	85.83	5.37%	141.35
Average Annual Growth Rates							
Whole Period	2000-2011	-2.06%		-1.39%		3.15%	
Pre-IR	2000-2007	-2.36%		-1.39%		4.74%	
During IR	2007-2011	-1.53%		-1.39%		0.35%	

The industry study group and seven company sub-group's labour quantity sub-indices both fell over the study period, while EGD's labour quantity sub-index grew. EGD's labour quantity sub-index grew at an average annual rate of 3.15%, which was the second-highest of the industry study group. However, EGD decreased their labour quantity sub-index growth rate over the more recent 2007 to 2011 period, compared to the earlier 2000 to 2007 period. In contrast, the industry study group's labour quantity sub-index increased in the more recent 2007 to 2011 time period compared to the earlier 2000 to 2007 time period and the seven company sub-group's labour quantity index remained constant.

Figure B-6: Materials Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[119] (2000-2011)

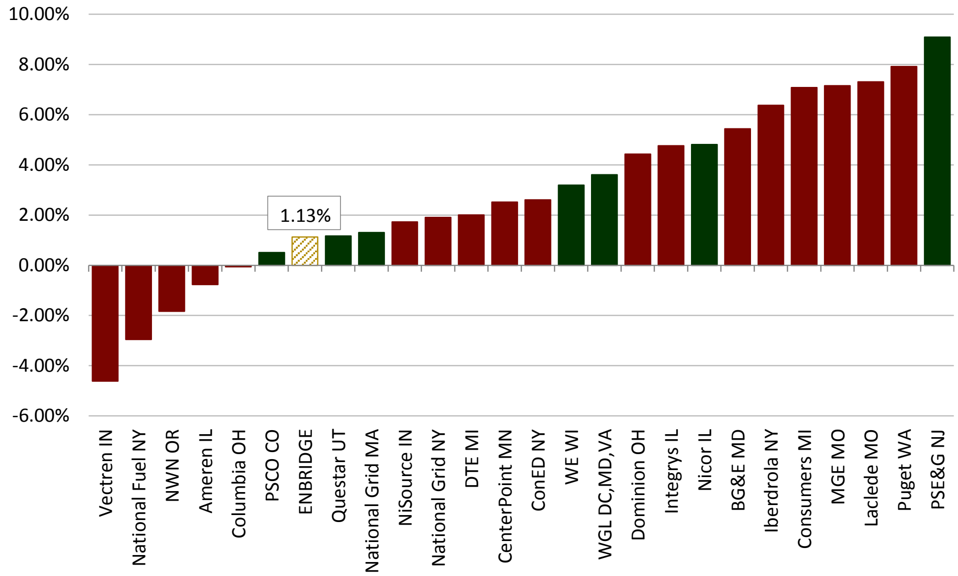
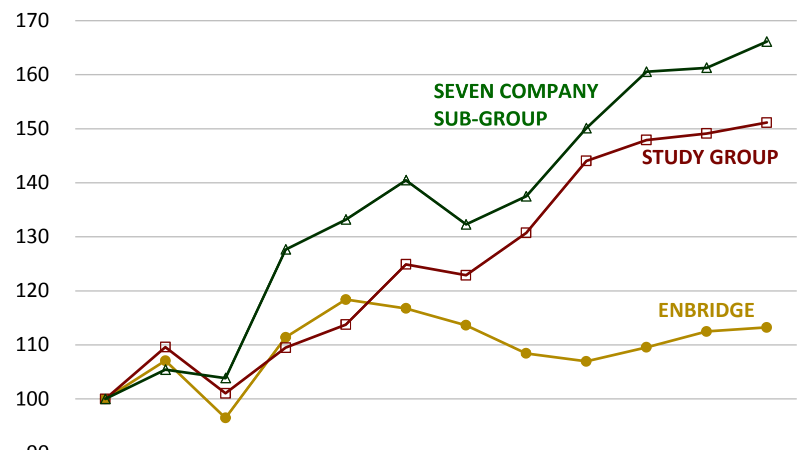


Figure B-7: Materials Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000=100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EGD	100	107	97	111	118	117	114	108	107	110	112	113
Industry Study Group	100	110	101	109	114	125	123	131	144	148	149	151
7 Company Sub-Group	100	105	104	128	133	140	132	137	150	161	161	166

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119 The companies in the seven company sub-group are indicated by green shading.

Figure B-8: Materials Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		7 Company Sub-Group		EGD	
		Materials Quantity Growth Rate	Materials Quantity Index	Materials Quantity Growth Rate	Materials Quantity Index	Materials Quantity Growth Rate	Materials Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	9.17%	109.60	5.27%	105.41	6.84%	107.07
	2002	-8.13%	101.05	-1.48%	103.86	-10.40%	96.50
	2003	8.03%	109.50	20.63%	127.65	14.36%	111.41
	2004	3.81%	113.75	4.24%	133.18	6.09%	118.40
	2005	9.36%	124.92	5.32%	140.47	-1.40%	116.75
	2006	-1.64%	122.89	-6.00%	132.29	-2.72%	113.63
	2007	6.19%	130.74	3.86%	137.49	-4.67%	108.45
During IR	2008	9.69%	144.05	8.78%	150.11	-1.39%	106.95
	2009	2.65%	147.92	6.72%	160.55	2.41%	109.56
	2010	0.82%	149.13	0.45%	161.27	2.64%	112.49
	2011	1.34%	151.15	2.96%	166.12	0.67%	113.24
Average Annual Growth Rates							
Whole Period	2000-2011	3.76%		4.61%		1.13%	
Pre-IR	2000-2007	3.83%		4.55%		1.16%	
During IR	2007-2011	3.63%		4.73%		1.08%	

EGD's materials quantity sub-index grew at an average rate of 1.13%, which was lower than both the industry study group and seven company sub-group averages of 3.76% and 4.73%, respectively. EGD's materials quantity sub-index was in the second lowest quartile of the industry study group. EGD and the industry study group decreased their materials quantity sub-index growth rate over the more recent 2007to 2011 period, compared to the earlier 2000 to 2007 period. In contrast, seven company sub-group's materials quantity sub-index increased in the more recent 2007 to 2011 time period compared to the earlier 2000 to 2007 time period.

Figure B-9: Capital Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[120] (2000-2011)

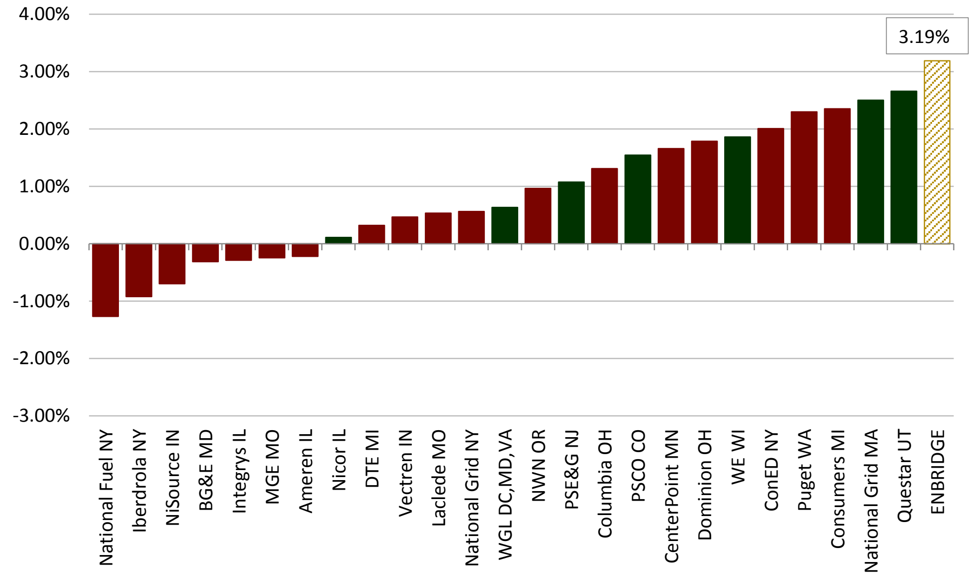
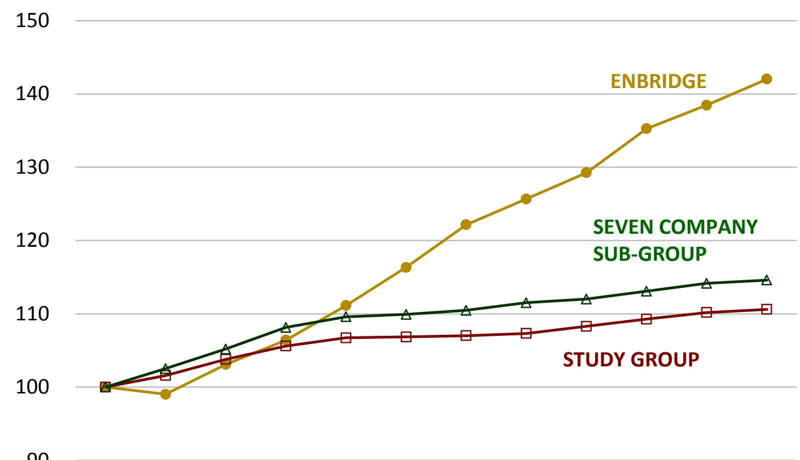


Figure B-10: Capital Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group (Year 2000=100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
EGD	100	99	103	106	111	116	122	126	129	135	138	142
Industry Study Group	100	102	104	106	107	107	107	107	108	109	110	111
7 Company Sub-Group	100	103	105	108	110	110	110	112	112	113	114	115

120 The companies in the seven company sub-group are indicated by green shading.

Figure B-11: Capital Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		7 Company Sub-Group		EGD	
		Capital Quantity Growth Rate	Capital Quantity Index	Capital Quantity Growth Rate	Capital Quantity Index	Capital Quantity Growth Rate	Capital Quantity Index
	2000		100.00		100.00		100.00
	2001	1.57%	101.59	2.49%	102.52	-0.99%	99.02
	2002	2.15%	103.79	2.58%	105.19	4.04%	103.10
	2003	1.73%	105.60	2.76%	108.14	3.16%	106.41
	2004	1.06%	106.72	1.34%	109.60	4.35%	111.14
	2005	0.12%	106.85	0.29%	109.92	4.57%	116.33
	2006	0.16%	107.02	0.50%	110.47	4.89%	122.16
Pre-IR	2007	0.29%	107.33	0.94%	111.52	2.83%	125.67
	2008	0.90%	108.30	0.44%	112.01	2.80%	129.25
	2009	0.90%	109.28	0.96%	113.09	4.56%	135.27
	2010	0.82%	110.19	0.94%	114.16	2.34%	138.48
During IR	2011	0.39%	110.61	0.38%	114.60	2.53%	142.03
Average Annual Growth Rates							
Whole Period	2000-2011	0.92%		1.24%		3.19%	
Pre-IR	2000-2007	1.01%		1.56%		3.26%	
During IR	2007-2011	0.75%		0.68%		3.06%	

EGD's capital quantity sub-index grew at an average annual rate of 3.19%, which was higher than all other companies in the industry study group. EGD, the industry study group, and the seven company sub-group all decreased their capital quantity sub-index growth rate over the more recent 2007 to 2011 period, compared to the earlier 2000 to 2007 period.

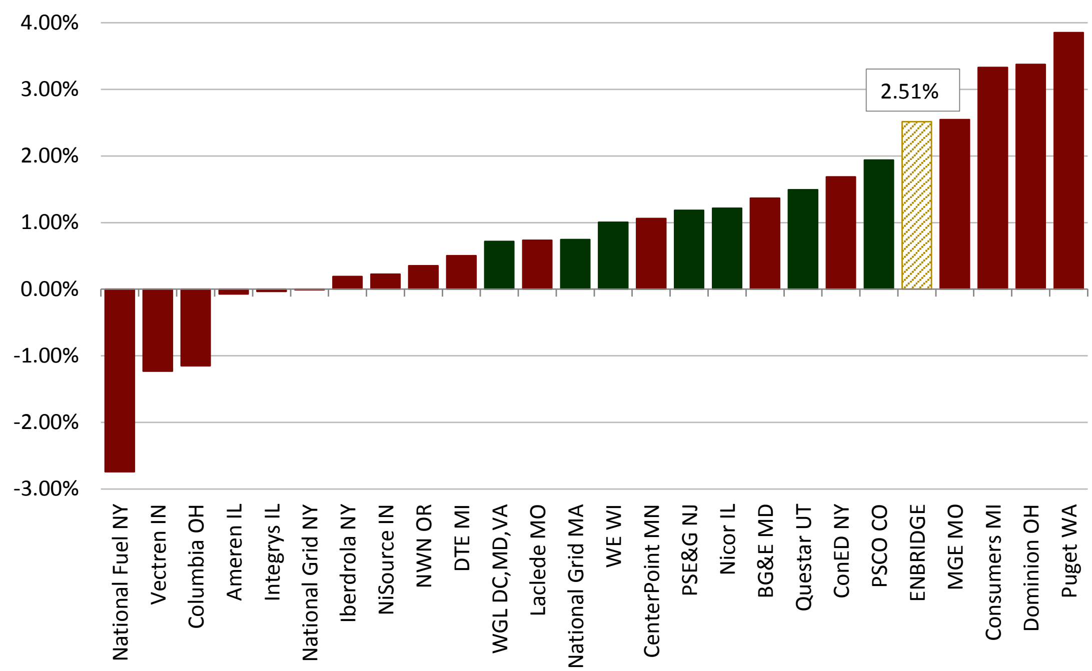
For the 25 company industry study group, the materials quantity sub-index grew at the fastest rate, 3.76%, followed by the capital quantity sub-index, which grew at an average rate of 0.92%, and the labour quantity sub-index, which decreased (declined) at an average annual rate of 2.06%. The sub-index growth rates were similar for the seven company sub-group; the materials quantity sub-index grew at the fastest rate, 4.61%, followed by the capital quantity sub-index, which grew at an average rate of 1.24%, and the labour quantity sub-index, which decreased (declined) at an average annual rate of 1.39%. In contrast, for Enbridge, the capital quantity sub-index grew at the fastest rate, 3.19%, followed by the labour quantity sub-index, which grew at an average rate of 3.15%, and the materials quantity sub-index, which grew at an average rate of 1.13%. As noted in the Output Index

Methodology section, Enbridge's faster output growth helps explain its greater utilization of capital and labour inputs.

F. TFP Input Index Calculation and Results

TFP input quantity indexes and annual growth rates are determined for each company by calculating a cost-weighted average of the input quantity growth rates of the sub-indexes (labour, materials, capital) for each year. Cost weights for each sub-index are developed for each year based on the share labour, materials and capital costs relative to the total costs. Annual input quantity growth rates for each year are calculated as the average growth in the input quantity sub-indexes weighted by the input sub-index cost weights using the Tornqvist-Theil methodology.[121] The industry input quantity index is determined by calculating a cost weighted average input quantity growth rate across all companies in the industry study group for each year. The TFP input quantity index and growth rates for EGD, the industry study group, and the seven company sub-group are shown in the following figures.

Figure B-12: TFP Input Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-group[122] (2000-2011)



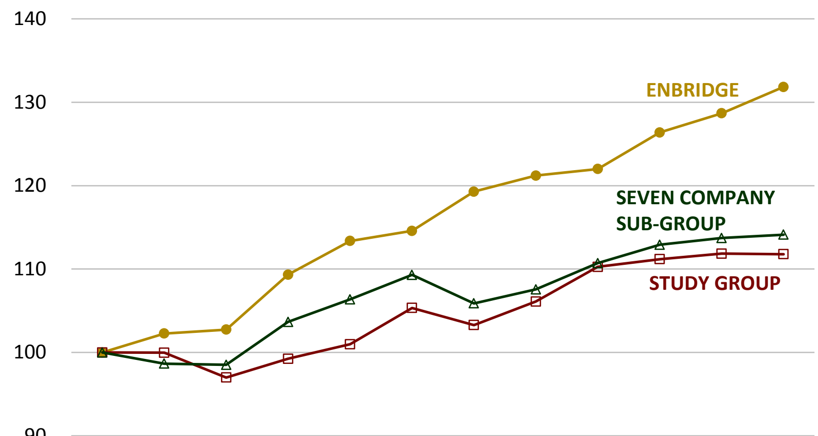
121 In a Tornqvist-Theil index, the growth rates are calculated as the difference in natural logarithms of successive observations of the components.

122 The companies in the seven company sub-group are indicated by green shading.

As shown by Figure B-12, 20 of the 26 companies (including EGD) experienced positive TFP input index growth rates over the 2000 to 2011 study period. Between 2000 and 2011, EGD's input index grew at a faster rate than all but four companies in the industry study group, and at a faster rate than all the companies in the seven company sub-group. EGD's higher TFP input index growth rate is due to EGD's comparatively greater capital and labour sub-index growth rates. As will be discussed in the Output Index Methodology section, EGD has experienced more rapid customer growth than most of the companies in the industry study group, which helps explain EGD's higher capital and labour growth relative to the industry study group.

Figure B-13: TFP Input Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	102	103	109	113	115	119	121	122	126	129	132
Study Group	100	100	97	99	101	105	103	106	110	111	112	112
7 Co. Sub-Group	100	99	99	104	106	109	106	108	111	113	114	114

Figure B-14: TFP Input Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	-0.03%	99.97	-1.35%	98.66	2.25%	102.27
	2002	-3.02%	97.00	-0.14%	98.52	0.46%	102.74
	2003	2.28%	99.24	5.09%	103.66	6.21%	109.33
	2004	1.75%	100.99	2.57%	106.36	3.63%	113.37
	2005	4.22%	105.34	2.73%	109.30	1.05%	114.57
	2006	-1.97%	103.29	-3.17%	105.89	4.03%	119.29
	2007	2.68%	106.10	1.56%	107.56	1.59%	121.20
During IR	2008	3.85%	110.26	2.88%	110.71	0.66%	122.00
	2009	0.84%	111.19	1.97%	112.91	3.52%	126.37
	2010	0.59%	111.85	0.72%	113.72	1.81%	128.68
	2011	-0.06%	111.79	0.35%	114.13	2.42%	131.83
Average Annual Growth Rate							
Whole Period	2000-2011	1.01%		1.20%		2.51%	
Pre-IR	2000-2007	0.85%		1.04%		2.75%	
During IR	2007-2011	1.31%		1.48%		2.10%	

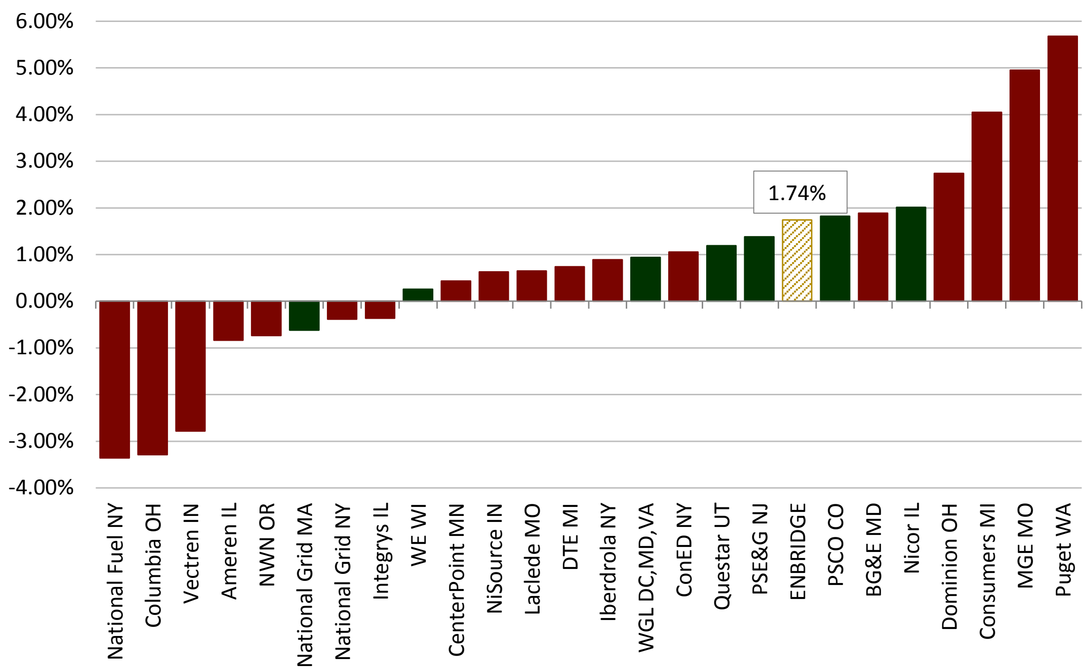
Although EGD's overall TFP input index growth rate has been higher than the industry study group and the seven company sub-group, EGD's TFP input index growth rate was lower during the IR period (2007-2011) compared to the pre-IR period (2000-2007).[123] In contrast, the industry study group's TFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 1.31%, which was an increase of 0.46% over the industry study group's TFP input quantity growth rate from 2000 to 2007. In addition, the seven company sub-group's TFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 1.48%, which was an increase of 0.44% over the seven company sub-group's TFP input quantity growth rate from 2000 to 2007.

[123] EGD's pre-IR Input Index grew by an average annual rate of 2.75%; the Input Index growth rate averaged 2.10% during the IR period.

G. PFP Input Index Methodology and Results

The PFP input quantity index is an aggregation of labour and materials quantity sub-indexes and differs from the TFP input quantity index in that the PFP input quantity index excludes capital quantities. PFP input quantity indexes and annual growth rates are determined for each company by calculating a cost-weighted average of the input quantity growth rates of the sub-indexes (labour, materials) for each year. Cost weights for each sub-index are developed for each year based on the share labour and materials costs relative to the total costs. Annual input quantity growth rates for each year are calculated as the average growth in the input quantity sub-indexes weighted by the input sub-index cost weights using the Tornqvist-Theil methodology.[124] The industry input quantity index is determined by calculating a cost weighted average input quantity growth rate across all companies in the industry study group for each year. The PFP input quantity index and growth rates for EGD, the industry study group, and the seven company sub-group are shown in the following figures.

Figure B-15: PFP Input Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-group[125] (2000-2011)



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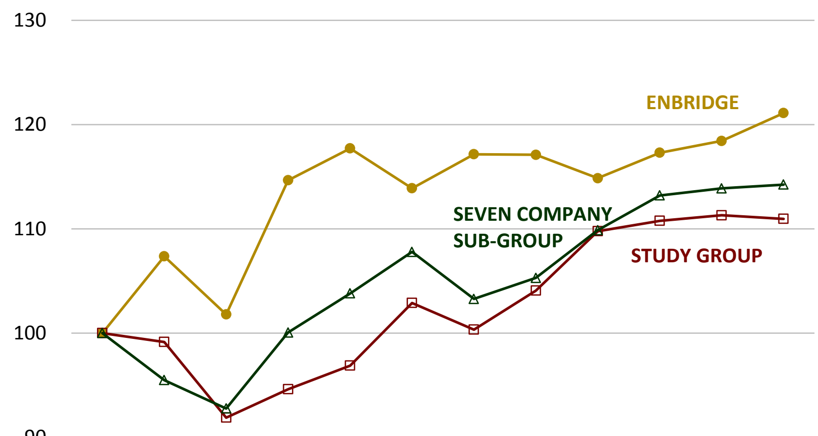
124 In a Tornqvist-Theil index, the growth rates are calculated as the difference in natural logarithms of successive observations of the components.

125 The companies in the seven company sub-group are indicated by green shading.

As shown by Figure B-15, 18 of the 26 companies (including EGD) experienced positive PFP input index growth rates over the 2000 to 2011 study period.

Figure B-16: PFP Input Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	107	102	115	118	114	117	117	115	117	118	121
Study Group	100	99	92	95	97	103	100	104	110	111	111	111
7 Co. Sub-Group	100	95	93	100	104	108	103	105	110	113	114	114

Figure B-17: PFP Input Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index	Input Quantity Growth Rate	Input Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	-0.85%	99.16	-4.61%	95.50	7.10%	107.36
	2002	-7.61%	91.89	-2.90%	92.77	-5.32%	101.80
	2003	2.92%	94.62	7.56%	100.06	11.90%	114.66
	2004	2.37%	96.88	3.68%	103.81	2.63%	117.71
	2005	6.02%	102.89	3.77%	107.79	-3.30%	113.90
	2006	-2.51%	100.34	-4.28%	103.28	2.82%	117.16
	2007	3.66%	104.08	1.93%	105.29	-0.04%	117.11
During IR	2008	5.33%	109.77	4.25%	109.87	-1.94%	114.86
	2009	0.91%	110.78	2.99%	113.21	2.11%	117.30
	2010	0.48%	111.31	0.60%	113.89	0.96%	118.44
	2011	-0.31%	110.97	0.31%	114.24	2.23%	121.11
Average Annual Growth Rates							
Whole Period	2000-2011	0.95%		1.21%		1.74%	
Pre-IR	2000-2007	0.57%		0.74%		2.26%	
During IR	2007-2011	1.60%		2.04%		0.84%	

Although EGD's overall PFP input index growth rate has been higher than the industry study group and the seven company sub-group, EGD's PFP input index growth rate was lower during the IR period (2007-2011) compared to the pre-IR period (2000-2007).[126] In contrast, the industry study group's PFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 1.60%, which was an increase of 1.03% over the industry study group's PFP input quantity growth rate from 2000 to 2007. In addition, the seven company sub-group's PFP input quantity growth rate from 2007 to 2011 (EGD's 1st Generation IR period) was 2.04%, which was an increase of 1.30% over the seven company sub-group's TFP input quantity growth rate from 2000 to 2007.

126 EGD's pre-IR Input Index grew by an average annual rate of 2.26%; the Input Index growth rate averaged 0.84% during the IR period.

III. OUTPUT INDEX METHODOLOGY

A. Introduction

In economic terms, output is the "quantity of goods or services produced in a given time period, by a firm, industry, or country,"[127] whether consumed or used for further production. An output index measures trends in the goods and services produced by the company, industry, or economy. Applied to a natural gas distribution company, outputs are generally considered to include metrics such as number of customers, quantities of gas delivered to customers, and deliveries at peak demand conditions. In this case it is appropriate that the Output Index is based on the number of customers served.

The gas distribution output index that Concentric developed for this study is derived from sub-indexes of the number of residential and non-residential customers served, for EGD and each of the industry study group companies. The output index for EGD and each industry study group company is determined by weighting the output sub-indexes by annual company-specific distribution revenue shares (excluding gas cost). To determine the overall industry Study Group output index across all industry study group companies, the relative share of each company's annual distribution revenues are used to weight the output index by company and year.

B. Output Quantity

The output quantity index measures trends in the amount of output produced by EGD and the companies in our industry study group. The measures of output included in the output index are: (1) Residential customer counts, and (2) Non-Residential customer counts.[128]

The two customer count sub-indexes of the output index measure the growth rates in the annual number of customers for the Residential and Non-Residential customer segments. The customer count sub-index for EGD is based on customer data by rate class as reported by the Company. The customer count sub-index for the industry study group is based on annual data, by customer class from Form EIA-176, supplemented with data obtained from the Annual LDC Reports.[129]

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[127] Alan Deardorff, Deardorff's Glossary of International Economics.

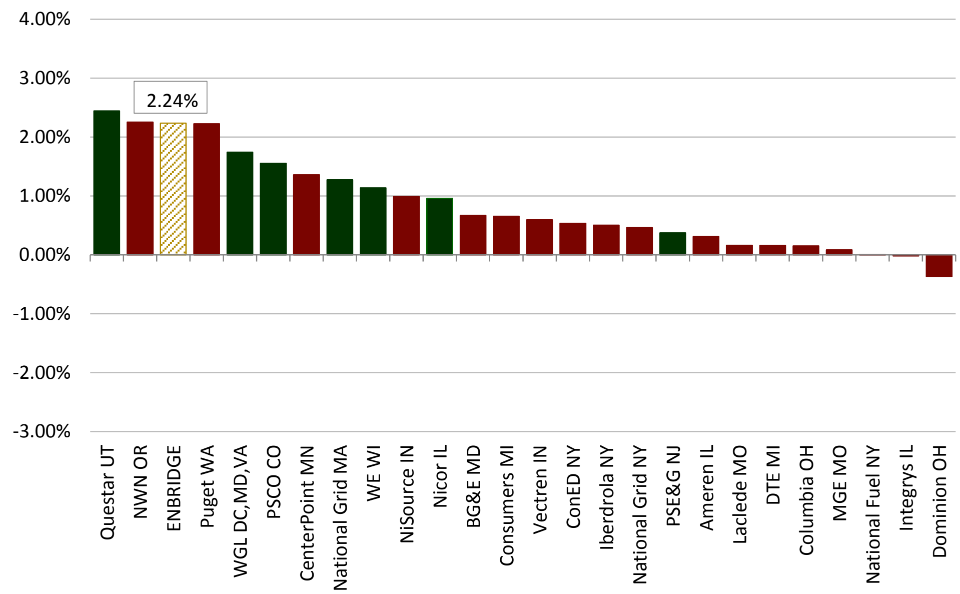
[128] The Residential customer segment for EGD includes Rate 1. Non-Residential includes all other EGD firm tariffed rates. For the 25 industry study group companies Residential and Non-Residential (i.e., Commercial/Industrial/Other) is as reported in the Form EIA-176.

[129] The measures of output for each customer segment combine data from customers that receive (a) bundled sales and delivery service, and (b) unbundled delivery service from the gas distribution company.

C. Output Index Calculation and Results

To develop the output index for each company, the Residential and Non-Residential customer segment growth rates are weighted by the annual relative shares of company-specific distribution revenues.[130,131] Once output indices are developed for each company in the industry study group, a weighted average is calculated based on each company's total distribution revenues for each year of the study. The EGD, industry study group, and seven company sub-group output quantity indices and growth rates are shown in Figures B-18, B-19, and B-20.

Figure B-18: Output Quantity Index Growth for EGD, the Industry Study Group, and the Seven Company Sub-Group[132] (2000-2011)



As shown in Figure B-18, almost all study group companies (23 out of 25) experienced an increase in output quantities (i.e., number of customers) over the 2000 to 2011 study period. EGD's output quantities grew at a faster rate over this period than all except two companies

130 Distribution revenue is the component of total revenues that is associated with unbundled delivery service. Supply revenue, which is associated with bundled gas supply service, is the other major component of total revenues.

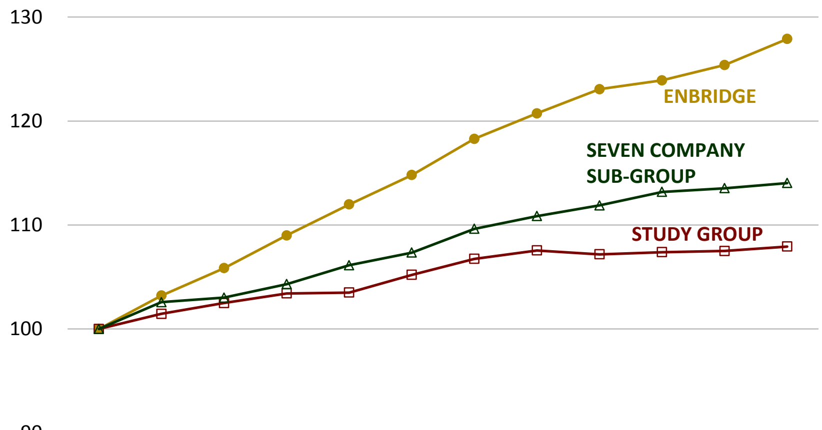
131 Most gas distribution companies, including EGD, offer a choice of either bundled sales service or unbundled distribution service to some or all of its customers. Those customers who elect the unbundled distribution service must obtain gas supply services from competitive suppliers; customers who elect the bundled sales service receive both distribution and gas supply services from the (regulated) distribution company.

132 The companies in the seven company sub-group are indicated by green shading.

in the industry study group, and faster than all except one company in the seven company sub-group. Enbridge's relatively high customer count growth is consistent with the rapid population growth in the Toronto area relative to other metropolitan areas in North America.

Figure B-19: Output Quantity Index Annual Trend for EGD, the Industry Study Group, and the Seven Company Sub-Group

(Year 2000 = 100)



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Enbridge	100	103	106	109	112	115	118	121	123	124	125	128
Study Group	100	101	102	103	104	105	107	108	107	107	108	108
7 Co. Sub-Group	100	103	103	104	106	107	110	111	112	113	114	114

Figure B-20: Output Quantity Index Results Table for EGD, the Industry Study Group, and the Seven Company Sub-Group

		Industry Study Group		Seven Company Sub-Group		EGD	
		Output Quantity Growth Rate	Output Quantity Index	Output Quantity Growth Rate	Output Quantity Index	Output Quantity Growth Rate	Output Quantity Index
Pre-IR	2000		100.00		100.00		100.00
	2001	1.45%	101.46	2.55%	102.58	3.16%	103.21
	2002	1.01%	102.50	0.42%	103.01	2.52%	105.85
	2003	0.90%	103.42	1.25%	104.31	2.93%	108.99
	2004	0.08%	103.51	1.73%	106.13	2.70%	111.97
	2005	1.63%	105.21	1.14%	107.34	2.49%	114.80
	2006	1.45%	106.75	2.11%	109.63	2.99%	118.28
	2007	0.75%	107.55	1.12%	110.86	2.05%	120.73
During IR	2008	-0.34%	107.18	0.92%	111.89	1.91%	123.06
	2009	0.20%	107.39	1.15%	113.18	0.68%	123.91
	2010	0.10%	107.50	0.32%	113.54	1.19%	125.39
	2011	0.40%	107.93	0.43%	114.03	1.98%	127.89
Average Annual Growth Rates							
Whole Period	2000-2011	0.69%		1.19%		2.24%	
Pre-IR	2000-2007	1.04%		1.47%		2.69%	
During IR	2007-2011	0.09%		0.70%		1.44%	

Figure B-20 demonstrates that the industry group, the seven company sub-group and EGD all experienced decreases in output quantity growth rates during 2007 to 2011, compared to 2000 to 2007. The industry study group output growth rate decreased from 1.04% to 0.09%, the seven company sub-group output growth rate decreased from 1.47% to 0.70%, and EGD's output growth rate decreased from 2.69% to 1.44%. The decrease in output growth rates is due to slowing customer growth in recent years, likely due to the impact of the recent economic downturn on the housing industry generally and especially on housing starts.

APPENDIX C: EXECUTIVE BIOGRAPHIES

James M. Coyne, Senior Vice President, is an industry expert who provides financial, regulatory, strategic, and litigation support services to clients in the power and gas utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, cross-border trade, rate and regulatory policy, capital cost determinations, valuations, fuels and power markets. He is a frequent speaker and author of numerous articles on the energy industry and regularly provides expert testimony before federal, state and provincial jurisdictions in the U.S. and Canada. He testifies on matters pertaining to the cost of capital, capital structure, business risk, alternative ratemaking mechanisms and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

James D. Simpson, Senior Vice President, has over 30 years of experience with regulatory relations, regulated pricing and business strategy; he has held senior executive positions at a natural gas utility and an entrepreneurial company providing a proprietary service to generating companies. As Chief Operating Officer for a major New England gas company, Mr. Simpson was responsible for all regulated business activities including Gas Supply, Operations, Engineering, Marketing and Sales, and Planning. His responsibilities in other positions have included business development, pricing strategy, regulatory affairs, analysis and planning. Mr. Simpson also held staff and director level positions at the Wisconsin Public Service Commission and the Massachusetts Department of Public Utilities; he has an M.S. in Economics from the University of Wisconsin and a B.A. in Economics from the University of Minnesota.

Melissa F. Bartos, Assistant Vice President, is a financial and economic consultant with more than fifteen years of experience in the energy industry. She has conducted comprehensive demand forecast analyses including data collection and validation; model building using various statistical and econometric approaches, and developing presentations, reports and testimony to communicate results. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony regarding natural gas demand forecasting issues. Ms. Bartos previously consulted with Reed Consulting Group and Navigant Consulting, Inc.; she has an M.S. in Mathematics (Statistics) from the University of Massachusetts at Lowell, a B.A. from the College of the Holy Cross in Worcester, MA, and is a member of the American Statistical Association.

Annexe B

STATE OF VERMONT
PUBLIC SERVICE BOARD

In Re Petition of Vermont Gas Systems, Inc., pursuant to 30 V.S.A. § 218d, for authority to implement an Alternative-Regulation Plan	)))	Docket No. _____

PREFILED TESTIMONY OF JAMES M. COYNE

Q1. State your name.

A1. James M. Coyne

Q2. What is your position, and by whom are you employed?

A2. My name is James M. Coyne, and I am employed by Lexecon as a Senior Managing Director providing consulting services to energy companies and public agencies regarding the natural gas and electric industries.

Q3. What is the purpose of your testimony?

A3. My testimony provides background on the work that Lexecon performed on behalf of Vermont Gas Systems, Inc. (to which I refer in my testimony as "VGS" or the "Company"), in consultation with the Department of Public Service (to which I refer as the "Department"), to evaluate alternative means by which VGS could be regulated. It also addresses policy and regulatory issues associated with the proposed Alternative-Regulation Plan (to which I refer sometimes as the "Plan", or generically as "Alt Reg"). My testimony is supplemented by that of my colleague, Charles Augustine, who will describe the components of the Plan, Exhibits VGS-CA-1 and VGS-CA-2, including specifically the "Earnings Sharing Mechanism" or "ESM" as well as the "Purchase Gas

Adjustment" clause or "PGA" proposed. Last, I address several of the criteria established by Section 218d on which the Board must make affirmative findings to approve the Plan, and I offer my observations about the value of alternative regulation in general.

Q4. What are your qualifications to sponsor the testimony you intend to present?

A4. Exhibit VGS-JMC-1 contains my resume, which provides the details of my qualifications. In summary, I have over 20 yeas of experience in consulting, operations and public policy in the energy and utilities industries. Over the past two years, I have worked with the Vermont Hydroelectric Power Authority, Vermont Gas Systems and the staff of the Department of Public Service providing an opportunity to gain additional perspective on Vermont's energy needs and policies.

I. <u>Background</u>

Q5. Begin as you propose by providing an overview of Lexecon's engagement by VGS and the work that Lexecon, VGS and the Department undertook to evaluate alternative regulation.

A5. As the Board is aware, in Docket No. 6928 the Board approved an Amended Memorandum of Understanding (or "MOU") that (among other requirements) obligated the Department and VGS to "work cooperatively to study and develop an alternative, long-term methodology for regulating VGS" and required VGS to retain a consultant to assist both parties in studying and developing a plan. In December of 2003, VGS with the advice and consent of the Department retained Lexecon to work with the parties to facilitate the study, research alternative regulation and draft models for consideration.

VGS, the Department and Lexecon undertook the work in phases, with each phase organized around a workshop. Lexecon first organized an initial workshop, the purpose of which was to examine the existing regulatory model, identify problem areas and discuss and attempt to reach consensus on the desirable attributes for an alternative model. Exhibit VGS-JMC-2 is the list of attributes that resulted from the workshop, which includes all of the criteria established by Section 218d. I should note that the list of attributes, beyond those in 218d, is a combination of consensus views and individual positions from the workshop discussions with the Company and Department. It was not our goal to achieve complete consensus, but rather to get the full range of desirable attributes on the table so we could understand the positions of both parties and introduce compatible solutions.

Following that workshop, Lexecon undertook research to examine alternative frameworks used to regulate other local-distribution companies (or "LDCs"). This phase concluded with a second workshop at which the parties discussed the regulatory models from other states that we found and analyzed them against the list of attributes that had been developed at the first workshop.

This workshop led the parties to focus on regulatory models that had PGAs and earnings-sharing mechanisms including those that addressed, in particular, system expansion. Exhibit VGS-JMC-3 is a copy of the report prepared by Lexecon for the second workshop, and four attachments (VGS-JMC3a-Alt Reg Plans; VGS-JMC-3b-Earnings Sharing Plans; VGS-JMC-3c- Earnings Sharing Mechanisms; and VGS-JMC-3d-Hedging Survey) , which provides in summary form the various regulatory models examined by Lexecon.

Lexecon next developed and presented "straw proposals" for examination by the parties at the third workshop. Following the workshop, we began to draft and the Company began to model two programs for alternative regulation that would include an ESM and a PGA.

I should point out several additional developments. First, the Department was interested in researching how regulators and LDCs in other jurisdictions viewed alternative regulation. As a result, we prepared a report, Exhibit VGS-JMC- 4, that provides information about how regulators and LDCs view alternative-regulation plans that have, among other features, PGAs and ESMs.

In addition, VGS became interested in the means by which its indirect parent, Gaz Métro Limited Partnership, is regulated in Québec. Subsequently, representatives of Gaz Métro and then representatives of the Régie d'Energie du Québec made presentations to the Department as well as the Board on that model of regulation.

As a result of this work, Lexecon prepared what became Attachments 1 and 2 to the proposed Alternative-Regulation Plan, a detailed description of how the ESM and PGA would function. As will be evident from reviewing these documents, with modifications the ESM and PGA proposed by the Company is similar to the one used by Gaz Métro Limited Partnership in Québec.

Q6. Summarize Lexecon's conclusions about the experience of other jurisdictions and the appropriateness of an alternative model for regulating VGS that includes an ESM and a PGA.

A6. We have found that states adopting alternative regulatory models believe there are benefits for consumers, regulators and the utilities. PGAs have been widely adopted in the regulation of gas cost recovery for natural gas utilities in the U.S. Our research has found that all states with gas utilities, with the exception of Vermont and Georgia (which has unbundled gas rates and introduced retail competition), have adopted PGA cost-recovery mechanisms. Our research further indicates eight states have adopted earnings-sharing mechanisms for base rates. There has been a growing consensus among regulators that movement from command-and-control regulation to incentive regulation is in the public interest. Based on our assessment of these programs and Vermont's objectives for alternative regulation (as forwarded in 30 V.S.A. 218d), we believe the proposed Plan is an appropriate model for VGS.

Q7. How do regulators and the regulated in other jurisdictions view their experiences with alternative regulation?

A7. The benefits of alternative regulatory models are typically judged against past practices and are difficult to measure with precision. For this reason, we interviewed a total of twenty-one individuals representing eight natural-gas companies and eight public agencies in seven states with Alt Reg programs, including ESM. Our objective, at the suggestion of the Department, was to seek direct feedback from those directly responsible for administering these programs. Through these survey interviews, we gathered responses on a series of related questions.

The consensus view was that Alt Reg programs were working to the benefit of the stakeholders. Respondents from all seven states surveyed expressed a reasonable degree of satisfaction with their PGA mechanisms. PGAs are generally designed to track and recover the commodity cost of gas plus related fixed charges for pipeline and storage costs and generally perform this function well. On the ESM programs, eight of those responding recommended these plans without qualification and six others with qualification. Only one recommended against the adoption of ESM, indicating it was not in the respondent's company's best interest.

Q8. Why do you believe that Alt Reg models have generally been met with acceptance?

A8. By and large these models have not strayed very far from familiar cost-of-service regulation, so checks and balances remain in place. Both regulators and utilities feel they can better dedicate limited staff resources to pressing policy or commercial issues without being bogged down in routine gas-cost adjustments or contentious rate cases. Utilities are incentivised under earnings-sharing mechanisms and multi-year rate agreements to operate more efficiently and pass some of these gains along to customers. Lower and more stable rates (in contrast to periodic, litigated rate cases) have been cited as tangible benefits for consumers. Utilities have cited such benefits as positive reaction from the investment community, lower regulatory compliance costs, better ability to execute longer-term business plans, and in some cases higher ROE's.

II. Statutory Criteria

Q9. I would now like to turn to several of the statutory criteria that are relevant to the Plan and specifically to an ESM and a PGA. Will the Plan establish a system of regulating VGS in which the Company will have, quoting, a clear incentive to provide least-cost energy service to its customers?

A9. Yes, and these incentives should be greater than under the prior rate-setting mechanism. Under the ESM, the Company will be effectively limited to its cost of service at the beginning of the plan plus inflationary annual increases. Should actual costs rise more rapidly than inflation, this will reduce future earnings. Conversely, should the Company drive costs lower than inflation, it will retain a portion of these gains. So the Company is penalized for allowing costs to exceed inflation and rewarded for driving them lower. This is a clear incentive against a reasonable benchmark that does not exist today. Under existing regulatory practice, the Company would be expected to recover its prudently incurred reasonable cost of service. Under ESM, the Company will remain subject to periodic full cost of service filings, so these regulatory thresholds still apply. Under ESM, the Company will be rewarded for identifying additional cost efficiencies as measured against inflation between cost of service filings. As an example, the Company's employee benefit costs have increased by an average rate of 7% over the past ten years. Under ESM, these costs will be measured against inflation less the productivity factor, creating a new incentive to manage health care and related expenditures.

Under the PGA, the Company will recover prudently-incurred gas costs as it has in the past, but more efficiently. The incentives to purchase gas under the PGA at least cost remain as they have been: the negative consequences of a finding of imprudence in the periodic review of the Company's gas purchases under the proposed PGA; and the loss of load to alternate fuels. In both cases, earnings would suffer.

Q10. Do you think that the rates for VGS services that will result from implementation of the Plan will be just and reasonable to all classes of customers?

A10. Yes. If one defines just and reasonable as reflecting the prudently incurred reasonable operating expenses and long term capital commitments, one could argue that rates will be more reflective of the actual costs of serving each customer class as rates are unbundled under the proposed Plan. Vermont Gas is a relatively small gas company with limited opportunity for cost reduction in contrast to larger utilities, but on the margin, the Company will have a new incentive to drive costs lower.

Gas costs will reflect actual gas costs, so outside of a finding of imprudence the gas portion of rates would meet this standard. Base rates will start out at the cost of service and will then move with inflation (less productivity) or the difference between actual costs and inflation if lower.

One could argue that a program that would allow a rate over actual cost fails to meet the just-and-reasonable standard. This only occurs, however, when the Company has been successful in creating operating cost reductions in excess of those built into the inflation/productivity index from past years providing the opportunity for earnings sharing in subsequent rate periods. The corresponding argument is that the Company is incented to drive costs lower, so earnings sharing drives costs and rates lower over time. Our research indicates this latter scenario has been experienced or expected by those states we have surveyed. A key feature of this program will be to measure its actual performance over time to ensure this is the case for VGS. Over the initial three year program, the Board will have the opportunity to measure the Plan's effectiveness. Multiple years of earnings sharing would suggest success. Continuous periods of required revenues in excess of the rate cap would suggest a re-examination of the Plan's key parameters, or any unusual operating circumstances.

Q11. Do you think that the Plan has any impacts that will adversely affect VGS's obligation to deliver safe and reliable service?

A11. No. The PGA mechanism should have no direct impact on safety or reliability. The ESM is more directly relevant.

Of concern might be a utility so motivated to reduce costs that it compromises on system maintenance to impact negatively safety or service reliability. A few factors mitigate against such behavior.

First, the direct revenue loss or costs of system disruptions, gas leaks and related outages run counter to achieving or exceeding the targeted ROE. Second, the liability in terms of financial consequences and company image run counter to achieving earnings targets. Finally, in many jurisdictions, as in Vermont, Service Quality Requirements (SQRs) are established to ensure these metrics are monitored and rewarded or penalized in conjunction with the earnings sharing mechanism.

We questioned the survey respondents on the issue of service quality, and this issue was an issue of concern to the regulatory staff we questioned. All respondents indicated that service quality had either remained the same or improved under the Alt Reg program.

Q12. Will the Plan promote improvements to VGS's quality of service, reliability and innovation in service choices?

A12.

Service-quality thresholds are currently in place for VGS through the SQRP. The Plan does not weaken SQRP, as it contains its own financial repercussions, and the Company is proposing an additional measure. Service choices should ultimately be improved with unbundled rates and clear price signals, allowing Vermont Gas to offer various fixed-price and payment options to its customers. Under the ESM framework, the Company has an incentive to grow its system and further penetrate its existing markets. It can only accomplish this by delivering safe and reliable service to its customers.

The Company will be more successful under ESM if it retains existing customers, further penetrates its markets and grows its system by developing innovative service offerings. The Company is competing against fuel oil, propane and electricity to win new accounts and expand utilization from existing customers. To do so successfully, Vermont Gas must customize service offerings that meet or exceed competitive service offerings. Innovation in pricing, billing, on-site service, new customer hookups, and energy efficiency products are tools used to retain existing load and attract new customers. I understand that the Company will be offering a fixed firm service and an interruptible tariff service in the near future. Under the ESM, the Company should be fully motivated to retain existing customers and attract new business to achieve stretch ROE objectives.

Q13. Does the Plan establish a reasonably balanced system of risks and rewards that will encourage VGS to operate as efficiently as possible using sound management practices?

A13.

Under the proposed regulatory framework, the Company and ratepayers will be rewarded for improvements in operating efficiency under the ESM. Conversely, less efficient operations which increase costs will reduce earnings and cause the Company to under-perform against the target ROE. The PGA will improve the efficiency by which the Company and customers see rate adjustments to reflect ongoing market conditions. Under the PGA, wholesale gas markets will continue to be the primary driver impacting gas costs.

The Company will provide customers with reliable, market-based gas supplies by employing hedging, storage and contracting tools to smooth out unnecessary market volatility and ensure deliverability during peak demand periods. Company management practices will be subject to regulatory scrutiny at several recurring intervals: the annual Gas Supply Plan review, quarterly updates, and monthly PGA filings; the annual System Expansion Plan review; and periodic rate cases. There are many checks and balances in the proposed Plan and ample opportunity for Board and Department oversight of VGS' operations. Ultimately, we expect this process to be a more efficient one than current practice.

Q14. Last, will the Plan provide a reasonable opportunity, under sound and economical management, for VGS to earn a fair rate of return, and if your answer is yes, is the Company's opportunity to earn a fair return consistent with flexible design of alternative regulation and inclusion of effective financial incentives?

A14.

The very nature of the proposed plan is designed to achieve these objectives. Under the ESM, the Company will have a target rate of return adjudicated in periodic rate cases. These rate cases will be far fewer than current practice. Between rate cases, which can ultimately be extended to five years or longer (the currently proposed interval is 3 years, followed by two potential two year extensions), the Company will have the opportunity to earn a fair rate of return and also have the direct financial incentive to stretch that return through delivery of operational or financial excellence that exceeds historic performance (as measured by the productivity factor and inflation). In doing so, customers will benefit through their portion of any shared savings.

The program design is flexible in that the Company, with its inherent knowledge of the best opportunities to manage costs or expand revenues, will be fully motivated to identify and pursue these steps without regulatory intervention. The Board and Department will be able to monitor the results of both the PGA and ESM at periodic intervals and make adjustments to either program if deemed necessary to achieve regulatory or policy objectives. In fact, we would expect a learning process to occur for both the Company and the Board with this program, with the potential to implement program refinements over time.

Q15. Overall, how does Lexecon view alternative models of regulation as compared to traditional, cost-of-service regulation?

A15. We view these models as logical extensions of cost-of-service ratemaking models. Unlike the more dramatically restructured, wholesale-power markets where cost of service has been replaced by competitive market forces with market monitoring, Alt Reg models remain linked to a cost-of-service framework.

These programs are still in the formative stages. Regulatory agencies and companies have negotiated programs that leave room for success without inviting outcomes that stray too far from cost-of-service outcomes. Ongoing experience with these programs will improve confidence and allow for broader "exposure" to market oriented solutions within the regulatory framework. Higher and more volatile energy prices should hasten the speed at which policymakers and regulators look to alternative forms of regulation to promote operational efficiency and innovation in service offerings for utilities under their jurisdiction.

IV. Conclusions

Q16. Summarize your testimony.

A16. Lexecon, in collaboration with the Company and the DPS, has investigated alternative means by which VGS could be regulated. This investigation consisted of three principal components: an evaluation of current and past models in Vermont; an examination of alternative regulatory models employed in other states; and a survey of regulators and utility staff responsible for administering these programs. This process led to the proposed Plan submitted by the Company in this proceeding.

Our research has found that alternative regulatory models including earnings sharing exist in eight states, while PGAs exist in all states with regulated gas utilities except Georgia and Vermont. These programs are working to the reasonable satisfaction of the principal stakeholders and producing benefits for consumers, utilities and regulators. We find the proposed Plan to be consistent with Vermont's objectives for Alt Reg outlined in 30V.S.A. 218d.

The monitoring opportunities in the Plan leave the Board with its full powers of regulatory oversight, albeit with a "lighter hand" between rate cases. Most such Plans are modified over time through the benefit of learning on both sides. This Plan represents an evolutionary step from prior regulatory practices and the interim MOU and brings Vermont's regulatory practices more in line with national trends.

Q17. Does this conclude your testimony?

A17. Yes.

STJ.206730.1
STJ.210834.1

Annexe C

STIMULATING INNOVATION ON BEHALF OF CANADA'S ELECTRICITY AND NATURAL GAS CONSUMERS

2015 UPDATE

PREPARED FOR
CANADIAN GAS ASSOCIATION
CANADIAN ELECTRICITY ASSOCIATION

MAY, 2015

CONCENTRIC ENERGY ADVISORS

WWW.CEADVISORS.COM

TABLE OF CONTENTS

This paper was prepared by Robert Yardley, Jr. and James Coyne, with research assistance from Alison Bogdonoff, of Concentric Energy Advisors in collaboration with the Canadian Gas Association and the Canadian Electricity Association.

SECTION 1:
EXECUTIVE SUMMARY

As discussed in our August 2014 report innovation in the natural gas and electric utility industries promises benefits for customers in the form of improved reliability, energy cost savings, environmental benefits, and economic growth. An increased commitment to rate-payer funded innovation by utilities will support the testing and deployment of new technologies, products and services with associated business processes and models that deliver value to customers. The advances could include more efficient end-use equipment, low-emission customer-sited generation, energy storage, integrated gas/electricity solutions like micro combined heat and power, and a "smart energy network"[1] that integrates emerging technologies in a way that preserves the reliability and resiliency of the distribution system. Such innovations can provide cleaner and less expensive energy services to Canadian households and businesses while creating jobs, bolstering Canadian competitiveness, and promoting Canada's position among global energy leaders.

Our 2014 report offered a framework to consider the roles for government, utilities and other private-sector entities in innovation. We examined the roles that Canada's utilities and regulators can play to promote innovation, particularly where the public benefits from innovation are large enough to justify public funding and where the financial rewards for the private sector are not large enough to compensate for development risks. Ratepayer funding can be used to unlock and leverage funding from public and private sources that can be combined to ensure that customers benefit from research, development and deployment (RD&D) activities in the utility industry.

This 2015 Update presents regulatory and other current drivers of innovation in the electric and natural gas industries, and the challenges that will be faced by utilities (focusing on the distribution segment). Concentric presents several case studies organized into three distinct categories: (1) new innovation programs that have been announced within this past year, (2) new projects that have received funding, and (3) results of demonstration or other innovation efforts that have been recently completed. The case studies provide a deeper dive into specific financing sources, approaches and expected benefits from these programs or projects.

The innovation projects are sponsored by utilities and public entities that solicit, screen, select and fund energy-related R&D and innovation project proposals. Our research focused on jurisdictions – both in the United States and abroad – with histories of progressive approaches towards energy innovation and technology initiatives. It is evident that policymakers and regulators are taking an active interest in the role of innovation to address the daunting objectives of cleaner, more resilient, and cost-effective utility services. Many of the public and ratepayer-funded programs we cite remain in their formative stages, so the results are just starting to come in. Innovation by its nature is riskier than business as usual, so not all projects will be successful. Nonetheless, it will be important for policymakers, regulators and utilities to demonstrate tangible consumer benefits as these programs mature, even if substantial portions of these benefits spill over into the broader public domain.

SECTION 2:

2015 EMERGING INDUSTRY TRENDS

Whether viewed through the lens of cutting-edge product and service development or the imaginative retooling of companies' internal organizational and operating cost strategies, innovation drives competitiveness and inspires an atmosphere of workplace creativity. It's hard to imagine a company that would argue an innovative mind-set is not crucial to enterprise success.[2] – The Funding of Innovation in Canada

The focus of utility innovation at any particular point in time is driven by the major industry drivers. The current drivers include evolving regulatory models, economic goals, environmental and sustainability goals, market forces, and technology advances. Advancements in information technology and the ability to manage "big data" present both opportunities and challenges with respect to cyber security and the privacy of customer data. Safety also remains of paramount importance in both the natural gas and electricity industry.

In the electric industry, the "utility-of-the-future" concept has gained considerable momentum throughout the United States over the past year as the conversation has evolved from a relatively narrow focus on the increasing proliferation of roof-top solar and the impact of controversial "net metering" policies, to a broader discussion of whether electric distribution utilities will be transformed into grid "platforms" that enable the integration of all forms of distributed electricity energy resources (defined broadly to include distributed generation, storage, energy efficiency and microgrids) and provide transactional services to customers and third-parties. Interest in the utility-of-the-future is being driven by many of the same industry drivers, including goals to reduce the environmental footprint and improve end-to-end efficiency in the energy sector. Information and emerging energy technologies are key enablers as the cost of distributed and renewable generation are becoming more competitive and there is a concomitant need to monitor and control flows on the distribution network to be able to accommodate more of these resources while maintaining power quality and reliability. Energy storage, as it becomes more economical, is a potential contributor to the overall efficiency of the electric system by improving load factors throughout the supply chain and on customer premises.

The natural gas industry will contribute to a more efficient energy future as electricity and natural gas infrastructures and markets become increasingly integrated throughout the supply chain and include retail markets. Equipment manufacturers are responding to evolving market needs by developing more efficient natural gas end-use equipment that can take advantage of the current affordability of natural gas across North America. The potential efficiency benefits are becoming increasingly apparent to commercial and industrial customers that are candidates for combined heat and power (CHP) applications. There are other potential benefits of innovation that focus on the natural gas distribution network including enhancements to safety, reductions in methane emissions, and more efficient pipeline inspection and repair processes. As in the electric industry, there are opportunities to improve asset management, maintenance, and asset replacement processes through new data, systems and processes.

One of the building blocks of this new future is customer engagement and interest in new energy products and services that may be provided either by the utility or by third parties or by both working together as partners. This requires innovation and testing of new business models and new roles to be served by regulated distribution utilities. Ultimately, the ability to achieve the promises of this technology-driven future will depend on the ability of all stakeholders, including utilities, regulators, governments, and unregulated third party vendors to provide what customers want and value. This value includes the imperative that reliability, resiliency, security and safety of electric and natural gas distribution networks be maintained throughout any transition in business models and regulatory frameworks.

REGULATORY AND GOVERNMENT INITIATIVES

Not surprisingly, governments and regulators that are focused on utility-of-the-future business models recognize the importance of innovation in the utility sector and are including demonstration projects that will be funded by customers as an integral component of new regulatory frameworks. The imperative to move beyond "business as usual" utility models frames their discussion. This interest is prompted by major investments that will be required to add functionality to the distribution networks and by a recognition that these investments will not produce the desired efficiency gains if customers are not engaged. Innovation efforts by a utility enable it to evaluate emerging technologies and make informed investment decisions regarding those technologies.[3,4] Customer engagement is particularly important where the efficiency gains derive from "distributed energy resources" or "DERs" that include energy efficiency, demand response, acceptance of time-varying rate structures, distributed generation, and customer-sited energy storage.

The interest in new business models and regulatory frameworks in the United States follows the lead being set in the United Kingdom by the Office of Gas and Electricity Markets ("Ofgem"). Ofgem has implemented its latest iteration of incentive-based ratemaking (termed the Revenue = Incentives + Innovation + Outputs, or "RIIO," model) for gas and electric transmission and distribution companies, and the most recent framework includes new elements to foster innovation.[5] Ofgem recognized that even within the new incentive-based ratemaking framework, "research, development, trials and demonstration projects - the earlier stages of the innovation cycle - are speculative in nature and yield uncertain commercial returns."[6] Ofgem noted that the innovation stimulus is intended to "kick start" a cultural change at utilities.[7] Innovation funding is provided by customers since they will benefit from innovations.[8]

Interest in the utility-of-the-future has gained considerable steam in the United States over this past year. Three states are proceeding to consider changes in business models and regulatory frameworks in a comprehensive manner: California, Massachusetts and New York. Notably, each of these states has either made a major commitment to innovation and customer-funded demonstration projects or is working on a process for doing so. New York has received the most attention over the past year and is thus the subject of one of the case studies. As discussed in the case study, New York is particularly interested in testing new business models and for utilities to work collaboratively with third parties to engage customers as an integral element of its ambitious "Renewing the Energy Vision" or "REV" policy proceeding.

Two other states are addressing many of the same issues: Hawaii and Minnesota. Hawaii is a unique case because of its archipelago cluster and the fact that it is not connected to a broader regional or super-regional energy infrastructure.

The Canadian jurisdictions have not yet generated as much attention with respect to utility-of-the-future, but many are engaged in smart grid development and more targeted activities. Ontario's Smart Grid Fund, sponsored by the Ontario Minister of Energy, is a case in point, as is Alberta's Energy and Environment Solutions and Innovates - Technology Futures programs. Ontario reorganized the broader role of innovation in the Ontario Energy Board's recently adopted "Renewed Regulatory Framework for Electric Distributors" where it found:

> *The Board's incentive regulation approach to rate-setting creates incentives for distributors to innovate in order to operate within the price cap while continuing to meet the needs and expectations of their customers. The Board will further consider incentives directed at innovation to address system and customer requirements. While this work should consider the Board's current policies as set out in the Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitter and Distributors, the Board expects that new approaches may be required.*[9]

Canada's innovation model has tended to rely as much, if not more, on RD&D programs that are sponsored by national agencies. Natural Resources Canada (NRC) and Sustainable Development Technology Canada (SDTC) are both active in promoting and funding energy innovation projects. The Atlantic Canada Opportunities Agency is active on a regional basis.

While our research update does not attempt to add up the total electric and gas sector related funding for innovation, the number and scope of programs suggest these levels are increasing, in response to the drivers we mention at the outset.

SECTION 3:

SELECTED CASE STUDIES

In this update, the following case studies were selected to illustrate new programs, increases in funding for existing programs, or newly funded projects.

RD&D Programs

1. New York Renewing the Energy Vision ("REV") Demonstration Projects
2. Ofgem Network Innovation Competitions ("NICs") for Electricity
3. Ofgem Network Innovation Competitions ("NICs") for Gas
4. U.S. Department of Energy Natural Gas Modernization Initiative

RD&D Projects

1. Energy Efficient Data Centre Interconnect
2. Energy Storage Innovation for Electric Vehicles In Ontario
3. Innovative and Cost-Effective In-Line Leak Detection Tool for Gas Pipelines

RD&D Results

1. Economical Dispatch Of Combined Cooling, Heating And Power ("CCHP") Systems With Emissions Constraints, And Thermal Load Following Capability
2. Customer-led Network Revolution ("CLNR") Project

Funding mechanisms for the case studies are specific to each program. Ratepayer funding supports the programs cited for the New York Public Service Commission, Ofgem (UK), the U.S. Department of Energy (partially with the FERC levy on pipelines), the California Energy Commission and the Province of Ontario (50% born by ratepayers). Government funding also supports the programs of the DOE, Sustainable Development Technology Canada ("SDTC"), and the Province of Ontario. Third party co-funding is also utilized by Ofgem, the California Energy Commission, the Province of Ontario, and the SDTC programs.

	Funding Mechanism		
Program Sponsor	**Ratepayer Funded**	**Government Funded**	**Third Party Co-funded**
New York Public Service Commission[i]	X		X
Ofgem	X		X
U.S. Department of Energy	X	X	
California Energy Commission	X		X
Province of Ontario	X	X	X
Sustainable Development Technology Canada		X	X

[i] Third party co-funding is aspirational.

CASE STUDIES:

RECENT RD&D PROGRAMS

PROGRAM CASE STUDY 1:

NEW YORK RENEWING THE ENERGY VISION ("REV") DEMONSTRATION PROJECTS

- Sponsored by the New York Public Service Commission ("NYPSC")
- Funding – The annual revenue requirement impact of ratepayer-funded demonstration projects is capped at 0.5% of annual delivery revenues

Problem Being Addressed

The NYPSC is of the view that the success of its REV initiative depends to a significant degree on the ability of utilities to work together with third party "energy entrepreneurs" to develop new business models. Demonstration projects are expected to help inform investment decisions with respect to these new functions and test the customer responsiveness to new products and services, including pricing and delivery aspects. They may also be relied on to test the application of new technologies that appear ready to be deployed but would benefit from a demonstration project before they are implemented at scale across the utility service area. Customer engagement is a key objective and necessary in order to achieve the Commission's vision of a proliferation of customer-sited distributed energy resources.

Approach

As specified in a February 26, 2015 "Track 1" Order in the REV policy proceeding, each of the four investor-owned utilities are required to file demonstration projects by July 1, 2015 and may supplement these initial filings after that date with new proposals.[10] The Commission has specified eight criteria by which it will evaluate utility proposals:

- Demonstrating Innovation – Diversity of projects in the demonstration portfolio;
- Value Distribution – Allocation of project benefits among customers, utilities and third parties;
- Partnerships – Between utilities and third parties;
- Customer Engagement – Response to DERs across the spectrum of customers;
- Market Solutions – Enabling participants to propose solutions through competitive solicitations;
- Developing Competitive Markets – Testing rules that will further the development of new markets;
- Cyber Security – Developing data security standards and protocols; and
- Scalability – The ability to accelerate development at scale.[11]

Anticipated Value

Ideally, it is desired that these new business models will result in new and substantial transaction fee-based revenue streams for both third parties and the utilities, and thus help finance utility investments that will be required to add new functions to be performed by the utility as the Distribution System Platform ("DSP").

PROGRAM CASE STUDY 2:

NETWORK INNOVATION COMPETITIONS ("NICS") FOR ELECTRICITY[12]

- Sponsored by the UK Office of Gas and Electricity Markets ("Ofgem")
- Funding - The Electric NIC will run annually from April 2013 – March 2023 and a maximum of £27m ($50 million Canadian) will be available each year for the purposes of the competition. A further £3m will be set aside each year for the Successful Delivery Reward. Network Licensees may apply for this once they have successfully completed their Project.

Problem Being Addressed

A Network Licensee is the holder of an Electricity Transmission Licence, i.e., the National Electricity Transmission System Operator (NETSO), a Transmission Owner (TO) or an Offshore Transmission Owner (OFTO). There are also eight Distribution Network Operators (DNOs): Electricity North West; ESB Networks; Northern Ireland Electricity; Northern Powergrid; SP Energy Networks; SSE Power Distribution; UK Power Networks and Western Power Distribution.

The National Electricity Transmission System (NETS) is facing a number of challenges over the coming years. These include:

- Managing the technical challenges associated with an increasing level of intermittent generation connecting to the NETS;
- Managing the increasing impact of distributed resources and active demand on the NETS; and
- New sources of generation connecting to the network in areas far from consumption centres.

These challenges will directly affect the way transmission companies plan and manage their businesses. Network Licensees will need to innovate in the way they design, plan, and operate their networks. The Electricity NIC is designed to help stimulate this innovation and encourage Network Licensees to undertake trials to address these challenges in the most cost-effective way. Network operators will gain understanding from these trials, which they will then be able to apply to the specific challenges they face. This could potentially bring environmental benefits and cost savings to electricity customers in the future.

Approach

As part of the RIIO price controls introduced in 2012, Ofgem established a Network Innovation Stimulus. Electric transmitters were eligible beginning in 2013; distributors are eligible beginning in 2015. The innovation stimulus consists of three measures:

- A Network Innovation Competition (NIC) – An annual competition to fund selected flagship innovative Projects that could deliver low carbon and environmental benefits to customers.
- A Network Innovation Allowance (NIA) – To fund smaller innovation projects that can deliver benefits to customers as part of a RIIO-Network Licensees price control settlement. The NIA is a set annual allowance that each RIIO-Network Licensee receives to fund small-scale innovative projects as part of their price control settlement. The NIA will fund smaller scale RD&D projects and can cover all types of innovation, including commercial, technological and operational. A fixed annual regulatory allowance was established between 0.5 and 1.0 percent of allowed annual revenue for each year of the planning period.
- An Innovation Roll-out Mechanism (IRM) – To fund the roll-out of proven innovations which will contribute to the development in Great Britain (GB) of a low carbon energy sector or broader environmental benefits.

The Network Innovation Stimulus includes two annual Network Innovation Competitions (NICs), one for electricity transmission and distribution companies, and one for gas network companies. Companies compete for funding for the research, development and demonstration of new technologies, operating and commercial arrangements. Network Licensees are encouraged to collaborate with each other and “Project Partners”. Project Partners are able to contribute external funding to a project but are only eligible to lead bids for funding through a Network Licensee.

An interesting feature we see from completed projects under Ofgem innovation funding is the “close down report”. Examples are cited in Attachment A for the Low Carbon London project and the Customer-Led Revolution project. The purpose of these reports is to fully document the outcomes of projects and to share this knowledge with other utilities so they can apply new learning to their “business as usual” activities.

Anticipated Value

All electricity customers fund Electricity NIC projects. A key feature of the NIC is the requirement that learning gained through projects is disseminated in order that customers gain significant return on their funding through the broad roll-out of successful projects and the subsequent delivery of network savings and/or carbon and environmental benefits. Even where projects are deemed unsuccessful, Network Licensees will gain valuable knowledge that could result in future network savings. The project selection criteria used to screen projects suggest the anticipated benefits:

1. A NIC project must have the potential to have a direct impact on a Network Licensee’s network or on the operations of the GB System Operator and involve the development or demonstration of at least one of the following:
    a. A specific piece of new (i.e. unproven in GB) equipment (including control and/or communications systems and/or software);
    b. A specific novel arrangement or application of existing electricity transmission equipment (including control and communications systems software);
    c. A specific novel operational practice directly related to the operation of the electricity transmission system; or

d. A specific novel commercial arrangement.

In addition to meeting one or more of the requirements above, a Network Licensee must also demonstrate that their project meets all the following criteria:

2. Accelerates the development of a low carbon energy sector and/or delivers environmental benefits while having the potential to deliver net financial benefits to existing and/or future network customers;
3. Delivers value for money for electricity customers;
4. Creates knowledge that can be shared across energy networks in Great Britain or create opportunities for roll-out across a significant proportion of Great Britain networks;
5. Is innovative (i.e., not business as usual) and has an unproven business case where the innovation risk warrants a limited development or demonstration project to demonstrate its effectiveness.

Status

On 9 August 2013, Network Licensees submitted three projects to be considered for funding through the Electricity NIC. Ofgem selected two of these projects for funding:

Project Awarded Funding	Network Licensee	Funding Awarded
Multi Terminal Test Environment for HVDC Systems	Scottish Hydro Electric Transmission Limited	£11.3m
Visualization of Real Time System Dynamics using Enhanced Monitoring	SP Transmission Limited	£6.5m

On 25 July 2014, electricity Transmission Licensees submitted four projects to be considered for funding through the Electricity NIC. Ofgem selected three of these projects for funding.

Project Awarded Funding	Network Licensee	Funding Awarded
Enhanced Frequency Control Capability	National Grid Electricity Transmission Plc	£6.9m
Modular Approach to Substation Construction	Scottish Hydro Electric Transmission Limited	£2.8m
Offshore Cable Repair Vessel and Universal Joint	TC Ormonde OFTO Limited	£9.0m

PROGRAM CASE STUDY 3:

NETWORK INNOVATION COMPETITIONS ("NICS") FOR GAS[13]

- Sponsored by the UK Office of Gas and Electricity Markets ("Ofgem")
- Funding – The Gas NIC will run annually from April 2013 – March 2021 and a maximum of £18m ($33.3 million Canadian) will be available each year for the purposes of the competition. A further £2m will be set aside each year as an incentive reward to successful projects.

Problem Being Addressed

There are four gas distribution companies operating in Britain: National Grid Gas (NGG), Scotia Gas Network (SGN), Northern Gas Networks (NGN) and Wales & West Utilities (WWU). National Grid is the sole owner of the gas transmission network in the UK. UK's gas transmission and distribution companies face a number of challenges over the coming years.

These include:

- Playing a role in delivering the low carbon economy and the objectives of the UK Carbon Plan
- Reducing the overall carbon footprint of the gas transportation businesses
- Enabling alternative and/or renewable sources of gas to connect to the network.
- Adapting the networks to cope with the impact of climate change

These challenges will affect the gas distribution and transmission networks and the way the Network Licensees plan and manage their businesses. Network Licensees will need to innovate in the way they design, plan, build and operate their networks.

Approach

As part of the RIIO price controls introduced in 2012, Ofgem established a Network Innovation Stimulus. The innovation stimulus consists of three measures:

- A Network Innovation Competition (NIC) – An annual competition to fund selected flagship innovative projects that could deliver low carbon and environmental benefits to customers.
- A Network Innovation Allowance (NIA) – To fund smaller innovation projects that can deliver benefits to customers as part of a RIIO-Network Licensees price control settlement. The NIA is a set annual allowance that each RIIO-Network Licensee receives to fund small-scale innovative projects as part of their price control settlement. The NIA will fund smaller scale RD&D projects and can cover all types of innovation, including commercial, technological and operational. The NIA is a set annual allowance that allows Network Licensees a funding opportunity of 0.7% of revenue to be spent on innovation projects, 90% of which can be recovered through the incentive mechanism.
- An Innovation Roll-out Mechanism (IRM) – To fund the roll-out of proven innovations which will contribute to the development in Great Britain (GB) of a low carbon energy sector or broader environmental benefits.

As with the electric program, under the Network Innovation Competitions (NICs) companies compete for funding for the research, development and demonstration of new technologies, operating and commercial arrangements. The Gas NIC is designed to encourage Network Licensees to undertake trials to address these challenges in the most cost-effective way. Network Licensees will gain understanding from these trials, which they will then be able to apply to the specific challenges they face. This could potentially bring benefits and cost savings to consumers in the future.

Network Licensees are encouraged to collaborate with each other and project partners. Project partners are able to contribute external funding to a project but are only eligible to lead bids for funding through a Network Licensee.

Anticipated Value

Customers of the gas network fund the Gas NIC projects. Therefore, a key feature of the NIC is the requirement that learning gained through projects is disseminated. This is to ensure that customers gain significant return on their funding through the broad rollout of the funded projects. This return includes the delivery of network savings and/or carbon and environmental benefits. Even where the funded projects are deemed unsuccessful at the end of the project life, Network Licensees will gain valuable knowledge that could result in future savings. The project selection criteria used to screen projects suggest the anticipated benefits:

1. A NIC project must have the potential to have a direct impact on a Network Licensee's network or the operations of a GB System Operator and involve the development or demonstration of at least one of the following:
    a. A specific piece of new (i.e. unproven in GB) equipment (including control and communication systems and/or software);
    b. A specific novel arrangement or application of existing gas transmission and/or distribution equipment (including control and communication systems software);
    c. A specific novel operational practice directly related to the operation of the gas transportation system; or
    d. A specific novel commercial arrangement.

In addition to meeting one or more of the proceeding requirements, a Network Licensee must also demonstrate that the project meets the following ISP criteria:

2. Accelerates the development of a low carbon energy sector and/or delivers environmental benefits while having the potential to deliver net financial benefits to existing and/or future network customers;
3. Delivers value for money for gas customers;
4. Creates knowledge that can be shared across energy networks in Great Britain or create opportunities for roll-out across a significant proportion of GB networks;
5. Is innovative (i.e. not business as usual) and has an unproven business case where the innovation risk warrants a limited development or demonstration project to demonstrate its effectiveness.

Status

In the first year of the competition, six submissions requested funding for a total of £26.31m. From these, four projects were selected for funding by an expert panel, for £15.12m, of the available £18m. This funding will be recovered in rates beginning with the April, 2014 rate year. In addition to the NIC funding, the Network Licensees and a range of partners will invest an additional £4.72m in funding.

Project (Location)	Funding Awarded
BioSNG Demonstration Plant (Swindon) A project to construct a demonstration plant investigating the techno-economic feasibility of the thermal gasification of waste to produce pipeline quality renewable gas. **Submitted by National Grid Gas Distribution**	£1.8m
Low Carbon Gas Preheating (North East) A project to test new and emerging pre-heating technologies and associated operating systems. **Submitted by Northern Gas Networks**	£4.8m
Opening up the Gas Market (Oban) A project to establish whether gas which sits outside the British standards could be used safely and efficiently. **Submitted by Scotland Gas Networks (SGN)**	£1.8m
Robotics (South East) A project to develop new robotic technologies that operate inside live gas networks, in order to repair leaking joints, manage the risk of pipe fracture in larger diameter pipes, and repair and replace pipeline assets. **Submitted by Southern Gas Networks**	£6.5m

In the second year of funding, eligible Network Licensees submitted two projects in July 2014 to be considered for funding through the NIC. In this year's decision Ofgem selected one of these projects for funding.

Project Awarded Funding	Network Licensee	Funding Awarded
In Line Robotic Inspection of High-Pressure Installations	National Grid Gas Transmission	£5.6m

PROGRAM CASE STUDY 4:
NATURAL GAS MODERNIZATION INITIATIVE[14]

- Sponsored by the U.S. Department of Energy ("DOE")
- Funding - Initial funding includes $15m for the DOE to develop and demonstrate more cost-effective technologies to detect losses from natural gas transmission and distribution systems. An additional $10m is proposed to quantify emissions from natural gas infrastructure in coordination with the Environmental Protection Agency. DOE will also work with the Federal Energy Regulatory Commission (FERC) to develop regulatory incentives for natural gas infrastructure modernization investments.

Problem Being Addressed

Methane emissions accounted for nearly 10 percent of U.S. greenhouse gas emissions in 2012, of which nearly 30 percent came from the production, transmission and distribution of oil and natural gas. U.S. oil production is at the highest level in nearly 30 years, and the U.S. is also now the largest natural gas producer in the world. Emissions from the oil and gas sector are down 16 percent since 1990. However, emissions from the oil and gas sector are projected to rise more than 25 percent by 2025 without additional steps to lower them. The Obama Administration is committed to taking responsible steps to address climate change, and as part of that effort, announced a new goal to cut methane emissions from the oil and gas sector by 40 – 45 percent from 2012 levels by 2025, and a set of actions to put the U.S. on a path to achieve this ambitious goal.

Approach

The Administration announced on January 14, 2015 it is undertaking a series of steps encompassing standards and cooperative engagement with states, tribes and industry toward meeting the 2025 goal. This cross-agency effort envisions a harmonized approach that considers the roles of FERC, state utility commissions and environmental agencies, and industry. Administration actions include:

- Propose and set common sense standards for methane and ozone-forming emissions from new and modified sources
- New guidelines to reduce volatile organic compounds
- Consider enhancing leak detection and emissions reporting
- Lead by example on public lands
- Reduce methane emissions while improving pipeline safety
- Drive technology to reduce natural gas losses and improve emissions quantification
- Release a Quadrennial Energy Review (QER)

There is one initiative that is directly applicable to the utilities sector:

- Modernize Natural Gas Transmission and Distribution Infrastructure, whereby DOE will continue to take steps to encourage reduced emissions, particularly from natural gas transmission and distribution, including:

- Issuing energy efficiency standards for natural gas and air compressors;
- Advancing research and development to bring down the cost of detecting leaks;
- Working with FERC to modernize natural gas infrastructure; and
- Partnering with NARUC and local distribution companies to accelerate pipeline repair and replacement at the local level.

Anticipated Value

A strategy for cutting methane emissions from the oil and gas sector is an important component of efforts to address climate change. Reducing methane emissions means capturing valuable fuel that is otherwise wasted while reducing harmful pollutants. Achieving the Administration's goal would save up to 180 billion cubic feet of natural gas in 2025, enough to heat more than 2 million homes for a year and support businesses that manufacture and sell cost-effective technologies to identify, quantify, and reduce methane emissions.

Status

The Initiative builds on prior policies designed to reduce methane emissions. One dimension of the Initiative has progressed at FERC:

- In November 2014 FERC issued a proposed policy statement and sought comments regarding potential mechanisms for interstate natural gas pipelines to recover the costs of modernizing their facilities and infrastructure to enhance the efficient and safe operations of their systems. The Commission issued the policy statement in an effort to address these costs and to ensure that existing Commission ratemaking policies do not unnecessarily inhibit interstate natural gas pipelines' ability to expedite needed or required upgrades and improvements, such as replacing old and inefficient compressors and leak-prone pipelines. After review of the comments on the proposed policy statement, the Commission on April 16, 2015 established a policy allowing interstate natural gas pipelines to recover certain capital expenditures made to modernize system infrastructure through a surcharge mechanism, subject to conditions intended to ensure that the resulting rates are just and reasonable and protect natural gas consumers from excessive costs.[15]

CASE STUDIES:
RECENT RD&D PROJECTS

PROJECT CASE STUDY 1:
ENERGY EFFICIENT DATA CENTRE INTERCONNECT

Sponsored by:

- Sustainable Development Technology Canada (SDTC)
- National Resource Council of Canada
- Ranovus, Inc.
- Funding – $4.25 million from SDTC – out of a total project value of $14.3 million

Problem Being Addressed

When users post photos or update statuses on major social networks, or when they use the cloud to back up their data, they create digital traffic within data centres around the world. The energy required for data centres is huge — accounting for two percent of the world's electricity consumption and 1.5 percent of the global carbon footprint — and it continues to grow at a rapid rate. Today, there are no power-efficient, cost-effective and scalable solutions to support impending future bandwidth requirements.

Approach

Ranovus brings together technologies, including a state-of-the-art quantum dot laser and silicon photonics, to streamline the way data flows through a data centre. The resulting 100 Gb/s transceiver module can be integrated into a data centre, reducing its cost of doing business eight-fold and its power consumption four-fold.

Anticipated Value

Power-efficient, cost-effective and scalable solutions to support impending future bandwidth requirements.

PROJECT CASE STUDY 2:
ENERGY STORAGE INNOVATION FOR ELECTRIC VEHICLES IN ONTARIO[16]

Sponsored by:

- Ontario's Smart Grid Fund
- Ontario Ministry of Energy
- Funding - In the second round of funding in 2014, 17 projects were awarded a total of CA$23.7 million (US$20.8 million) across a range of projects for energy storage, microgrids, behind the meter, grid automation and data analytics. The province's funding will be matched by $54 million in funding from the energy sector. Ontario's initial $14.1 million resulted in more than $100 million in private investment.

Problem Being Addressed

The arrival of electric vehicles is bringing new challenges to utilities in managing their impact on the grid. Ryerson University's Centre for Urban Energy plans to demonstrate a pole-mounted energy storage system to facilitate EV integration and improve grid stability and reliability on Toronto Hydro's network.

Approach

In the project, a modular storage solution from the local storage company eCamion will be combined with a smart controller, developed by Ryerson, which communicates with downstream smart meters of connected residences. The objective is to develop and demonstrate the solution to show the integration of smart meters, electric vehicle chargers and improved system reliability.

Anticipated Value

The project is regarded as an important demonstration of the promise of storage at the edge of the grid. Toronto Hydro, as the local utility, should benefit by way of reduced cost of infrastructure upgrade, reduced energy costs, reduced usage during peak hours, enhanced grid reliability and increased power flexibility. In addition, the project will showcase eCamion's technology, which is going to be pursued for worldwide commercialization.

PROJECT CASE STUDY 3:

INNOVATIVE AND COST-EFFECTIVE IN-LINE LEAK DETECTION TOOL FOR GAS PIPELINES

Sponsored by:

- Sustainable Development Technology Canada (SDTC)
- Pure Technologies Alliance Pipeline Ltd.
- Plains Midstream Canada
- City of Calgary
- Funding - $1 million from SDTC – out of a total project value of $3 million

Problem Being Addressed

Identifies suspected small gas pipeline leaks before they can grow and create ruptures.

Approach

Tests the ability to transfer a "SmartBall" technology that is already used for water and oil pipelines to the natural gas industry. The SmartBall relies on acoustic leak detection at a high resolution that identifies leaks and their location and communicates back to the operator.

Anticipated Value

Faster leak detection and location reported back to the pipeline operator, avoiding leaks and associated release of methane.

CASE STUDIES:

RECENT RD&D RESULTS

RESULTS CASE STUDY 1:

ECONOMICAL DISPATCH OF COMBINED COOLING, HEATING AND POWER ("CCHP") SYSTEMS WITH EMISSIONS CONSTRAINTS AND THERMAL LOAD FOLLOWING CAPABILITY[17]

- Sponsored by the California Energy Commission (Final Project Report issued July 2014)
- Funding – Modest cost (about $400,000), since the project heavily leverages previous investment and uses significant previously developed expertise and resources

Problem Being Addressed

Most commercial and industrial electrical loads are highly dynamic and typically not synchronized with local heating and cooling demands. These dynamics, together with utility tariff and rate structures, often make CCHP systems less cost-effective and less attractive to end users. There are advancements being made in smaller CCHP technologies, but several regulatory, market, and technology barriers remain. These include continuing improvement in the cost of smaller CCHP equipment, awareness of the CCHP options among commercial and small industrial customers, and environmental and zoning issues. This particular study focuses on the fact that the cooling and heating or "thermal" load profile for many customers does not follow the electricity load. The economics of CCHP will be improved through the use of algorithms that optimize the dispatch of the CCHP equipment reflecting thermal loads, electricity loads, and any environmental constraints. Electric utility tariff designs including the ability to sell excess power to the grid or take advantage of demand response programs also contribute to the economics. Lower delivered gas prices also improve the economics.

Approach

The project simulated the thermal and electrical load profiles of several commercial and industrial customers and tested the economic impact different economic control and dispatch strategies based on gas and electric utility tariff structures. Using these control strategies applied to a Capstone C65 microturbine generator, building types, and utility rate models, the project examined various generator characteristics.

Anticipated Value

CCHP technology results in significant energy efficiency improvements and associated lower customer costs while also producing meaningful reductions in greenhouse gas emissions. It will help address the barriers to smaller CCHP applications that is an underserved market that has great potential as a source of electric capacity if barriers can be addressed. The project sponsors estimated that the potential contribution to capacity in the United states was approximately 100 GW.

Results

The project developed control algorithms that would optimize the CCHP dispatch given economic objectives and environmental emissions constraints. The models were subjected to dynamic CCHP load demands and other sources of variation.

RESULTS CASE STUDY 2:

CUSTOMER-LED NETWORK REVOLUTION (CLNR) PROJECT

- Sponsored by Northern Powergrid Northeast
- Funding – The project investment of £31 million is funded by the Low Carbon Networks Fund (approximately 90%) and a mandatory contribution by Northern Powergrid Northeast (approximately 10%). Supplemental funding is also contributed by third-party participants in the project, including customer contributions.

Problem Being Addressed

The transition to a "low carbon economy" will be challenging from a:

(1) technological perspective (connecting and integrating new distributed energy resources to a grid that was not designed with this in mind while monitoring and controlling the impact on the reliability of the network),

(2) customer engagement perspective (required to attract participation) and

(3) financial perspective (maintaining the affordability of energy and related services).

The CLNR is a comprehensive demonstration project that tests technological and customer engagement approaches with the goal of identifying efficient and affordable paths forward to transition to the low carbon economy. The project set out to determine whether customers could be flexible in the ways they use and generate electricity and how distributors can support the reduction in customer energy costs and the carbon footprint.

Approach

The CLNR project was a four-year effort to test a broad range of "utility-of-the-future" concepts in an integrated manner involving approximately 13,000 customers and distributed generators and obtain learning from the efforts. The project required significant efforts to engage a broad cross-section of customers by customer class, size and income levels and attract their active participation with distributed resources, innovative tariffs and load response, with appropriate customer protections related to marketing and data privacy. It explored new commercial arrangements among third-party suppliers, distributors, and customers. The project involved the significant investments in equipment including customer and grid storage technologies, customer "smart energy systems", load controllable end-user appliances, and several network technologies including monitoring equipment, voltage control, and other control technologies. Significant compensation was provided to three contractors: British Gas (energy retailer partner), EA Technology Limited (network competencies), and Durham and Newcastle Universities (data analyses). As noted above, external funding was also provided by third parties and customer contributions for installation of certain customer equipment (solar PV, heat pumps, smart meters, and electric vehicle charging points).

Results

The project produced extensive learning across a range of outcomes including estimation of load and generation profiles to assist with system planning, measurement of the value of a more flexible network and customer load flexibility, and testing of network control solutions either to address network constraints or to operate the solutions (once installed) on a real-time basis.

Anticipated Value

Northern Powergrid Northeast estimated the value of learning at upwards of £5 billion from implementation at scale derived from four categories: capital cost savings to enhance the network, customer benefits, reduced carbon emissions, and generation capital cost savings from lower peak demands.

SECTION 4:
CONCLUSIONS

The emphasis on innovation in the electric and natural gas industries has increased over the past year as the industry seeks to leverage advances in information and communications technologies, distributed energy resource technologies, and other technologies that allow utilities to perform their responsibilities more efficiently. A second major trend is the push by regulators for changes in the business model and role of the utility that requires a much greater understanding about how third parties and utilities can work together to deliver new products and services and about what it will take to engage customers in these opportunities. In both cases, there is a critical role for regulators to serve to fund utility innovation through customer rates while ensuring these investments satisfy the public interest. Ratepayer-funded projects serve as an important resource, in addition to investment by government, industry and third-party sources. Customers are the ultimate beneficiaries of these innovation projects and, in many cases, they would not be performed by unregulated market participants.

Many of the public and ratepayer-funded programs we cite remain in their formative stages, so results from these efforts remain more anticipated than demonstrated. Innovation by its nature is riskier than business as usual, so not all projects will be successful. Nonetheless, it will be important for policymakers, regulators and utilities to demonstrate tangible consumer benefits as these programs mature, even if substantial portions of these benefits spill over into the broader public domain.

An update to our research on utility related innovation programs from which the case studies have been selected is provided in Attachment A.

ATTACHMENT A:

SURVEY OF INNOVATION EFFORTS

The following table summarizes Concentric's research into new programs, expansion of existing programs or selected projects identified since our 2014 report.

NEW GOVERNMENT AND REGULATORY AGENCY PROGRAMS

Location	Program	Purpose	Status
Department of Energy (EERE-AMO Office)	Natural Gas Modernization Initiative	Launch a collaborative effort with industry to evaluate and scope high impact manufacturing R&D to improve natural gas system efficiency and reduce leaks with the goal of establishing an advanced manufacturing initiative.	DOE plans to hold a technical workshop to identify the most pressing opportunities in the natural gas system and to focus the technical community on the development of relevant solutions to these challenges.
European Commission	LIFE Programme: Private Finance for Energy Efficiency (PF4EE)	Aims to increase private financing for investments in energy efficiency enhancing projects. Its objective is to support member states in making progress in view of the EU's agreed targets for energy efficiency.	The European Investment Bank is currently accepting proposals and will approve 10-15 from diverse member states.
Hawaii	JumpSmart Maui program, a collaboration between New Energy and Industrial Technology Development Organization (NEDO) – a Japanese organization – and Hawaii	Incorporate smart grid, renewable energy and electric vehicle solutions on Maui, funded through a $30 million investment by NEDO. The project will also enable Maui to become more energy efficient, create a more stable energy infrastructure to help lower residential energy bills, and attract high-tech projects to generate job growth.	Since its inception in 2011, Hitachi's JumpSmart Maui initiative, Haleakala Solar, has completed the installation of residential charging stations and is under contract to construct a number of new charging station projects in 2015.
Massachusetts	RD&D funding as part of Utility Grid Modernization Filings	RD&D efforts to focus on testing, piloting and deployment of new and emerging technologies to meet grid modernization objectives.	Proposed RD&D projects to be included in Grid Modernization filings for the three investor-owned electric utilities required by August 1st, including a proposed funding mechanism.

Location	Program	Purpose	Status
New York	Advanced Grid Innovation Laboratory for Energy (AGILe)	Build a facility devoted to energy technology innovation and the rapid deployment of smart-grid technology to modernize New York's electric grid. The research will aid utilities in making their transmission and generation operations more efficient and to help integrate renewable energy resources into the power grid.	Project announced in late March 2015.
New York	Demonstration projects to support Renewing the Energy Vision ("REV") business model transformation policy initiative	Prepare the utilities to serve as the Distributed System Platform ("DSP"), test new business models, and inform the Commission and stakeholders concerning how best to engage customers to consider DERs and new products and services that will be enabled by REV.	Utility-proposed demonstration project filings due by July 1, 2015.
New York	NYSERDA – "NY Prize"	$40 million energy competition aimed at spurring new business models and partnerships to modernize the state's electric grid.	Currently seeking proposals from communities to study the feasibility of microgrids. NYSERDA will accept 25-30 communities for the next phase of the project.
UK (Ofgem)	Network Innovation Competitions ("NICs") for Electricity	Competition amongst electricity transmission and distribution companies for innovation stimulus funding to support the R&D and demonstration of new technologies, operating and commercial arrangements.	NICs for electricity completed its second round of funding in July 2014, selecting three of the four proposals submitted
UK (Ofgem)	Network Innovation Competitions ("NICs") for Gas	Competition amongst gas network companies for innovation stimulus to fund the R&D and demonstration of new technologies, operating and commercial arrangements.	NICs for gas completed its second year in July 2014, selecting one of two projects considered for funding.

NEW RD&D PROJECTS

Jurisdiction (Sponsor)	Project	Description	Objectives
Alberta	In-Line Leak Detection Tool for Gas Pipelines	Acoustic line detection tool.	Provide quick detection and location of small leaks.
British Columbia	Rechargeable Zinc Air Fuel Cell	Testing of fuel cell made from abundant resources (zinc and air).	Potential microgrid energy storage technology.
California (PG&E)	PG&E 3D Toolbox	Develop "smart pigs" to assess the condition of natural gas pipelines for dents, cracks and corrosion on the outside of gas pipelines.	Give PG&E real-time information about the condition of pipeline surfaces and speed up the assessment process.
California (PG&E)	PG&E Innovative Leak Detection Technology	Under a pilot program, the leak detection tool mobilizes large numbers of PG&E gas workers concentrating on repairs in a specific area.	Finds and repairs natural gas leaks faster and more efficiently.
Canada	Innovative and Cost-Effective In-Line Leak Detection Tool for Gas Pipelines	Tests the ability to transfer “SmartBall” technology, already used for water and oil pipelines, to the natural gas industry.	Avoids leaks and associated methane release through faster leak detection technology.
Department of Energy (DOE)	Consortium for the Advanced Simulation of Light Water Reactors (CASL)	Renewed funding for the energy innovation hub that develops advanced computing capabilities to serve as a virtual version of existing, operating nuclear reactors.	Enable the role of nuclear energy and advance research in a dependable, low-carbon energy source.
DOE Fuel Cell Technologies Office (FCTO)	Gas Technology Institute	Assess the technical and economic feasibility of thermal compression for cost-effective pressurization of hydrogen to 700 bars for hydrogen fueling stations.	To support innovations in fuel cell and hydrogen fuel technologies.
Ontario	Energy Efficient Data Centre	Application of Quantom Dot Laser and Silicon Photonics to streamline data flows.	Reduce cost and energy usage of data centres.
Ontario	EV Technology Interoperability	Integrate the building energy management system, EV applications, advanced energy storage, solar generated energy and a distribution automation applications	Assess the impact of storage between a grid infrastructure and commercial customer valuation perspective.

Jurisdiction (Sponsor)	Project	Description	Objectives
		network to expand opportunities for customer control, enable conservation and allow for high penetrations of renewable generation.	
Ontario	Gallium Nitride Power Devices for High-Efficiency Industrial Battery Chargers	Testing of charging efficiency of lower weight electric vehicle batteries.	Reduce power losses and generation of waste heat during the charging process.
Ontario	Ryerson University's Centre for Urban Energy's Pole-mounted Storage	Modular storage solution will be combined with a smart controller, which communicates with downstream smart meters of connected residences.	Develop and demonstrate a pole-mounted energy storage system to facilitate EV integration and improve grid stability and reliability on Toronto Hydro's network.
Ontario	Storage for EV Charging Station Management (Toronto Hydro)	Install energy storage systems to solve issues caused by the sudden connect/disconnect of EVs and system congestion.	Demonstrate how its system can mitigate issues including peak management, peak charging management, infrastructure deferment, harmonics and voltage and frequency regulation.
Québec	SIMLOC: Fault Locating on Underground Distribution Lines	Hydro-Québec developed a system for locating damage along underground lines and at cable joints.	Shortens and standardizes the time it takes to locate a fault as well as reduces the risk of damaging the cables or other equipment.

RESULTS OF RECENT INNOVATION PROJECTS

Jurisdiction (Sponsor)	Project	Description	Results
California (CEC)	Dispatch of Load Following Small-Sized CHP Subject to Economic and Environmental Costs	Test ability to address market barriers to small-scale CHP.	Developed and tested new control algorithms
California (CEC)	Solid State Batteries for Grid-Scale Energy Storage	Demonstration of Lithium Batteries up to 10 kWh.	Validated process for producing grid-scale batteries. Tested 10 kWh battery pack.
Ofgem (UK)	Low Carbon London	Evaluate impact of low carbon technologies on London's electricity distribution network.	Achieved significant cost-sharing benefits of approximately £14m with customers and met all of its reward criteria. Led directly to the reduction of capital investment plans by £43m.
Ofgem (UK)	Customer-Led Network Revolution	Trial customer and network flexibility techniques to deliver greater capacity at a lower cost.	Produced insights and knowledge with net benefits estimated in the range £5b to £26b from 2020 to 2050.

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Annexe D

I. INTRODUCTION

Q. Please state your name, business address and present position for the record.

A. My name is Robert C. Yardley, Jr.; my business address is 107 South Street, 3A Boston MA 02111. I am the founder of Waterstone Group, which provides advisory services to public and private energy organizations with particular expertise in regulatory policies that pertain to the transition to competitive wholesale and retail energy markets.

Q. Please describe your educational and professional background.

A. A statement of my education and experience is attached to my testimony as Attachment 1. As indicated in this attachment, I have worked in the energy industry for my entire 20-year professional career. For two of those years (1991-92), I served as Chairman of the Massachusetts Department of Telecommunications and Energy (which was named the Department of Public Utilities at that time).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Southern Gas Company's ("Southern's" or "the Company's") proposal to implement an alternative rate or performance-based ratemaking ("PBR") plan. I have been working as an advisor to Southern since January of this year to develop a PBR proposal. Specifically, I was asked by the Company to help them develop a proposal that would provide tangible benefits to Southern's customers, advance the policy objectives of the Commission, and provide Southern with incentives to operate efficiently and grow while preserving the Company's quality of service. I believe that Southern's PBR proposal accomplishes these objectives in a manner that provides an appropriate balance between the interests of Southern and its customers.

My testimony will provide an overview of the plan, the details of the rate aspects of the plan, and the reasoning relied upon to develop the plan. I will also provide an overview of the Service Quality Plan ("SQP"), which is a key component of Southern's proposal. In so doing, I will describe the importance of a SQP as an element of a PBR proposal and the process that Southern used to develop the specific service quality measures.

Q. Are any other witnesses providing testimony that addresses Southern's PBR proposal?

A. Yes. Mr. Sal Ardigliano and Mr. Peter Loomis present testimony which describes the SQP in much greater detail, including a discussion of each of the specific measures that are being proposed by Southern. These individuals have responsibility for the operational areas of the Company that provide the customer services that the SQP will measure.

Q. How is Southern's PBR proposal related to its proposal in this application to increase its rates and charges?

A. Southern is filing a traditional rate case in this application to address a revenue deficiency. The rates established in the rate case portion of this proceeding will serve as the "cast-off" rates for purposes of implementing the PBR plan.

There is one important distinction, however. As indicated in the Application, Southern reserves the right to decline to implement the PBR plan should the likely revenue path established by the Commission order prove to be untenable. This option is made necessary by Southern's agreement to relinquish its right to file a rate case during the term of the plan. It is certainly Southern's intention to avoid this result and the PBR proposal has been developed with that objective in mind.

Q. What will happen if Southern declines to implement the PBR plan?

A. If Southern declines to implement the PBR plan, the current regulatory rate setting practices would continue to apply. Thus, Southern would be subject to an excess earnings review if its earned return on equity exceeded its allowed return on equity by greater than 100 basis points for six consecutive months. The

Commission would also require Southern to file for a Financial Review after four years if Southern had not filed a rate case in the interim. Thus, the PBR plan is truly intended and perhaps best considered as an "alternative" approach to rate setting over the next four years for the Commission to consider.

Q. How is your testimony organized?

A. In the following section, I will present a summary of Southern's proposal and my proposed findings. That will be followed by a discussion in Section III of background information that Southern considered in developing its proposal, including relevant precedent in the State of Connecticut. The details of Southern's proposal are described in Section IV. A summary of the merits of the proposal is presented in the final section of my testimony.

II. SUMMARY OF SOUTHERN'S PBR PROPOSAL

Q. Please provide a summary of Southern's proposal.

A. Southern is proposing to freeze its base rates for the next four years at the levels to be established in this proceeding, with the following caveat: if the Commission agrees that an acceleration of Southern's bare steel services and cast iron mains replacement program is desirable, Southern will increase its expenditures in this area by as much as $3 million per year over and above the $5 million of annual expenditures that are reflected in the current capital plan. This option would have a modest impact on customer rates.

Southern is also proposing to implement an Earnings Sharing Mechanism ("ESM") with 50-50 sharing of any earnings that exceed Southern's allowed return on equity outside of a 100 basis point collar or deadband. Sharing with customers will occur on the upside only; Southern proposes that its shareholders absorb any earnings shortfall on the downside.

In order to demonstrate an ongoing commitment to service quality, Southern is proposing to implement a Service Quality Plan ("SQP") as an integral part of the PBR proposal. Under the SQP, Southern will submit periodic information to the Commission regarding its service quality based on five separate measures. Southern is not proposing to institute any financial rewards or penalties as part of its SQP.

Finally, as is common in PBR proposals, Southern is proposing a limited set of rate relief conditions under which rates would either be adjusted (to reflect the impact of a limited set of pre-specified "exogenous" events) or reopened (to address any serious deterioration in Southern's financial condition).

Q. How does the proposal provide tangible benefits to Southern's customers?

A. The proposal provides rate stability and certainty to Southern's customers over a four-year period, while providing an opportunity to share significantly if Southern is able to increase its earnings as a result of operating more efficiently or successfully competing to attract new load. Second, the SQP provides the Commission with an assurance that Southern's commitment to providing service of the highest quality will continue and provides the Commission with a formal mechanism to track its performance in this area. Third, the bare steel/cast iron replacement option, if implemented, will improve the safety and reliability of Southern's distribution system.

Q. Does the Commission have the statutory authority to approve Southern's proposal?

A. Yes. It is my understanding, based on a review of Connecticut General Statute Section 16-19kk(c) and consultation with Southern's legal staff that the Commission has the authority to approve Southern's proposed alternative rate plan.

Q. Please summarize the findings that you propose be adopted by the Commission.

A. I propose that the Commission find that:

(1) it has the statutory authority to approve a PBR plan for a natural gas distribution company;

(2) Southern's proposal will provide tangible benefits to customers and is in the public interest;

(3) Southern's PBR plan be approved as proposed by Southern without modification;

(4) Southern's rates over the term of the PBR plan will conform to the principles and guidelines set forth in Connecticut General Statute, Section 16-19e; and

(5) The plan for periodic review of the PBR shall be in lieu of the requirements of Connecticut General Statute, Section 16-19a(a) as permitted by Section 16-19a(b).

III. BACKGROUND ON PBR AND CONNECTICUT PRECEDENT

Q. Has the Connecticut DPUC approved PBR plans for other utilities?

A. Yes. United Illuminating Company ("UI") and Southern New England Telephone Company ("SNET") are currently operating under multi-year PBR rate plans. While the circumstances faced by these utilities are distinct from those facing Southern, the Commission's orders in these cases provided useful guidance to Southern in developing its own proposal.

The UI precedent is the most relevant of the two cases. This is due in part to the fact that both the electric and natural gas distribution industries are in the early stages of a transition toward retail competition. UI's proposal is also responsive to its need to dispose of its generation assets and the potential for stranded costs associated with its nuclear generation facilities, a circumstance that is not shared by Southern. However, the UI precedent did provide the Commission's perspective on the importance of providing tangible benefits to customers and the role of service quality monitoring during the term of the plan. Most importantly, it indicated that the Commission is willing to consider and approve an alternative approach to rate setting that recognizes the potential for customers and shareholders to benefit from improved operating efficiencies.

The SNET precedent has much less direct relevance because of the fact that the industries are radically different, particularly with respect to the role that emerging technologies play in the telecommunications industry. However, the SNET experience did provide some guidance in developing Southern's SQP.

Q. Have other natural gas distribution utilities in this region implemented PBR plans?

A. Yes. Within the last few years, PBR plans have been approved for Boston Gas Company, Bay State Gas Company and Providence Gas Company. Additionally, many of the New York distribution companies have been operating under multi-year rate settlement agreements which operate in many respects as PBR plans.

Each utility's PBR proposal reflects its unique set of financial and operating circumstances as well as policy guidance that has been provided by its state regulatory agency. Nonetheless, these plans are informative because they provide a sense of how rate and service quality issues have been addressed by other utilities and their regulatory commissions.

Q. Why have state regulatory commissions and utilities expressed an interest in PBR in recent years?

A. I believe that there are two primary and closely-related factors that are driving the interest in PBR and multi-year rate agreements. First, there has been an interest over the past decade in improving the incentives that utilities have to lower costs and thereby lower customer bills. In New England, this interest began as the region slowly emerged from the economic slowdown at the end of the 1980s and has not abated. While the traditional rate case approach served regulators well for many years, there was a growing interest in trying “incentive-based” approaches. At first, many of the incentive programs were developed to provide utilities with an incentive to invest in conservation and load management programs or to operate their generating facilities more efficiently. However, as rate pressures grew, commissions and utilities began to focus on broader incentives.

The second and related factor is the introduction of retail competition. With the introduction of retail competition, utilities recognize the need to be more competitive. Lower rates and higher quality service each contribute to this objective. In addition, as a result of legislative and regulatory policies, there is a much finer distinction between activities that will continue to be regulated and those that will be provided by utilities and other firms in a competitive environment. The restructuring effort frequently includes provisions that encourage regulatory agencies to consider PBR for those activities that continue to be regulated.

There is also a recognition by both utilities and regulatory agencies that the introduction of retail competition requires an enormous amount of work on both policy development and business process redesign and implementation. Time and resources devoted to litigation of traditional rate cases and earnings reviews might be more productively spent on the challenge of ensuring that customers will benefit from retail competition.

Q. Is PBR a radical departure from the traditional regulatory rate setting practices?

A. PBR is not really a radical departure from traditional regulatory rate setting practices. In particular, the goals of regulation have not changed dramatically. However, PBR does represent an alternative means of pursuing those goals and can result in greater efficiency and lower rates to customers.

IV. DETAILED REVIEW OF SOUTHERN'S PBR PROPOSAL

Rate Plan and Term

Q. How will customer rates be set during the term of the PBR plan?

A. Southern is proposing to freeze its base rates through December 31, 2003 (or approximately four years depending on the effective date of the rates established in this proceeding). Rates will be frozen at the levels to be established in this proceeding. Southern is also proposing to accelerate its cast iron main/bare steel service replacement program as an option for the Commission to consider. This option, which will be described later in my testimony, would have a modest impact on rates.

Q. Why is Southern proposing a four-year term for the plan?

A. A four-year term reflects a balance between Southern's desire to provide its customers with the benefits of an extended rate freeze and the considerable operating uncertainties that Southern and other distribution companies will face over the next four years. These uncertainties are primarily attributable to the changes in the industry brought about by the transition to a competitive retail market. Southern's proposal has been structured to insulate Southern's customers from these risks. In particular, under Southern's proposed ESM structure, Southern's shareholders absorb all of the downside earnings risk while providing customers with the ability to share in upside earnings. The risk associated with Southern's rate freeze and ESM commitments increases as the term of the PBR plan increases.

Earnings Sharing Mechanism

Q. Why is Southern proposing an Earnings-Sharing Mechanism?

A. ESMs are frequently included as part of PBR plans because they provide an automatic mechanism for customers to share in benefits that result from the types of activities that the PBR plan is intended to encourage. In Southern's case, the mechanism as proposed is assymetrical; that is, it provides customers with the ability to share in cost savings or revenue increases that contribute to an increase in earnings, while insulating them from the impact of a deterioration in earnings during the term of the rate plan. Southern believes that this is a much more efficient regulatory approach as it encourages efficient behavior and is also more administratively efficient than the current regulatory approach.

Q. How will the ESM work?

A. Southern's return on equity will be calculated annually, based on a fiscal year basis. Southern's fiscal year is the twelve months ending September 30th of each year. If the earned ROE, using the DPUC approved cost of capital method, is either below the allowed ROE or within a 100 basis point "deadband" above the allowed ROE, no adjustment to rates will be made. However, if the earned ROE exceeds the allowed ROE by greater than 100 basis points, the "excess" earnings will be divided equally between customers and shareholders. Any resulting rate decrease would be applied to customer bills during the following year.

Q. How will the ESM be calculated in the initial year if rates go into effect after January 1, 2000?

A. The ESM will be calculated based on the twelve months ended September 30, 2000, even if the rates established in this proceeding go into effect after January 1, 2000. The ESM calculation will be based on a three-month period from October 1, 2003 through December 31, 2003 at the conclusion of the rate plan.

Q. How does the ESM compare with the Commission's examination of Southern's earnings under the current regulatory review process?

A. Southern has structured the ESM component of the PBR plan to be similar in many respects to the current earnings review process. For example, under the current process, an excess earnings review is not triggered until Southern earns at least 100 basis points above the allowed ROE for six consecutive rolling 12-month periods. Furthermore, no provision is made to increase rates should the earned ROE fall below the allowed ROE unless Southern files for an increase in rates.

Under the ESM proposal, Southern would continue to provide the Commission with the information required to verify its earned ROE each month based on a rolling twelve-month historical period. As indicated above, the ESM calculation would be based on the earned ROE calculated for the twelve months ended September 30th of each year.

The more important distinction between the current and proposed approaches is that there will be no need for the Commission to conduct a litigated proceeding to examine excess earnings and to determine whether the overearnings were likely to continue into the future or whether they would benefit customers. It is therefore quite conceivable under Southern's proposal that customers would share in earnings above the allowed ROE even if it was unlikely that the Southern would continue to earn at such levels. The "automatic" nature of the ESM would preclude Southern from making the claim that the earnings were the result of extraordinary circumstances.

Q. How will Southern's customers benefit from the ESM mechanism as it has been structured by Southern?

A. The ESM mechanism provides Southern's customers with an effective and administratively efficient mechanism to share in benefits that are generated from activities that either reduce costs or increase revenues. At the same time, they are not only insulated from sharing on the downside, but are protected from a rate increase for a minimum of four years, unless Southern experiences financial hardship that results from extraordinary circumstances.

Q. Why is the ESM superior to the existing approach?

A. The ESM approach is more likely to lead to behavior that generates long-term benefits to customers and provides for an administratively efficient mechanism of sharing the benefits with customers. Southern believes that the time that is currently devoted to the excess earnings reviews by all parties can be spent more effectively if devoted to other important activities.

Service Quality Plan

Q. Why did Southern decide to include a SQP as part of its proposal?

A. State regulatory commissions throughout the country have expressed a concern that utilities operating under a PBR mechanism may have an incentive to cut costs in a manner that results in a deterioration of the quality of service provided to customers. A SQP provides a means for regulatory commissions to monitor performance in this area and sends a message to customers and the utility that service quality should not be allowed to suffer as utilities pursue more efficient operations. Southern's commitment to providing service of the highest quality has not changed and it believes that incorporating a SQP as a key element of its PBR proposal is entirely appropriate.

In fact, this commitment and its relationship to the goal of operating efficiently is reflected in the language used to express one of the Company's key strategic objectives:

- **Aggressively control operating and maintenance expenses to maximize efficiency and reduce the cost of service, while maintaining the existing high level of safety and quality of service.**

Q. What were the Company's overall objectives in developing the SQP?

A. Southern's development of the SQP was guided by the following objectives:

(1) each measure should be of high importance to Southern's customers, the DPUC, and to Southern;

(2) the ability to perform under each measure should be largely within Southern's control and not driven by outside factors beyond Southern's control;

(3) implementation efforts required to collect and report the measurement should not be significant or require a costly investment in new business processes or systems; and

(4) the data to be reported to the Commission should either be publicly available or able to be provided under a protective order.

In the UI order, the Commission directed UI to develop between four and ten measures of service quality. In preparing its SQP, Southern wanted to have at least four measures but did not otherwise constrain the evaluation process to arrive at a specific number of measures, and selected all measures that it believes are appropriate.

Q. How many measures are included in Southern's proposal?

A. Southern is proposing to implement five service quality measures:

(1) ***Customer Satisfaction***: as represented by a statistically valid survey instrument that measures the satisfaction of customers that have recent contact with the Company, including its customer service personnel and field technicians (the survey instrument currently measures the performance of the Company based on 34 distinct "characteristics");

(2) ***Call Center Responsiveness***: as represented by the average time in seconds that a customer waited in queue for a resource capable of addressing their inquiry, which could be an agent or an automated process;

(3) ***Suspected Gas Leak Call Responsiveness***: as represented by the percentage of calls that are reported as suspected gas leaks on a customer's premises that are responded to within DPUC Staff guidelines;

(4) ***Service Call Responsiveness***: as represented by the ability of the Company to meet scheduled 4-hour appointment windows for four types of service calls (no-heat service calls, turn-on service calls, no hot water service calls, and legal meter changes); and

(5) ***Billing Based on Actual Meter Reads***: as represented by the ability of the Company to provide customers with bills based on an actual meter reading, expressed as a percentage of customer bills that are generated based on an actual meter reading.

Each of these measures is described in considerable detail in the testimony of Mssrs. Ardigliano (measures 2, 3 and 4) and Loomis (measures 1 and 5) which includes the specific definition of each measure, a proposed benchmark against which future performance will be measured, and the information that will be reported to the Commission during the term of the PBR plan.

Q. How did Southern decide which measures to include in its proposal?

A. Southern expended considerable time and effort to identify potential measures, subject them to an evaluation process to develop a short-list of the most promising measures, and refine the definitions. The process involved individuals from throughout the organization including the senior management team, but particularly those that are responsible for the customer care activities.

Although service issues in the natural gas industry are different in some significant respects from the electric industry, the Commission's guidance provided in its order on the United Illuminating PBR proposal was also helpful.

Finally, the Company examined the SQPs from other LDCs in the region to identify the measures that have been implemented by other utilities.

Q. What types of measures were considered but not included in the final list of proposed measures?

A. Southern considered several measures that are not included in its proposal. For example, the Company considered measures that would directly measure the safety of its operations. These included both an employee safety measure (based on lost work time) and a community safety measure (based on damage to Southern's mains and services for which it is responsible). These were rejected as either being less important from the perspective of customers (employee safety) or already subject to appropriate Commission oversight authority (community safety).

The Company also considered measures that would address the satisfaction of retail marketers as customers but concluded that it is still premature to define and implement such a measure at this time, even on a pilot basis.

The measure that received the greatest consideration but was ultimately excluded from the SQP proposal was a customer complaint measure that would be based on complaints received regarding Southern's performance by the DPUC.

Q. Why did Southern decide not to propose the DPUC-based customer complaint measure at this time?

A. There are legitimate concerns regarding such a measure from both the DPUC and Company's perspective. From the Company's perspective, it believes that it would be necessary to work with the DPUC to develop a data collection process that was consistent with the existing DPUC Scorecard process, but which provided for a more precise and perhaps stringent definition of calls which are logged as "complaints". Under the current Scorecard process, there are some calls which are more appropriately characterized as "inquiries" regarding

Southern's billing or other practices than as "complaints". This may be appropriate for the purposes of preparing the DPUC Scorecard, but may not be appropriate for purposes of a SQP measure.

More importantly, Southern believes that the Customer Survey measure, if properly designed and conducted, is a superior way to measure customer attitudes toward the Company and to evaluate their satisfaction with interactions that they have had with Company personnel.

Q. Is the Company aware that the DPUC has expressed reservations about the reliance of customer survey instruments as a service quality measure?

A. Yes. UI, in its initial PBR proposal, proposed a measure that was based on a customer satisfaction survey. In rejecting the use of a survey by UI, the Commission raised concerns regarding the ability to make the results available to the public, the weighting scheme to be applied to the responses to various survey questions, and the general reliance on survey instruments for regulatory oversight.

Q. What steps has Southern taken to address these concerns?

A. Southern's proposed survey measure, as discussed in the testimony of Mr. Loomis, addresses some of the Commission's concerns. Southern proposes to make the survey instrument and summary results publicly available. In addition, there is no complicated weighting scheme – the scoring is based on a simple average of the responses to 34 questions in three categories:

- General Company ratings (13 characteristics);
- Office/Customer Service Personnel ratings (8 characteristics); and
- Field Technician ratings (13 characteristics).

In Southern's case, the customer survey measure is proposed in addition to four other more specific customer satisfaction measures, which also distinguishes the proposal somewhat from UI's initial proposal.

In addition, Southern proposes to work with the Commission Staff to continue to improve its survey instrument in an endeavor to make it acceptable for both internal and regulatory purposes. Southern has recently completed its second annual customer survey which was designed and conducted by the Center for Research and Public Policy, a firm that is respected as an independent and eminently qualified survey firm. The Center for Research and Public Policy counts both regulatory agencies and utilities among its clients.

If the Commission agrees that the customer survey instrument has potential as a regulatory oversight tool, Southern would propose to involve the Commission Staff in its planning efforts for next year's survey. Thus, Staff would be provided with an opportunity to meet with survey consultant prior to the conduct of the survey to address concerns that it may have regarding the design of the instrument, conduct of the survey, and interpretation of the results.

Q. Why is Southern proposing to exclude financial rewards and penalties at this time?

A. Southern has decided not to propose rewards or penalties at this time for several reasons. These include:

- Southern's PBR plan does not provide for annual price increases; many proposals that provide for price increases also have a SQP with a graduated penalty structure;

- the reasoning applied by the Commission in rejecting UI's proposed reward/penalty structure also applies to Southern, namely, that Southern's objective should be to maintain its existing high quality of service during what is expected to be a period of transition to a competitive market structure; and

- as its first PBR plan, Southern has tried to keep the proposal relatively simple; it makes more sense to gather service quality measure data for some period, before applying financial rewards and penalties.

Most importantly, even without financial rewards and penalties, the SQP provides the Department with the ability to monitor quality of service during the term of the plan and assure itself that service quality will not be adversely impacted by the implementation of Southern's PBR proposal.

Cast Iron Main/Bare Steel Service Program Acceleration Option

Q. Why is Southern offering to accelerate its cast iron/bare steel replacement program?

A. Southern believes that an acceleration of its cast iron/bare steel replacement program is in the public interest as it improves the safety and reliability of its system, <u>but only if</u> it can be accomplished with an acceptable rate impact.

Over the past several years, Southern has been replacing approximately 855 services and 7 miles of mains per year in its replacement program. The factors that have limited a more aggressive replacement program are concern over revenue impacts (as these "replacement" investments generally do not contribute to increased throughput) and Southern's ability to manage the engineering construction effort.

Q. Does the rate freeze reflect any capital expenditures in this area?

A. Yes. The rate freeze commitment reflects a continuation of Southern's program to replace the cast iron mains and bare steel services on its system by investing approximately $5 million per year. In order to maintain this level of non-revenue producing investment and avoid an earnings deficiency, Southern must either decrease costs or increase net revenues by approximately $1.0 million each year. However, Southern is proposing to accelerate this program for the term of the rate plan by increasing the annual expenditures by as much as 60 per cent or $3 million per year if the Commission authorizes recovery of the depreciation, taxes and return on investment associated with this incremental investment.

As the investment required per service and per mile of main can vary significantly, Southern proposes that a cap on incremental expenditures be set at $3 million per year to be divided between service replacements ($1.75 million) and main replacements ($ 1.25 million) and that the total expenditures be capped at $8 million per year. The split between service and main replacements maintains the emphasis on these investments that is in the current replacement plan. Although Southern may have to use some overtime work to handle the engineering and construction management effort, the Company believes that it can accommodate this level of acceleration in the program.

Q. What increase in customer rates would be required to accommodate the acceleration of the bare steel/cast iron replacement program?

A. An increase of $3 million in Southern's program would result in an increase in total revenue requirements of approximately $0.6 million per year. In percentage terms, average margins would increase approximately 0.5 % per year and total rates would increase by approximately 0.3% per year to accommodate this level of expenditures. It is important to note that potential acceleration of this program is facilitated by the commitment to freeze rates based on an assumption that replacement investments continue at their current level. In other words, if other areas of Southern's operations were likely to contribute to a need to increase rates, the rate impact attributable to accelerating these investments may no longer be acceptable.

Rate Relief Conditions

Q. Please describe the conditions under which the plan can be revisitied.

A. There are two categories of "exogenous" events that will require that the PBR plan to be revisited by the Commission. The first of these are events that require that rates be recalculated. There are also conditions under which the plan should be terminated.

Q. What factors will lead to a need to recalculate rates under the plan?

A. There are certain events that cannot be anticipated by Southern or by the Commission that would require rates to be recalculated (either increased or decreased) during the term of the plan if they have a material impact on Southern. These are:

(1) A legislated change in a federal or state tax rate;

(2) A change in a tax law or accounting standard;

(3) A change in a law or regulation;

(4) Environmental clean-up costs which require a current expense;

(5) Litigation involving Southern that results in either a significant windfall gain or loss (e.g., resolution of an environmental remediation or property tax suit); and

(6) An "Act of God".

Q. Are these factors typical of PBR plans?

A. Yes. This is a fairly standard and limited list of conditions under which rates would be recalculated during the term of a PBR plan.

Q. What factors will led to a reopening of the plan?

A. The plan would be terminated at Southern's option, or in effect, Southern would be required to file a new rate case if one of the following conditions occurs:

(1) Either the rate of inflation increased by 150% or the prime rate increased by 100% or more from the levels that exist today (2.1% for inflation as measured by the CPI, and 7.75% for the prime rate);

(2) The 30-year treasury rate increases by 50% or more from its current rate of 5.96 %; or

(3) Southern's earned ROE falls below its allowed ROE by 200 basis points or more.

The third condition is fairly standard in PBR plans. The first two conditions are really less direct measures of the same consequence, namely adverse economic conditions that result in a significant deterioration in Southern's financial condition. These conditions were included in Southern's 1993 rate settlement, approved by the Commission in Docket No. 93-03-09.

Q. When would Southern make compliance filings under the PBR plan?

A. Southern would make annual compliance filings under the plan to provide information on both its financial performance and SQP measures. The impact of the earnings sharing mechanism and, if approved, accelerated bare steel/cast iron replacement program, would be calculated on a calendar year basis.

The resulting change in rates would be applied over the next twelve months beginning on the anniversary date of the effective date of rates to be established in this docket. Any rate increase or decrease would be applied to the volumetric portion of the rate design for all firm customers and would be shown separately on the bill. However, if the impact is relatively minor, Southern may propose to implement the resulting change over a much shorter period, and perhaps during a single billing period if the impact is minor.

Q. Why is Southern reserving the right to decline to implement the PBR plan?

A. Southern is reserving the right to decline the PBR plan because it is the only reasonable recourse available to the Company should the Commission modify the plan in a manner that is untenable to the Company. Having said that, it is important to note that the Company is making this proposal because it believes strongly that it serves the interests of its customers and shareholders, and will be viewed positively by the Commission as well.

The direction that I received from Southern was to assist the Company in developing a proposal that would be acceptable to the Commission without modification. I believe that this proposal accomplishes this objective, but I do not presume to substitute my own judgement for the Commission's in this regard.

V. SUMMARY AND CONCLUSION

Q. Please summarize your recommendation that the Commission approve Southern's PBR proposal without modification.

A. In summary, Southern's PBR plan should be approved because it accomplishes the following objectives:

(1) it provides rate stability and certainty to Southern's customers over a four-year period;

(2) it insulates Southern's customers from many of the risks that will be facing distribution companies over the next four years;

(3) it provides an opportunity for customers to experience lower rates if Southern is able to increase its earnings as a result of operating more efficiently or successfully competing to attract new load;

(4) it provides Southern with a clear incentive to pursue activities that result in operating efficiencies or profitable new load;

(5) the bare steel/cast iron replacement option, if implemented, will improve the safety and reliability of Southern's distribution system;

(6) the SQP provides the Commission with an assurance that Southern's commitment to providing service of the highest quality will continue and provides the Commission with a formal mechanism to track its performance in this area; and

(7) it provides Southern and the Commission with some additional time and resources to devote to important unbundling issues.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

Annexe E

SUPPLEMENTAL DIRECT TESTIMONY

Q. Are you the same Robert C. Yardley, Jr. that has submitted prefiled testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental testimony is to comment on the Rate Plan Alternative or "RPA" that was presented in the testimony of Messrs. Bonner and Adams and to provide my perspective on the relationship between the RPA proposal and the PBR proposal that I presented in my initial testimony.

Q. Why were two alternative rate plans developed and proposed by Southern?

A. As I indicated in my initial testimony, I was retained by Southern in early 1999 to help them develop a PBR proposal. This effort predated the April 23, 1999 announced merger with Energy East. As a consequence, the design of the PBR did not contemplate that Southern would potentially become part of a much larger entity with distribution affiliates throughout the region. The RPA, on the other hand, reflects the operation of Southern as a subsidiary of Energy East and was developed in this context. In fact, the ability of Southern to implement the RPA is contingent upon consummation of the merger. Due to the need to obtain various regulatory approvals, the anticipated timing of those approvals and the timing of this proceeding, it was appropriate to present both proposals to the Commission.

The enhancements in the RPA, which I will summarize below, are made possible by the capabilities that Energy East brings to the table, including both operational and financial capabilities. Therefore, it is not reasonable to "mix and match" elements from the two proposals and apply the result to Southern as a stand-alone company.

In other respects, the two proposals are complementary rather than competing proposals, with the PBR proposal providing a reasonable transition to the enhanced RPA proposal. The PBR, including the Service Quality Plan, can be implemented in January, 2000 when the rates established in this proceeding go into effect. However, the RPA cannot be implemented until the merger is consummated <u>and</u> until the 1999/2000 PGA cycle is complete. This additional time will be put to good use as it provides Southern with an opportunity to inform and educate customers regarding the options that are being made available as part of the RPA. It will also provide the time necessary to modify business processes and systems that are necessary to support these options (e.g, developing gas supply hedging processes and training of call center personnel).

Q. How does the RPA compare to the PBR that you have sponsored?

A. I have prepared a matrix, attached to my testimony as Exhibit ____, which compares the two proposals to assist the Commission and other parties in identifying the areas in which the proposals are similar (if not identical) and where they are different.

As demonstrated in this matrix the proposals are virtually identical in many respects, particularly those that focus on the distribution services provided by Southern. Both proposals fix the recovery of per unit non-gas costs for the term of the plan, incorporate identical Service Quality Plan measures, include an option to accelerate the bare steel/cast iron replacement program, and provide for the same limited list of "exogenous factors". They are each four year plans, but the transition from the PBR to the RPA plan in September 2000 actually results in a combined term of approximately 56 months, from January 2000 through August 2004.

However, the proposals differ in four significant ways, which are each attributable to the increased risk that Southern, as a subsidiary of Energy East, would be able to absorb. They are as follows:

1) The PBR proposal was directed toward the non-gas or base rate portion of customers' bills; the RPA proposal offers enhancements that address gas costs as well, resulting in an incentive program that focuses on the customers' total cost of gas service.

2) The RPA proposal eliminates the three PBR plan "reopeners" that I have suggested are appropriate for Southern as a stand alone entity. One of these reopeners provides Southern with the ability to file a rate case before the expiration of the term of the plan if its earned ROE falls below its allowed ROE by 200 basis points or more. As a subsidiary of a larger entity, Southern would be able to absorb the risk of being precluded from such a re-opener.

3) The earnings sharing mechanisms are different under the two proposals.

4) Southern would be allowed to enter negotiated contracts with customers that use over 5,000 dth annually pursuant to a flexible tariff under the RPA proposal.

There are other differences, of course, but these are the critical distinctions between the two proposals.

Q. In your opinion, how should the DPUC view the two proposals?

A. Setting aside the relationship of the RPA proposal to the proposed merger for the moment, the two proposals draw distinct boundaries around the costs (and therefore, the utility activities) to be addressed by way of an incentive mechanism.

The RPA proposal is an enhanced version because it includes virtually all of the regulated activities of Southern, including gas supply purchasing and merchant sales activities. The PBR proposal covers distribution costs and related activities. The gas cost related enhancements provided by the RPA proposal would be implemented approximately eight months after the base rate PBR, providing for a smooth transition and include time to educate commercial and industrial customers about the new pricing options.

Most importantly, both proposals provide the DPUC with an alternative to the current rate-setting approach. Moreover, both proposals provide tangible benefits to Southern's customers and are preferred to a continuation of the current approach.

The two proposals provide the Commission with an opportunity to review the two most prevalent forms of performance-based regulation in the natural gas industry: distribution cost or base rate incentive proposals and gas cost incentive mechanism ("GCIM") proposals. In some cases, the two are formally linked together to present a proposal that focuses on what is of most importance to customers: the total cost of gas delivered to the customer's premises. The United Illuminating proposal, which I discussed briefly in my initial testimony, would be considered to be an example of a combined approach, as it virtually fixes UI's Fuel Adjustment Charge for the term of the plan. The RPA falls into this category as well. It provides customers with stable and predictable rates for the total delivered cost of gas. The simplicity of a fixed total rate is also valued by customers.

Q. Please comment on the relative merits of base cost and gas cost incentive mechanisms.

A. Both approaches have considerable merit as alternatives to more traditional regulatory approaches because they encourage behavior that can provide tangible benefits to customers and improve upon some of the inherent weaknesses in the current approach to rate setting.

However, GCIMs must be designed to reflect the fact that the degree of control that an LDC has over gas supply costs is substantially different than its ability to control distribution costs. Southern, as a subsidiary of Energy East, would be able to shift more of this risk toward shareholders and away from customers than could

Southern as a stand alone entity. Specifically, the gas cost portion of the bill is subject to a much greater extent to market forces, with these forces playing an increasingly significant role under the policy guidance of the FERC. These policies have created "physical" markets for both commodity and capacity, as well as new financial markets that enable buyers and sellers to hedge the price risks that are associated with their participation in the physical markets.

Q. Please expand on the most significant distinctions between the two proposals.

A. The matrix in Exhibit ____identifies three important components that are included in the enhanced RPA proposal but not included in the PBR proposal:

1) the elimination of the effect of the PGA clause for residential customers (which has the effect of making the price cap a "total price, including gas cost, cap");

2) the option provided to non-residential customers to select either a fixed or indexed price for the gas supply portion of their bill; and

3) the request to enter into negotiated contracts with large customers pursuant to a flexible tariff.

The other two areas in which the RPA proposal differs from the Southern PBR proposal are:

4) the elimination of the proposed PBR "reopeners"; and
5) the different earnings sharing mechanism in the RPA proposal.

These five distinguishing components of the RPA proposal are integrally related, as I shall discuss below. There is one other difference between the two proposals but I would consider this to be less important and not necessarily integrally related to the rest of the plan: the proposal to implement BTU billing.

I have not included the request for an exemption from the Commission's currently effective policy regarding hedging transactions in my matrix. I would characterize this request as an "enabling" element of the RPA proposal rather than as a distinguishing characteristic. While several LDCs have requested permission from their regulatory agencies to engage in hedging transactions (frequently referred to as price risk management or "PRM" tools) with the costs recovered through a PGA mechanism, it is simply not possible to either eliminate the effect of the PGA or to offer a fixed price option to a significant number of customers without having the ability to enter into these types of transactions. Stated simply, if the Company is not granted the authority to engage in physical and financial hedging transactions, it would be unable to manage the risks associated with eliminating the PGA for residential customers or FPO offer for non-residential customers. In other words, in order to shift the volatility of gas cost risks away from ratepayers and toward shareholders, the Company must have the ability to employ tools to enable it to manage that risk. The concerns raised by the existing DPUC policy regarding the sharing of gains and losses are no longer relevant as the Company would be absorbing all of the risk associated with these transactions.

Q. Why do you view the five components that you have identified as being integrally related?

A. Taken as a group, they define the source of the increased risk that shareholders are willing to absorb (the elimination of the effect of the PGA clause, the fixed price option, and the elimination of the reopeners) and identify the fair compensation to shareholders for absorbing this increased risk (the different earnings sharing mechanism).

While both proposals insulate customers from any earnings shortfalls and share any earnings above a threshold equally, the threshold differs and the timing and manner in which earnings are calculated also differ. As I indicated in my initial testimony, the ESM in the PBR is modeled after the current earnings sharing review process.

The ESM proposed in the RPA must correspond to the risks attributable to this proposal.

Q. How is the RPA proposal "contingent upon and enabled" by the merger?

A. Southern, absent its merger with Energy East, cannot offer the gas supply benefits that are the defining attributes of the RPA proposal. Most importantly, Southern could not absorb the increase in risk associated with the elimination of the effect of its PGA clause. The ability of an LDC to absorb the price risk associated with gas price volatility is a function of size.

In addition, although Southern probably could offer the FPO and IPO options to its non-residential customers, it cannot do so nearly as efficiently as it will be able to do so as a result of its combination with Energy East. In order to offer the FPO and IPO options, Southern would have to develop the capability to employ price risk management tools, including the internal policies, guidelines and audit procedures that ensure that they are used appropriately. The ability to take advantage of physical and financial market tools is also directly related to the size and diversity of an LDC's portfolio and the geographic span of its load centers.

Energy East, with its recent utility acquisitions, has the ability to propose and implement a more expansive and higher risk incentive proposal than Southern could on a stand-alone basis. This results from Energy East's:

- strong balance sheet and financial condition;
- capability and experience in the use of price risk management tools; and
- presence in the northeast natural gas market.

Energy East's financial strength may also explain why it believes that it can live without the inflation, interest rate, and ROE reopeners that are described on page 20 of my initial testimony.

Q. Please comment on the different earnings sharing mechanisms in the RPA and PBR proposals.

A. The RPA and PBR proposals differ in three respects: (a) the formula used to calculate earnings, (b) the threshold level at which earnings sharing will begin, and (c) the length of the period over which the earnings are calculated for purposes of sharing any excess earnings.

The PBR utilizes the cost of capital approach to calculate the ROE; the RPA proposal utilizes a net income approach. As I indicated in my initial prefiled testimony, the earnings sharing mechanism in the PBR proposal was specifically designed to mirror the existing earnings review process as closely as possible, despite the concerns regarding the cost of capital approach that are expressed in Ms. Forest's testimony. The net income method more accurately reflects the actual return earned by the Company.

Again, in an effort to mirror the existing earnings review process as closely as possible, the PBR establishes the threshold at which earnings would be shared at 100 basis points above the allowed ROE. The RPA sets the threshold at 13.50 percent.

Finally, under the RPA, the calculation of earnings for purposes of determining any sharing would be done on a biennial basis, as opposed to annually. This latter difference is attributable to the nature of the market and financial risk associated gas cost related aspects of the RPA proposal.

Q. Please summarize your conclusions with respect to the RPA and PBR proposals.

A. Both proposals represent a significant improvement over the current rate-setting approach and will provide tangible benefits to Southern's customers. The benefits of the PBR proposal were presented on pages 21-22 of my initial testimony. The

RPA proposal, made possible by the merger with Energy East, extends those benefits significantly by addressing the total cost of gas paid by Southern's customers.

As I indicated in my initial testimony, the PBR proposal provides an appropriate balance between the interests of Southern and its customers, assuming that Southern operates as a stand-alone company. Based on my review of the RPA proposal, I believe that it also reflects an appropriate balance between the interests of Southern and its customers, assuming that Southern is a subsidiary of a Energy East, a significantly larger regional distribution company.

Q. Does this conclude your prepared supplemental direct testimony?

A. Yes, it does.

Annexe F

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Gas Company, As a Gas Public Utility, to Implement a Productivity-based Alternative Ratemaking Mechanism Pilot	))))	Docket 6650-GR-112

TESTIMONY OF ROBERT C. YARDLEY, JR.

Q. Please state your name and business address.

A. My name is Robert C. Yardley, Jr., and my business address is 1050 Waltham Street, Lexington, Massachusetts 02173.

Q. By whom and in what capacity are you employed?

A. I am Executive Vice President and a Director of Reed Consulting Group ("RCG"), a management consulting firm that provides consulting services on a wide range of energy matters to utilities, project developers, industrial companies and governmental agencies.

Q. Please summarize your educational and professional background.

A. I graduated from Georgetown University in 1976 with a Bachelor of Arts degree. I attended Boston College from 1976 to 1980 as a graduate student in economics. I was employed as an economic consultant with RCG and other firms specializing in the regulation of natural gas and electric utilities from 1980 until 1991. In 1991 I was appointed by the Governor of Massachusetts to be Chairman of the Massachusetts

Department of Public Utilities. This agency is responsible for the regulation of all investor-owned electric, gas, telephone and water utilities in the Commonwealth. I served in that capacity until November 1992, at which time I returned to RCG. My experience is summarized in Attachment A, designated as Exhibit No. ______ (RCY-1).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Wisconsin Gas Company ("Wisconsin Gas" or "the Company").

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will address Wisconsin Gas' proposal to implement a Productivity-based Alternative Ratemaking Mechanism ("PARM") Pilot. I will discuss this proposal in general terms and will propose a specific margin cap formula to achieve its objectives in a manner that balances the interests of the Company and its customers.

Q. By way of background, please discuss your interest in the issues that are addressed by the Wisconsin Gas proposal.

A. As Chairman of the Massachusetts Department of Public Utilities, I recognized that the traditional rate case regulatory approach has many inherent drawbacks. In fact, many of these drawbacks have been recognized by the Public Service Commission of Wisconsin ("PSCW") in its attempt to move away from annual rate case filings. One of my primary objectives as a regulator was to find less painful ways to achieve the same, if not better, results for ratepayers. In order to achieve some efficiencies in base rate case processes, I pursued this objective by encouraging parties to negotiate multi-year rate settlements. These settlements had results that were similar in many respects to Wisconsin Gas' margin cap proposal.

Second, I attempted to identify areas under our scope of authority in which competitive forces could be relied upon to achieve regulatory objectives. The technological advances in telecommunications made this industry an excellent candidate for alternative forms of regulation. However, as I shall discuss further, competition is playing a much more significant role in the energy industries as well. The challenge for regulation is to find approaches that take advantage of the efficiencies encouraged by competition while continuing to protect the short and long-term interests of ratepayers. While certain tensions are inherent in making this transition from traditional regulation to a more competitive environment, I believe that a properly constructed margin cap mechanism can be a valuable transitional alternative regulation approach while simultaneously reducing the "costs" of regulation.

Q. What is your view with respect to the future of traditional rate of return regulation?

A. Rate of return regulation, under which a utility is allowed to recover costs plus an allowed return on rate base, has traditionally been applied in circumstances in which the services are provided either as a natural monopoly or at least in a non-competitive environment. The underlying theory is that this form of regulation results in prices that would occur in a competitive environment, although it is the responsibility of the regulator to insure that both the level of costs and any investments in rate base are reasonable. This type of regulation has been applied historically to investor-owned electric, natural gas, telecommunications and water utilities. For reasons that I will discuss in my testimony, I consider Wisconsin Gas' PARM proposal to be an appropriate, albeit modest, departure from this form of regulation because it focuses on the achievement of productivity improvements, which simulates the result that would be achieved in a competitive industry.

There have been, of course, many other notable departures from traditional rate of return regulation in recent years, often to recognize the realities of a competitive marketplace. For example, market-based pricing is allowed in many jurisdictions for service to end-users that can also be satisfied by a competitive alternative, such as the dual-fuel (natural gas and oil) industrial market. In other instances, entire sectors of an industry have been deregulated. This occurred, for example, in the market for long-distance telecommunications services.

The bottom line is that competitive conditions are more prevalent in regulated industries than ever before, making it an appropriate time for regulators to analyze alternative approaches to meeting their statutory obligations. Along with meeting environmental concerns, I believe that this is the greatest challenge facing federal and state utility regulators today.

Q. How has the environment faced by regulated utilities changed in recent years?

A. The environment has changed dramatically in each of the regulated industries, with the possible exception of the water industry. The transportation sector is now largely deregulated at both the intrastate and interstate levels throughout the country. The telecommunications industry continues to undergo a major restructuring and there is a realistic possibility of competition at the local level. The electric utility industry is rapidly becoming competitive at the generation level, with the potential for open access on transmission systems ultimately leading to competition for end-users, or retail wheeling. And, of course, the deregulation of natural gas supply and FERC Order 636 have led to a drastic restructuring of the natural gas industry.

Q. What does this imply for regulation of the natural gas distribution industry?

A. The natural gas distribution industry is at a crossroads, primarily as a result of FERC Order 636, but also as a result of increased competitive pressures in end-use markets. The competition that local distribution companies ("LDCs") have historically faced with oil products for the dual fuel market is evolving to include gas-on-gas competition with some LDCs unbundling their own retail services. At the same time, many customers are facing a more competitive market for their own products and will take advantage of competition in the energy market.

Thus, it is appropriate at this time for LDCs and their regulators to examine the terms and conditions under which retail services are provided. From the LDCs' perspective, it is important to take actions to serve both core and non-core customers as efficiently as possible. It will also be more important than ever to develop a regulatory approach that takes advantage of the benefits of more competitive markets.

Q. What role can margin caps serve?

A. Margin caps can serve to focus an LDC's attention on identifying and implementing measures that reduce the cost of delivering quality service to its customers. I also view the adoption of a four-year margin cap as a means of providing breathing room for the LDC and its regulators, allowing them to focus on issues that will shape the future of the industry, while spending less attention and resources on annual or even biennial rate cases. Considered in this context, margin caps can serve a very useful role while the industry is in transition from cost-based regulation to a more competitive environment. A margin cap provides an incentive for the LDC to produce the same or improved service at a lower cost, which is similar to the result that would be achieved in a more competitive market. By margin cap, I am referring to Wisconsin Gas' proposal to establish an annual percentage change in the margin to be recovered from each class of customers which, by definition, would exclude costs of delivering the gas commodity to the city-gate. As discussed in the Team testimony, Wisconsin Gas has excluded the cost of gas from the margin cap. I believe it is appropriate to exclude the cost of gas at this time due to the uncertainty of forecasting and controlling the cost of gas in a post Order 636 environment.

Q. How does a margin cap advance the objectives of regulated utilities, their customers and the regulators?

A. No one can be certain how the natural gas market will change over the remainder of the decade, but it is clear that the environment in which LDCs market their services will be more competitive. It is also clear that customers will demand more of LDCs than in the past, particularly the largest customers that face intense competition in their own product markets. A margin cap will provide many benefits to prepare all of the affected parties for this environment.

The customers will be guaranteed annual rate increases that are lower than the level of inflation, reflecting a built-in commitment to improvements in productivity. They will also have a greater degree of price certainty over the four-year period, a consideration that is of increasing value to industrial and large commercial customers. Certain classes of customers will also be able to benefit from rates established below the cap as Wisconsin Gas responds to market conditions, and they will not have to engage in a burdensome regulatory process in order to do so.

Wisconsin Gas, as described in some detail in both Mr. Schrader's and the Team testimony, will be encouraged to seek out permanent productivity improvements. They will also be free to focus on serving customers by providing reliable, safe service at a reasonable cost. This customer focus clearly represents the shape of the natural gas industry in the future.

The PSCW, for its part, will free up considerable staff and Commission resources to devote to more important long-term issues facing all of the industries that it regulates.

Q. How does the ratemaking process affect the utility's incentive to achieve long-term productivity improvements?

A. Under traditional rate of return regulation, utilities have an incentive to control costs because in the near term all savings flow to the bottom line until the next rate review. Thus, annual, and even biennial, rate proceedings create a short-term focus on utility productivity.

Wisconsin Gas' proposal is intended to provide a greater incentive to achieve long-term productivity gains. The provision for prices to rise, but at a rate less than the rate of inflation, enables Wisconsin Gas to maintain reliable service to existing customers and to serve new customers. In addition, it provides customers with a valuable long-term guarantee. Considered in this context, the benefits of a four-year pilot instead of a two-year approach are obvious. Quite simply, it will provide the management team with the ability to not only develop, but to also implement and evaluate the results of long-term productivity improvements.

Q. How does the PARM serve as a transition to a more competitive energy sector environment?

A. As I indicated earlier, the considerable resources of all parties that were devoted to the annual rate case filings can now be devoted to the more challenging issues currently demanding attention. Each of the industries regulated by the PSCW is undergoing dramatic structural changes. Considerable effort is needed to develop appropriate corporate and regulatory responses to this new environment, which is why I believe that a four-year margin cap will serve the ratepayers' long-term interest if adopted at this time.

Q. What objectives should be kept in mind in constructing a margin cap mechanism?

A. I should begin by noting that it is important that the objectives of any alternative regulatory scheme be clearly identified. Some of these objectives will have a short-term focus; others will persist in the longer term.

First and foremost, the four-year PARM with a margin cap should provide additional incentives to Wisconsin Gas for obtaining permanent productivity improvements that can be passed on to its customers, both during the pilot and at the time of the next base rate case.

Second, the margin cap should result in more stable rates for the four-year pilot term, while preserving the ability of Wisconsin Gas to lower rates to certain customer classes in order to respond to competition.

Third, the margin cap should be understandable to customers and defensible from a public policy perspective. By this I mean that it is the responsibility of both Wisconsin Gas and the PSCW to explain the objectives of the PARM and how it will affect customers' bills during the pilot term.

Fourth, the margin cap should reduce the costs of regulation that are incurred by all parties either under the annual rate case process that has been in place or the biennial process that has recently been implemented.

Fifth, as I discuss later in my testimony, the margin cap should apply to expenditures that can reasonably be expected to be controllable and thus subject to productivity improvements.

Sixth, it should contain reasonable and appropriate mechanisms to evaluate, alter and abandon the pilot, but these should be as limited as possible.

Seventh, the end result should be fair and acceptable as an alternative form of regulation to Wisconsin Gas, its customers and investors, and the PSCW.

Q. What is the form of the margin cap Wisconsin Gas is proposing?

A. The margin cap proposal is more fully set forth in the Prepared Direct Team Testimony. The proposed margin cap would place a limit on the recoverable margin from rates for a four-year period. Although the cap will serve as the upper limit for the percentage increase in rates for each rate class, Wisconsin Gas would have the flexibility to adjust rates below this cap to reflect cost savings and productivity improvements and to respond to competition. The cap would be adjusted annually by a factor calculated as the difference between the inflation rate and an appropriate productivity factor for Wisconsin Gas. This form of margin cap is commonly referred to as the "CPI-X" approach. A Weather Adjustment Mechanism is also included in the plan to account for the unpredictability of the weather. This clause stabilizes the size of customers' bills and the Company's earnings by avoiding large fluctuations due to abnormal weather.

Q. Why is it appropriate to include a measure of inflation in developing the margin cap?

A. It is appropriate to include a measure of inflation because, quite simply, Wisconsin Gas' input costs required to produce a unit of service can be expected to increase at some representative level as a result of general inflationary forces.

Q. What factors should be considered in selecting an inflation factor for the margin cap?

A. The inflation factor is included as part of the index to the margin cap to recognize the price increases that are occurring in the overall economy. There are several measures of inflation that could be used as an appropriate index for the Wisconsin Gas margin cap proposal. The measure selected should be broad-based, to reflect the diverse nature of the Company's labor and materials costs, and stable, so that data collection anomalies do not affect the Company's rate ceiling.

Two widely-recognized measures would meet these objectives, the Consumer Price Index For Urban Consumers ("CPI-U") and the Gross National Product Fixed-Weight Price Index ("GNPPI"). The CPI-U focuses on the prices of consumer goods, rather than the prices of industrial commodities. However, the CPI-U is a good proxy for escalation in labor costs, is broad-based and stable, and is available for the U.S. as a whole and for individual regions such as the Milwaukee Standard Metropolitan Statistical Area ("SMSA").

The GNPPI reflects price changes for all of the goods and services produced as part of the U.S. economy. The GNPPI is a fixed weight, broadly-based and stable index. Unlike the more widely quoted G.N.P. Implicit Price Deflator, the GNPPI tracks only price increases and excludes any consideration of shifts in output composition. Therefore, it is a better measure of purely price changes than the implicit price deflator.

Q. Which of these inflation measures do you recommend?

A. I have selected the GNPPI as the most appropriate benchmark of inflation for use in the margin cap mechanism. By its inclusion of both industrial and consumer goods, it more closely mirrors the Company's input mix and costs. For comparative purposes, I have also shown the national CPI-U in my exhibits as an alternate inflation index. The GNPPI was selected by the Federal Communications Commission for its cost cap regulation of AT&T, and has been recommended as the appropriate inflation index in state-level ratemaking mechanisms for the telecommunication industry.

Q. Please explain what is implied by the concept of productivity and its relevance to the margin cap proposal.

A. Productivity is an economic concept that is generally defined as measurement of the value of resources of "inputs" required to produce a unit of "output". The most common inputs are labor, capital, and materials and the "output" is usually a good or service whose characteristics are assumed to be constant over the period in which productivity is being measured. Improvements in productivity, therefore, can be realized by either reducing the units of inputs required to produce the unit of output or by combining inputs in a more productive way to produce a unit of output. Improvements in productivity are related to the concept of economic efficiency because only those firms that are most productive and therefore achieve the lowest cost of production will survive in a competitive market environment in the long run.

The productivity, or "X" factor, is an important part of the margin cap proposal, because it provides that consumers will automatically receive the benefit of a specified level of productivity improvements, rather than having to wait until the next rate change to receive these benefits. It will be up to Wisconsin Gas to achieve the productivity gains by looking throughout its business for opportunities to provide the same or better quality of service at lower cost. In so doing, Wisconsin Gas will have an incentive to act much like a firm in a competitive environment.

Q. How do productivity changes in the natural gas industry compare with the telecommunications industry, which has been subjected to price cap regulation at both the federal and state levels?

A. There are distinct differences between the types of productivity gains that can be achieved in these two industries. Most importantly, the potential for technology-driven productivity improvements are significantly different. The telecommunications industry is undergoing technological advancements, particularly in the network facilities, that support existing and future services. These technological advancements are the principal source of productivity gains in the telecommunications sector. Productivity gains in gas distribution systems are unlikely to be driven by technological change, but are much more likely to be the result of management performance and operational efficiency.

Q. What productivity factor do you recommend be used as part of the PARM?

A. Based on my analysis of company-specific financial data, I recommend that a 0.5 percent per year productivity factor be used as part of the PARM. Therefore, the specific margin cap formula that I am recommending is GNPPI minus 0.5 percent per year.

Q. What analyses have you performed to determine the appropriate productivity offset?

A. For my analysis, I utilized the portfolio of seven gas utilities that has been selected by the PSCW staff as comparable to Wisconsin Gas. This portfolio is used by the Company and Staff in rate proceedings in determining the required return on equity. These LDCs are Atlanta Gas Light, Bay State Gas, Brooklyn Union Gas, Indiana Gas, Northwest Natural Gas, Piedmont National Gas and Washington Gas Light.

For each of these LDCs, the revenue requirement was calculated annually from 1978-1992. The calculation summed operations and maintenance ("O&M") expenses, depreciation and amortization, and taxes other than income taxes. The final part of the revenue requirement was the authorized pre-tax return on rate base. To determine this return, Wisconsin Gas' most recent authorized pre-tax rate of return of 14.87 percent was used for all Companies for all years. This return was added to the O&M expenses, depreciation, and other taxes to arrive at the total revenue requirement for each LDC. The total revenue requirement was divided by gas sales to determine the appropriate revenue requirement per unit of sales for each of the

LDCs.

A constant pre-tax return on rate base was used because the historical data for the comparable companies contain trends of lower tax rates, lower costs of capital, earnings generally below authorized levels, as well as changes in capital structure. These trends cannot be assumed to continue. In fact, the fundamental premise of the PARM is that future changes in these cost elements should not be built into the cost cap. It is therefore necessary to use a constant pre-tax rate of return on rate base to adjust out these trends. The elimination of the effects of past changes in capital structure, rate of return, or tax rates puts the historical data on the same basis as the forecast to be used in the PARM.

Exhibit No.___(RCY-2) shows the raw cost data for all seven comparable companies, as well as the development of constant return revenue requirements. As previously discussed, the analysis used a 14.87 percent pre-tax rate of return for all of the companies. Since the pre-tax rate of return is held constant over time, and the analysis focuses on the changes in overall revenue requirements over time, the absolute level assumed for pre-tax rate of return becomes immaterial.

Q. What are the results of your comparable LDC analysis?

A. As shown at the bottom of Exhibit No.___(RCY-3), the weighted average compound annual growth rates in constant return revenue requirements for the seven companies range from 5.4 percent over the longest interval (14 years) to -0.95 percent over the shortest interval (1 year). Intervals of less than three years are probably not very meaningful due to the possibility of the results being skewed by one abnormal period. The weights used to produce the average are each LDC's total revenue requirement. The simple average of the cumulative growth rates for the seven LDCs produces results that are virtually identical to the weighted average analysis, as shown on the last line of Exhibit No.___(RCY-3).

Q. How do these growth rates compare to your proposed measures of inflation?

A. The growth rates for the LDCs' revenue requirements were compared to inflation measures on Exhibit No.___(RCY-4). On this Exhibit, compound annual average growth rates in the LDCs' revenue requirements are presented for all of the time intervals, for both the weighted average and the simple average. These growth rates were then subtracted from the proposed inflation measures to determine the comparable LDC productivity offsets. These calculations were performed using both the GNPPI and the CPI-U as measures of inflation.

As shown on Exhibit No.___(RCY-4), over longer intervals, revenue requirements per unit of sales have typically increased faster than inflation, regardless of whether one uses the GNPPI or CPI-U as the measure of inflation. For example, for the interval of 1979 to 1992, the weighted average increase in revenue requirements per unit of sales was 5.55 percent per year, while the GNPPI increased at an average rate of 4.71 percent per year, yielding a negative productivity factor of 0.85 percent per year. Over shorter intervals, revenue requirements per unit of sales have increased more slowly than inflation. For example, over the interval of 1986 to 1992, the weighted average increase in revenue requirements per unit of sales was 2.94 percent per year, while the GNPPI increased at an average rate of 3.82 percent per year, yielding a positive productivity offset for all intervals of 0.89 percent per year. The average of all intervals based on the weighted average growth in revenue requirements (except the one year interval of 1991-1992) is -0.09 percent per year when compared to the GNPPI, and 0.189 percent per year when compared to the CPI-U.

Use of the simple average growth rate in revenue requirements results in an average productivity offset for all intervals of -0.064 percent per year when compared to the GNPPI and 0.218 percent per year when compared to the CPI-U.

The average of the productivity offset values for the thirteen intervals is comparable to an end-weighted average of the differentials in yearly growth rates, since data for the later years influenced more of the intervals than data for earlier years. Therefore, I have adopted the values of -0.09 percent, 0.19 percent, -0.06 percent and 0.22 percent per year as the best point value estimates of historically achieved productivity offsets, as shown on Exhibit No. ___(RCY-4).

Q. Please summarize your conclusions.

A. From Exhibit No.___(RCY-4), I have concluded that the historical data indicate that comparable LDCs' growth in revenue requirements per unit of sales have been almost exactly at the rate of inflation. This would suggest that no productivity offset should be built into the PARM margin cap mechanism. However, the data also show that over the most recent periods, the LDCs' unit costs have increased at rates less than the rate of inflation. Some of these reductions in the escalation rate of revenue requirements have been due to weather-induced short-term, year-to-year O&M cost reductions and deferrals, which cannot be expected to continue. However, operating under a properly-designed margin cap mechanism, I believe that Wisconsin Gas should be able to keep its increases in revenue requirements per unit of sale to less than the rate of inflation.

For these reasons, I have concluded that, prospectively, a 0.5 percent per year offset for productivity, as applied to the GNPPI, is an ambitious although reasonable goal for the PARM.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

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SUMMARY

An economic consultant to the public utility industry with a diverse background in public utility regulation, financial analysis, and the application of mathematical models, databases and statistical analyses. Focus on the role of competition in regulated industries as a consultant and as Chairman of the Massachusetts Department of Public Utilities. Consulting experience include cost-of-service, rate design, gas supply planning, energy market analysis and policy assessment.

PROFESSIONAL EMPLOYMENT

1992-present	Reed Consulting Group Executive Vice President
1991-1992	Massachusetts Department of Public Utilities Chairman
1988-1991	Reed Consulting Group Vice President
1984-1988	R. J. Rudden Associates, Inc. Managing Consultant
1980-1984	Stone & Webster Management Consultants, Inc. Consultant

REGULATORY EXPERIENCE

As Chairman of the Massachusetts Department of Public Utilities, managed a staff of 150 people responsible for regulating all investor-owned electric, gas, telephone and water utilities. Reorganized the Department to implement a merger with the Energy Facilities

Siting Board. Computerized the consumer division complaint process and several other functions within the Department. Represented the Department in relations with the administration, legislature, press, and industry members. Accomplishments include the following:

Electric: Implemented Integrated Resource Planning Regulations; resolved contract disputes between utilities and independent power producers; modified and approved several conservation and load management program designs and cost recovery mechanisms; instituted competitive bidding practices for DSM resources; altered cost allocation standards to incorporate system design factors; approved several economic development rate proposals; ordered a management audit of one of the Commonwealth's largest utilities.

Gas: Conducted round table discussions with LDCs and other affected parties to develop regulatory response to Order 636; established and applied standards for Order 636 replacement contracts; revised standards for the acquisition of incremental supplies to serve new markets; approved several conservation and load management programs; approved alternative firm service contract arrangements.

Telecommunications: Issued nationally recognized ISDN pricing and implementation order; established standards for deregulating certain services and approved an alternative form of regulation for AT&T; approved collocation request establishing standards for competition at the local level; established terms and conditions under which cable companies can have access to telephone company facilities.

Water: Instituted preapproval mechanism for investments required to meet the Safe Drinking Water Act to allow investments to be financed by private utilities with relatively weak balance sheets.

Environment: Participated in Massachusetts inter-agency Clean Air Act Compliance task force; participated in discussions for the development of a regional NO_x allowance trading market; addressed national conferences on the interrelationship between CAA compliance and electric utility planning processes.

National/Regional: Served on the National Association of Regulatory Utility Commissioners (NARUC) Committee on Electricity; served as President of the New England Conference of Public Utility Commissioners; served as Co-Chair of the New England Governors' Conference Power Planning Committee. Active in negotiations to develop a regional transmission agreement for New England. Active in negotiations to develop a regulatory review process for Registered Holding

Companies as part of the Energy Policy Act of 1992.

CONSULTING ASSIGNMENTS

RATE AND REGULATORY ANALYSIS

Provided regulatory and energy policy advisory services to several electric and gas utilities and to large industries to address current and future trends in regulation at the state and federal level.

Provided expert testimony in several state and federal regulatory proceedings on cost of service, cost allocation, rate design, and related issues.

Participated in Commissioner Terzic's FERC task force on pipeline competition on behalf of the LDC organizations, AGD and UDC.

Directed the development of a gas resource portfolio optimization model using advanced mathematical programming techniques to support gas IRP filings.

Performed cost-of-service analyses in several electric cases. Testified in the State of Utah on the impact of the proposed merger between UP&L and PP&L on interruptible customers.

Advising a large midwestern electric utility in the evaluation of responses to RFPs for both supply-side and demand-side resources.

Managed the design of an RFP for complementary DSM resources for a large southwestern electric utility. Advised client of regulatory issues and reviewed objectives and process with state regulators.

Prepared a confidential study for a large gas supply aggregator seeking to identify potential joint venture parties and/or merger candidates.

Directing the analytical and regulatory efforts of a large LDC that is reevaluating its portfolio in response to Order 636 and evaluating major investments in incremental supplies.

Prepared testimony before the FERC on the appropriateness of market-based rates for an electric utility seeking to purchase electricity from an affiliate.

Prepared testimony and strategy on rate design issues for a large pipeline project in successful certificate proceedings before the FERC.

Acted as an intermediary on behalf of several large industrial customers in negotiations between Northeast Utilities and the New Hampshire Electric Cooperative to resolve disputes arising from the bankruptcy of PSNH and subsequent merger with Northeast Utilities.

Designed and developed a load research database application for an LDC located in the Northeast to process, summarize and report daily load data from approximately 300 remote metering devices.

Developed PC-based cost-of-service model for client distribution capable of performing functionalization, classification, and allocation as well as unit cost analysis.

ENERGY STUDIES

Performed a leading role in major energy policy project and report for the New England Governors' Conference. Responsible for developing scenarios on New England electricity demand with the energy directors of the six New England states and running these scenarios using the NEPOOL load forecasting model.

Participated in a strategic planning study for a major electric utility seeking to assess the market opportunities and threats provided by an evolving natural gas market.

Provided research and writing support for a major review of nuclear prudence cases which was distributed on a national basis to utilities, commissions and other interested parties.

Participated in the preparation of confidential report for an LDC to assist in its decision to convert some of its pipeline sales obligation to firm transportation and in a second report assessing its gas supply planning process.

Participated in a study to evaluate the economic impact of a proposal to shut-down a nuclear power plant located in the Northeast.

Developed a gas contract database and optimization model for an interstate pipeline seeking to minimize its purchase gas costs subject to contractual and operational constraints.

Developed gas price planning models to forecast prices paid by New England and New York gas distribution companies to their pipeline suppliers.

Developed energy demand forecasts for two electric utilities and one gas LDC and assisted in the preparation of testimony and cross-examination in the regulatory proceedings.

Developed a planning model to assess the competitive position of alternative fuels in the residential energy market. Based on a discounted cash flow methodology, this planning tool analyzes alternative fuel price and capital cost scenarios.

Performed state-of-the-art econometric conditional demand estimation in conjunction with the Massachusetts Institute of Technology.

ECONOMIC STUDIES

Performed econometric research for a large combination utility seeking to provide a defense of its capital structure in a rate proceeding.

Acted as the liaison between consulting engineers and operations research professionals in the development of an energy optimization model funded by the World Bank.

Developed regional econometric models for Nova Scotia and Aroostock County, Maine which provide long-run forecasts of regional production, employment and income.

Evaluated the adaptability of NEPOOL Load Forecasting Model to a New England utility's service area.

PRESENTATIONS

"Utility Kickers for NUG Purchases", The 3rd Annual Northeast Power Market Conference, May, 1993.

"Environmental Externalities: A Utility Regulator's Perspective", The 104th Annual Convention and Regulatory Symposium National Association of Regulatory Utility Commissioners, Los Angeles, California, November, 1992.

"Regulatory Issues in Energy Trade", The US-Canada Energy Outlook Conference, November, 1992.

"Structuring an Effective Wheeling Plan for New England", Retailing Wheeling and Transmission Access: The New Challenge for the Energy Industry, Arlington, VA, October, 1992.

"Will the Massachusetts Approach to ISDN Stimulate Market Demand", KMB Video Journal, August, 1992.

"The Role of Regional Planning, Forum on New England's Energy Future", May, 1992.

"The Clean Air Act and Utility Regulation: The Challenge of the 1990's", The Clean Air Marketplace Conference, April, 1992.

"Forecasts of Energy Demand in New England and Eastern Canada: Review and Commentary", presented at the Energy Security and Energy Trade Roundtable of the Northeast International Committee on Energy of the Conference of New England Governors and Eastern Canadian Premiers, April, 1988.

"Electric Demand and Capacity in New England: The Role of the New England Governors", Springfield, MA, Chamber of Commerce, June, 1987.

"Forecasting Energy Needs and Supplies" New England Conference of Public Utility Commissioners, Laconia, New Hampshire, September, 1986.

EDUCATION

AB.D. in Economics at Boston College. All course work completed for Ph.D degree with comprehensive written exams in Econometrics, Monetary Theory and International Trade.

B.A., 1976, Georgetown University.

Atlanta Gas Light Company
Derivation of Constant Return Revenue Requirements/Therm

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Operations Expense	48,591	52,364	58,772	65,180	75,406	83,923	96,541	104,627	114,047	122,364	134,331	145,635	159,200	165,200	170,700
Maintenance Expense	8,455	9,017	10,474	12,011	14,671	15,012	16,358	17,993	21,329	22,409	24,047	25,286	28,100	28,600	29,500
Depreciation & Amortization	14,793	15,725	16,755	17,988	19,420	20,996	22,248	24,870	28,068	31,207	36,099	43,150	46,300	50,200	54,900
Taxes Other Than Income Taxes	6,384	6,725	6,630	7,353	8,210	9,332	9,126	9,930	10,456	11,516	12,480	16,423	18,500	19,200	23,200
Net Plant	319,523	334,911	352,466	377,162	403,900	437,500	492,300	560,600	652,100	757,700	845,500	961,700	1,033,100	1,123,400	1,201,500
Pre–Tax Rate of Return @ 14.87%	47,513	49,801	52,412	56,084	60,060	65,056	73,205	83,361	96,967	112,670	125,726	143,005	153,622	167,050	178,663
Total Revenue Requirement	125,736	133,632	145,043	158,616	177,767	194,319	217,478	240,781	270,867	300,166	332,683	373,499	405,722	430,250	456,963
Sales (000 Therms)	2,199,893	2,243,933	2,312,991	2,322,472	2,252,539	2,201,022	2,328,303	2,201,673	2,199,831	2,353,673	2,478,317	2,560,945	2,557,400	2,540,000	2,696,100
Revenue Requirement/Therm	$0.057	$0.060	$0.063	$0.068	$0.079	$0.088	$0.093	$0.109	$0.123	$0.128	$0.134	$0.146	$0.159	$0.169	$0.169

Bay State Gas Company
Derivation of Constant Return Revenue Requirements/MMMBtu

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Operations Expense	27,898	32,169	34,849	36,927	39,471	38,936	39,761	42,775	45,659	48,912	50,162	55,782	64,663	66,568	68,911
Maintenance Expense	4,374	4,930	5,830	6,507	6,400	5,329	6,686	7,816	7,637	7,462	8,991	8,434	9,861	9,036	8,461
Depreciation & Amortization	4,447	5,236	5,697	6,175	6910	7662	8409	8853	9274	10,130	11,173	11,889	12,695	14,257	16,316
Taxes Other Than Income Taxes	7,781	7,753	8,177	8,216	6857	7114	7056	6067	6575	5,405	7,190	6,386	6,714	7,371	8,988
Net Plant	130,616	160,999	170,942	176,849	182,226	191,499	200,157	213,033	222,198	240,290	266,785	287,980	322,027	361,524	410,418
Pre-Tax Rate of Return @ 14.87%	19,423	23,941	25,419	26,297	27,097	28,476	29,763	31,678	33,041	35,731	39,671	42,823	47,885	53,759	61,029
Total Revenue Requirement	63,923	74,029	79,972	84,122	86,735	87,517	91,675	97,189	102,186	107,640	117,187	125,314	141,818	150,991	163,705
Sales (MMMBtu)	36,259	38,592	40,871	43,068	44,845	43,231	49,182	48,982	46,322	54,652	54,310	57,788	60,053	58,510	62,560
Revenue Requirement/MMMBtu	$1.763	$1.918	$1.957	$1.953	$1.934	$2.024	$1.864	$1.984	$2.206	$1.970	$2.158	$2.169	$2.362	$2.581	$2.617

Brooklyn Union Gas Company
Derivation of Constant Return Revenue Requirements/MMcf

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Oper. & Maint. Expense	114,557	125,403	133,639	165,450	189,940	205,118	229,874	244,164	262,483	270,668	282,368	305,174	299,611	316,141	333,984
Depreciation & Amortization	15,585	14,369	15,659	18,231	20,098	22,867	25,868	22,946	24,389	25,260	26,990	28,845	29,084	34,042	54,233
Taxes Other Than Income Taxes	56,817	62,937	71,819	81,244	93,294	103,642	116,163	117,503	119,023	116,421	107,410	121,577	126,928	136,419	135,549
Net Plant	440,414	457,917	487,051	514,897	541,974	578,672	614,254	651,235	684,148	731,725	809,446	877,743	940,116	1,008,812	1,060,645
Pre–Tax Rate of Return @ 14.87%	65,490	68,092	72,424	76,565	80,592	86,049	91,340	96,839	101,733	108,808	120,365	130,520	139,795	150,010	157,718
Total Revenue Requirement	252,449	270,801	293,541	341,490	383,924	417,676	463,245	481,452	507,628	521,157	537,133	586,116	595,418	636,612	681,484
Sales (MMcf)															
Firm Sales	89,810	85,878	85,692	94,235	104,884	96,879	105,199	98,058	101,111	104,104	109,593	112,465	114,300	108,694	122,476
Interr. Sales	4,622	12,328	15,674	16,134	12,248	12,479	12,270	14,797	15,148	14,943	6,674	4,707	3,706	6,379	8,577
Total Sales	94,432	98,206	101,366	110,369	117,132	109,358	117,469	112,855	116,259	119,047	116,267	117,172	118,006	115,073	131,053
Revenue Requirement/MMcf	$2.673	$2.757	$2.896	$3.094	$3.278	$3.819	$3.944	$4.266	$4.366	$4.378	$4.620	$5.002	$5.046	$5.532	$5.200

Indiana Gas Company
Derivation of Constant Return Revenue Requirements/MDTH

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987 [1]	1988	1989	1990	1991	1992
Operations Expense	22,537	24,258	25,316	29,319	32,897	35,448	41,784	40,220	45,795	56,151	62,511	65,651	73,246	70,643	70,866
Maintenance Expense	5,820	5,992	6,610	7,538	8,609	8,805	8,733	9,081	10,397	–	–	–	–	–	–
Depreciation & Amortization	7,035	7,761	8,367	9,046	9,780	12,674	13,548	14,558	15,860	17,318	19,177	20,682	22,243	23,568	25,136
Taxes Other Than Income Taxes	5,872	6,262	5,441	6,861	7,369	8,798	9,529	8,990	9,082	8,644	9,494	8,855	9,646	11,391	12,312
Net Plant															
Pre–Tax Rate of Return	178,560	186,397	198,437	213,408	232,732	241,180	251,337	268,873	288,478	303,536	319,644	336,714	391,313	417,862	476,635
@ 14.87%	26,552	27,717	29,508	31,734	34,607	35,863	37,374	39,981	42,897	45,136	47,531	50,069	58,188	62,136	70,876
Total Revenue Requirement	67,817	71,990	75,242	84,498	93,262	101,588	110,968	112,830	124,031	127,249	138,713	145,257	163,323	167,738	179,190
Sales (MDTH)	93,980	96,700	91,225	90,511	90,110	74,991	86,948	80,296	77,982	76,533	82,343	86,805	90,219	97,503	101,985
Revenue Requirement/MDTH	$0.722	$0.744	$0.825	$0.934	$1.035	$1.355	$1.276	$1.405	$1.591	$1.663	$1.685	$1.673	$1.810	$1.720	$1.757

1 *Maintenance expense was combined with operations expense in the Annual Report to Stockholders beginning in 1987.*

Northwest Natural Gas Company
Derivation of Constant Return Revenue Requirements/Therm

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Oper. & Maint. Expense	19,648	25,816	31,025	34,519	39,111	42,352	49,988	50,484	47,499	49,163	48,619	53,557	64,746	65,529	62,249
Depreciation & Amortization	9,500	9,698	10,698	11,210	12,006	13,818	15,107	17,523	18,979	20,040	23,336	23,193	27,967	33,623	33,035
Taxes Other Than Income Taxes	9,364	10,507	11,874	12,787	14,098	15,151	17,232	18,780	17,286	18,315	19,700	19,108	21,288	21,104	20,865
Net Plant	223,908	242,630	262,746	283,751	298,718	307,265	327,890	338,535	355,703	372,258	419,566	459,436	485,260	514,904	545,889
Pre–Tax Rate of Return @ 14.87%	33,295	36,079	39,070	42,194	44,419	45,690	48,757	50,340	52,893	55,355	62,389	68,318	72,158	76,566	81,174
Total Revenue Requirement	71,807	82,100	92,667	100,710	109,634	117,011	131,084	137,127	136,657	142,873	154,044	164,176	186,159	196,822	197,323
Sales (000 Therms)	833,819	901,150	745,062	767,285	652,829	641,721	755,804	784,633	672,474	734,294	798,773	1,001,527	1,009,731	1,075,381	1,065,343
Revenue Requirement/Therm	$0.086	$0.091	$0.124	$0.131	$0.168	$0.182	$0.173	$0.175	$0.203	$0.195	$0.193	$0.164	$0.184	$0.183	$0.185

Piedmont Natural Gas Company
Derivation of Constant Return Revenue Requirements/DTH

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Operations Expense	12,547	14,736	18,991	22,756	26,714	27,705	29,866	39,444	49,150	53,983	57,267	62,192	65,477	70,114	79,295
Maintenance Expense	2,513	2,689	3,656	4,364	4,665	4,139	5,124	6,315	7,681	8,069	8,945	10,084	11,641	13,059	13,326
Depreciation & Amortization	4,346	4,623	5,203	5,705	6,215	6,691	7,166	8,427	10,633	11,674	13,078	14,928	15,794	18,042	20,050
Taxes Other Than Income Taxes	7,401	9,809	13,121	17,359	18,562	19,382	21,667	16,738	15,792	16,665	16,388	17,516	17,934	19,198	21,049
Net Plant	116,236	123,035	134,965	152,022	164,723	173,117	185,500	254,935	285,156	323,804	385,769	433,650	488,210	537,874	592,773
Pre–Tax Rate of Return @ 14.87%	17,284	18,295	20,069	22,606	24,494	25,742	27,584	37,909	42,403	48,150	57,364	64,484	72,597	79,982	88,145
Total Revenue Requirement	44,091	50,152	61,040	72,790	80,651	83,660	91,407	108,833	125,659	138,541	153,042	169,204	183,443	200,395	221,865
Sales (000 DTH)	40,790	54,299	65,073	68,314	66,535	64,801	70,068	76,421	90,522	98,453	99,545	103,782	103,350	104,863	115,066
Revenue Requirement/DTH	$1.081	$0.924	$0.938	$1.066	$1.212	$1.291	$1.305	$1.424	$1.388	$1.407	$1.537	$1.630	$1.775	$1.911	$1.928

Washington Gas Light Company
Derivation of Constant Return Revenue Requirements/Therm

(Thousands of Dollars)	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Operations Expense	58,402	67,129	72,990	86,555	96,607	100,893	106,939	112,101	113,962	116,843	123,561	132,209	131,599	136,074	148,694
Maintenance Expense	20,072	20,910	22,651	24,944	24,305	24,865	26,992	27,405	28,575	30,358	29,392	31,382	32,282	30,940	31,369
Depreciation & Amortization	16,378	15,960	17,293	18,944	20,841	27,016	25,922	24,166	27,928	30,634	28,623	30,413	35,510	36,115	37,202
Taxes Other Than Income Taxes	23,998	25,179	26,264	31,012	36,877	41,767	50,936	49,005	46,612	43,335	44,726	46,822	47,131	48,490	62,546
Net Plant	360,684	376,454	410,941	462,849	491,121	495,421	510,471	534,645	553,911	600,227	648,541	729,027	783,320	821,100	864,506
Pre–Tax Rate of Return @ 14.87%	53,634	55,979	61,107	68,826	73,030	73,669	75,907	79,502	82,367	89,254	96,438	108,406	116,480	122,098	128,552
Total Revenue Requirement	172,484	185,157	200,305	230,281	251,660	268,210	286,696	292,179	299,444	310,424	322,740	349,232	363,002	373,717	408,363
Sales (000 Therms)	1,118,740	1,154,205	1,101,642	1,122,838	1,187,757	1,073,344	1,199,459	1,090,018	1,121,640	1,230,876	1,249,852	1,334,459	1,304,853	1,263,307	1,352,799
Revenue Requirement/Therm	$0.154	$0.160	$0.182	$0.205	$0.212	$0.250	$0.239	$0.268	$0.267	$0.252	$0.258	$0.262	$0.278	$0.296	$0.302

Comparable LDCs: Compound Annual Growth Rate (CAGR) in Constant Return Revenue Requirements
1978-1992

Revenue Requirements/Unit of Sales

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Atlanta	$0.057	$0.060	$0.063	$0.068	$0.079	$0.088	$0.093	$0.109	$0.123	$0.128	$0.134	$0.146	$0.159	$0.169	$0.169
Bay State	$1.763	$1.918	$1.957	$1.953	$1.934	$2.024	$1.864	$1.984	$2.206	$1.970	$2.158	$2.169	$2.362	$2.581	$2.617
Brooklyn	$2.673	$2.757	$2.896	$3.094	$3.278	$3.819	$3.944	$4.266	$4.366	$4.378	$4.620	$5.002	$5.046	$5.532	$5.200
Indiana	$0.722	$0.744	$0.825	$0.934	$1.035	$1.355	$1.276	$1.405	$1.591	$1.663	$1.685	$1.673	$1.810	$1.720	$1.757
Northwest	$0.086	$0.091	$0.124	$0.131	$0.168	$0.182	$0.173	$0.175	$0.203	$0.195	$0.193	$0.164	$0.184	$0.183	$0.185
Piedmont	$1.081	$0.924	$0.938	$1.066	$1.212	$1.291	$1.305	$1.424	$1.388	$1.407	$1.537	$1.630	$1.775	$1.911	$1.928
Washington	$0.154	$0.160	$0.182	$0.205	$0.212	$0.250	$0.239	$0.268	$0.267	$0.252	$0.258	$0.262	$0.278	$0.296	$0.302

Revenue Requirements/Unit of Sales -- CAGR (%)

	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92
Atlanta	8.0738%	8.3782%	8.6389%	8.6141%	7.9435%	7.5159%	7.7324%	6.4590%	5.4702%	5.8537%	6.0029%	5.1361%	3.3612%	0.0595%
Bay State	2.8613%	2.4175%	2.4519%	2.6943%	3.0691%	2.8929%	4.3314%	4.0326%	2.8870%	5.8472%	4.9401%	6.4637%	5.2650%	1.4018%
Brooklyn	4.8672%	5.0007%	4.9992%	4.8330%	4.7235%	3.4883%	3.5178%	2.8685%	2.9552%	3.5027%	3.0021%	1.3016%	1.5185%	-6.0045%
Indiana	6.5628%	6.8284%	6.5048%	5.9172%	5.4349%	2.9317%	4.0770%	3.2437%	1.6733%	1.1100%	1.0582%	1.6392%	-1.4825%	2.1322%
Northwest	5.6225%	5.6095%	3.3743%	3.1805%	0.9843%	0.1743%	0.8250%	0.8334%	-1.5335%	-0.9803%	-1.0043%	4.1550%	0.2315%	1.1989%
Piedmont	4.2205%	5.8250%	6.1885%	5.5398%	4.7510%	4.5577%	5.0052%	4.4238%	5.6292%	6.5023%	5.8249%	5.7511%	4.2260%	0.8970%
Washington	4.9162%	4.9832%	4.3150%	3.5765%	3.6031%	2.1221%	2.9608%	1.7118%	2.0685%	3.6608%	3.9812%	4.8740%	4.1677%	2.0422%

Weights
Company Revenue Requirements as a Percentage of Total Revenue Requirements

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Total
Atlanta	15.75%	15.40%	15.30%	14.79%	15.02%	15.30%	15.62%	16.38%	17.29%	18.21%	18.95%	19.53%	19.90%	19.95%	19.79%	17.70%
Bay State	8.01%	8.53%	8.44%	7.84%	7.33%	6.89%	6.58%	6.61%	6.52%	6.53%	6.68%	6.55%	6.96%	7.00%	7.09%	7.03%
Brooklyn	31.62%	31.20%	30.97%	31.84%	32.44%	32.89%	33.27%	32.74%	32.41%	31.62%	30.60%	30.64%	29.20%	29.52%	29.52%	31.13%
Indiana	8.50%	8.30%	7.94%	7.88%	7.88%	8.00%	7.97%	7.67%	7.92%	7.72%	7.90%	7.59%	8.01%	7.78%	7.76%	7.88%
Northwest	8.99%	9.46%	9.78%	9.39%	9.26%	9.21%	9.41%	9.33%	8.72%	8.67%	8.77%	8.58%	9.13%	9.13%	8.55%	9.02%
Piedmont	5.52%	5.78%	6.44%	6.79%	6.81%	6.59%	6.56%	7.40%	8.02%	8.41%	8.72%	8.85%	9.00%	9.29%	9.61%	7.97%
Washington	21.61%	21.33%	21.13%	21.47%	21.26%	21.12%	20.59%	19.87%	19.12%	18.84%	18.38%	18.26%	17.80%	17.33%	17.69%	19.27%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Weighted Average CAGR in Revenue Requirements

	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92
Atlanta	1.2717%	1.2901%	1.3220%	1.2740%	1.1930%	1.1500%	1.2076%	1.0577%	0.9459%	1.0662%	1.1376%	1.0029%	0.6689%	0.0119%
Bay State	0.2291%	0.2062%	0.2069%	0.2113%	0.2249%	0.1994%	0.2851%	0.2665%	0.1883%	0.3819%	0.3298%	0.4235%	0.3662%	0.0981%
Brooklyn	1.5392%	1.5604%	1.5483%	1.5388%	1.5321%	1.1472%	1.1702%	0.9392%	0.9577%	1.1077%	0.9185%	0.3988%	0.4435%	-1.7725%
Indiana	0.5575%	0.5664%	0.5164%	0.4662%	0.4282%	0.2345%	0.3249%	0.2489%	0.1325%	0.0857%	0.0836%	0.1245%	-0.1188%	0.1658%
Northwest	0.5057%	0.5307%	0.3299%	0.2987%	0.0912%	0.0161%	0.0777%	0.0777%	-0.1338%	-0.0850%	-0.0881%	0.3566%	0.0211%	0.1094%
Piedmont	0.2331%	0.3366%	0.3985%	0.3760%	0.3237%	0.3002%	0.3285%	0.3274%	0.4516%	0.5466%	0.5078%	0.5087%	0.3802%	0.0834%
Washington	1.0622%	1.0632%	0.9119%	0.7679%	0.7661%	0.4482%	0.6096%	0.3401%	0.3954%	0.6895%	0.7319%	0.8899%	0.7420%	0.3539%
Weighted Average CAGR	5.3985%	5.5535%	5.2339%	4.9329%	4.5592%	3.4956%	4.0036%	3.2576%	2.9376%	3.7926%	3.6211%	3.7049%	2.5031%	-0.9500%

	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92
Simple Average CAGR	5.3035%	5.5775%	5.2104%	4.9079%	4.3585%	3.3833%	4.0642%	3.3675%	2.7357%	3.6423%	3.4007%	4.1887%	2.4696%	0.2467%

Source: [illegible]l Reports to Stockholders for 7 Comparable Companies; Department of Commerce Business Statisti[illegible] S. Bureau of Labor Statistics

Comparable LDCs: Productivity (Growth Rate Differentials)

CAGR in Constant Return Revenue Requirements	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92
Weighted Average CAGR	5.3985%	5.5535%	5.2339%	4.9329%	4.5592%	3.4956%	4.0036%	3.2576%	2.9376%	3.7926%	3.6211%	3.7049%	2.5031%	-0.9500%
Simple Average CAGR	5.3035%	5.5775%	5.2104%	4.9079%	4.3585%	3.3833%	4.0642%	3.3675%	2.7357%	3.6423%	3.4007%	4.1887%	2.4696%	0.2467%

Gross National Product Fixed-Weight Price Index:	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92
CAGR	4.9654%	4.7064%	4.3353%	3.8961%	3.6616%	3.6361%	3.6650%	3.6868%	3.8247%	3.9717%	3.9897%	3.8442%	3.6012%	3.3163%

Consumer Price Index - U.S. City Average:	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92
CAGR	5.6263%	5.1984%	4.5348%	4.0245%	3.8133%	3.8803%	3.8258%	3.8637%	4.2016%	4.3124%	4.3562%	4.2026%	3.6075%	3.0103%

	78-92	79-92	80-92	81-92	82-92	83-92	84-92	85-92	86-92	87-92	88-92	89-92	90-92	91-92	Mean of Intervals
GNPPI Less Comparable LDC (Weighted Average) Revenue Requirement Escalation =	-0.4331%	-0.8471%	-0.8986%	-1.0368%	-0.8976%	0.1406%	-0.3386%	0.4292%	0.8872%	0.1791%	0.3686%	0.1393%	1.0981%	4.2663%	-0.0931%
CPI-U Less Comparable LDC (Weighted Average) Revenue Requirement Escalation =	0.2278%	-0.3551%	-0.6991%	-0.9083%	-0.7459%	0.3847%	-0.1778%	0.6060%	1.2641%	0.5198%	0.7351%	0.4977%	1.1043%	3.9603%	0.1887%
GNPPI Less Comparable LDC (Simple Average) Revenue Requirement Escalation =	-0.3381%	-0.8711%	-0.8750%	-1.0118%	-0.6969%	0.2529%	-0.3992%	0.3193%	1.0890%	0.3294%	0.5889%	-0.3445%	1.1316%	3.0696%	-0.0635%
CPI-U Less Comparable LDC (Simple Average) Revenue Requirement Escalation =	0.3228%	-0.3790%	-0.6756%	-0.8834%	-0.5452%	0.4970%	-0.2384%	0.4961%	1.4659%	0.6700%	0.9555%	0.0140%	1.1378%	2.7635%	0.2183%

1 *Excludes 1991-1992 Interval*

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Gas Company, As a Gas Public Utility, to Implement a Productivity-based Alternative Ratemaking Mechanism Pilot	))))	Docket 6650-GR-112

REBUTTAL TESTIMONY OF ROBERT C. YARDLEY, JR.

Q. Please state your name, affiliation, and business address.

A. My name is Robert C. Yardley, Jr.. I am Executive Vice President and a Director of Reed Consulting Group, 1050 Waltham Street, Lexington, Massachusetts 02173.

Q. On whose behalf are you submitting this testimony?

A. I am testifying on behalf of Wisconsin Gas Company ("Wisconsin Gas" or "the Company").

Q. Are you the same Robert C. Yardley, Jr. who previously submitted Prepared Direct Testimony on behalf of Wisconsin Gas Company?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony of James J. Wottreng, representing the Public Service Commission of Wisconsin ('PSCW'). I will address Mr. Wottreng's testimony concerning the appropriate inflation factor to be used in the margin cap formula that is a key element in the Company's Productivity-based Alternative Ratemaking Mechanism ('PARM') Pilot. I will also comment on Mr. Wottreng's testimony regarding the appropriate inflation time frame and productivity factor to be utilized in the PARM.

Q. What is your response to Mr. Wottreng's conclusion that the Consumers Price Index for Urban Consumers ("CPI-U") is the appropriate inflation factor to be used in the margin cap formula ?

A. Mr. Wottreng recognizes the importance of using a constant weight price index in order to measure pure price changes from one period to the next. I agree with Mr. Wottreng that both the CPI-U and the Gross National Product Fixed-Weighted Price Index ('GNPPI') meet the fixed weight criterion.

I believe, however, for the reasons that I cited in my Prepared Direct Testimony, that the GNPPI is a more appropriate inflation factor to be used in establishing the margin cap. The CPI-U indexes the prices of consumer goods, while the GNPPI includes both industrial and consumer goods. As I stated in my Prepared Direct Testimony, the inclusion of both industrial and consumer goods in the GNPPI makes it more representative of the price changes that relate to the Company's labor and materials costs than the CPI-U.

Mr. Wottreng also points out the importance of public understanding and acceptance of the inflation factor. I agree that this is an important consideration for choosing the appropriate inflation index. While I concede that the general public is more likely to be familiar with the

CPI-U, I also believe that the public would readily accept a Commission finding that the GNPPI is a more appropriate measure of inflation to be used in establishing the margin cap.

Mr. Wottreng also states that the Commission has, and continues to use, the CPI-U as its measure of inflation in forecasting expenses for future test years. In my view, the Commission should give less weight to the "consistency" criterion and should decide this issue based on the relative merits of the two indices in achieving the objectives of the margin cap.

Q. Please address Mr. Wottreng's comments regarding the appropriate inflation time frame for the margin cap calculation.

A. Mr. Wottreng and I agree that an historical measure of inflation should be used rather than a forecasted value. We have a slight difference of opinion, however, regarding the time period to be used to calculate the annual inflation rate. Mr. Wottreng proposes using the change in the annual inflation index (i.e., the value for the most recent annual period relative to the value for the prior annual period). The Company proposes that the annual inflation factor be calculated by the annual change in the GNPPI measured using the most recent quarter's value compared the value in the same quarter in the prior year. As Mr. Wottreng points out, his proposal is likely to be more stable while the Company's method is based on more current information. The Commission must make the final judgment regarding the relative merits of these two methods. I believe that the Company proposal should be adopted because it represents a rate of inflation for the most recent annual period. More importantly, whichever method is chosen must be applied consistently during the period in which the PARM is in effect.

Q. Do you have any comments regarding Mr. Wottreng's discussion of the appropriate productivity factor to be included in the margin cap formula?

A. Yes. I have three brief comments. First, Mr. Wottreng indicates that "disastrous results may ensue" if the productivity factor is set too high (see page 10, lines 20-23). As the Commission has recognized in its recent rate decisions, this would only occur if Wisconsin Gas accepted an "offer" in the Commission order in this proceeding that yielded a result it mistakenly believed that it could achieve. Thus, if the Commission reduces the margin base and/or sets a productivity factor which, when combined, exceed the Company's ability to reduce costs, disastrous results would occur if the Company accepted these terms and could not deliver the cost savings. For example, the Company has indicated in its Supplemental Team testimony that it believes that it could accept a productivity factor of 3.0%, applied to the margin base allowed in its most recent rate order as part of its proposed PARM. If the Commission revises the PARM productivity factor or margin base beyond what the Company has agreed to, the Company will need to revisit its ability to meet this aggressive target.

Second, while Mr. Wottreng's methodology is similar to mine, it differs substantially in one critical respect. Mr. Wottreng's quantitative analysis is based solely on Wisconsin Gas data, whereas I relied on data from the comparative group of LDCs that has been selected by the PSCW staff as comparable to Wisconsin Gas. In theory, both the annual price change and the productivity component of the margin cap, should reflect cost movements for the industry and not for an individual firm. The purpose of a margin cap is to set an industry benchmark against which an individual utility's performance will be measured.

Third, I note that Mr. Wottreng's calculation of a 3.6 % productivity for Wisconsin Gas is derived by selecting the highest value from among the periods examined. In contrast, my recommendation is based on an average of all of the periods that I examined and is therefore less subject to a claim of bias. Given the fact that the productivity factor will be sustained for a three-year period, basing it on the single highest experienced value is particularly perverse.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Gas Company, as a Gas Public Utility, to Implement a Productivity-based Alternative Ratemaking Mechanism Pilot	))))	Docket No. 6650-GR-112

APPLICATION

1. Applicant, Wisconsin Gas Company, a corporation organized and existing under and by virtue of the laws of the State of Wisconsin (hereinafter referred to as "Company"), has its principal office and place of business at 626 East Wisconsin Avenue, Milwaukee, Wisconsin, is a "public utility" within the meaning of Section 196.01, Wisconsin Statutes, and is engaged in the business of selling and distributing natural gas to more than 470,000 customers in 446 communities in the State of Wisconsin.

2. The Company's last general rate order was dated October 29, 1992 in Docket No. 6650-GR-110, based on a test year running from November 1, 1992 to October 31, 1993. The Company has filed an Application for Rate Relief, Docket No. 6650-GR-111, based upon a projected test year from November 1, 1993 through October 31, 1994. Technical hearings for that Docket are scheduled for the week of August 23, 1993. It is anticipated that the order in Docket No. 6650-GR-111 will be issued prior to the commencement of hearings in this Docket.

3. The Company, in this Application, is proposing a pilot Productivity-based Alternative Ratemaking Mechanism ("PARM") to become effective on November 1, 1994, the expiration of the test year upon which Docket No. 6650-GR-111 is based. The PARM is a pilot ratemaking tool that reduces, in real dollar terms, the controllable costs that are recovered in rates from the Company's customers and recognizes the effects of the increasingly competitive natural gas market.

4. The Company is proposing the PARM concept as an extension of the Commission's

recently adopted biennial rate case process. In addition to the margin cap, the pilot also proposes a weather adjustment mechanism to take effect beginning with the 1994-95 heating season.

5. Under the PARM, the margin component of the Company's rates would be capped for the four-year period November 1, 1993 (the anticipated effective date of the order for the pending Docket No. 6650-GR-111) through October 31, 1997. The cap would be adjusted annually on November 1, 1994, November 1, 1995 and November 1, 1996 by an inflation factor less a productivity improvement factor, commonly known as a CPI-x factor. The other key feature of the PARM, the weather adjustment mechanism, is essential because it allows management to focus on long term productivity gains rather than responding to significant weather variations, over which management has no control. Each month, from October through May, customer bills would be adjusted to reflect differences between normal and actual degree days during the billing period. This will stabilize the cash payments of customers (for example, bills are reduced in colder-than-normal weather), reduce revenue volatility for the Company and mitigate short-term weather related gain or loss for shareholders.

WHEREFORE, the Company respectfully requests that the Commission proceed promptly to investigate and hold hearings, as necessary, on this Application; that it approve as reasonable and lawful the pilot mechanism proposed by the Company; and that it grants such other and further relief in the premises as may be just, reasonable and proper.

Dated this 8th day of July, 1993.

Respectfully submitted,

WISCONSIN GAS COMPANY

By ______________
Thomas F. Schrader
President and CEO

STATE OF WISCONSIN)
) ss
MILWAUKEE COUNTY)

THOMAS F. SCHRADER, being first duly sworn on oath deposes and says that he is the President of Wisconsin Gas Company, the Applicant named herein, and makes this verification for and on behalf of said corporation; that he has read the foregoing Application and knows the contents thereof; and that the statements therein contained are true of his own knowledge, except as to matters therein stated on the information and belief, and as to those matters he believes the same to be true.

Thomas F. Schrader

Subscribed and sworn to before
me this 9th day of July 1993.

Gregory A. Wheeler
Notary Public, State of Wisconsin
My Commission is Permanent.

Prepared July 1993

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Gas Company, as a Gas Public Utility, to Implement a Productivity-based Alternative Ratemaking Mechanism Pilot	))))	Docket 6650-GR-112

TESTIMONY OF THOMAS F. SCHRADER

Q. Please state your name and address.

A. My name is Thomas F. Schrader. My business address is 626 East Wisconsin Avenue, Milwaukee, Wisconsin, 53202.

Q. What is your position with Wisconsin Gas Company ("the Company")?

A. I am President and Chief Executive Officer.

Q. Would you please briefly describe your educational background and business experience?

A. I have both an undergraduate degree and graduate degree in Engineering and Applied Science from Princeton University. Prior to assuming my present responsibilities in 1988, I held several positions with the Company including positions in Market Services and Regulatory Affairs. Prior to joining the

Company in 1978, I was employed by the Environmental Protection Agency in Washington, D.C., and Public Service Electric and Gas Company in New Jersey.

Q. Have you previously testified in proceedings before the Public Service Commission of Wisconsin ("the Commission" or "PSC")?

A. Yes, on several occasions.

Q. What is the Company seeking in this proceeding?

A. The Company is seeking to extend the time frame covered by the Order in Docket 6650-GR-111 by implementing a pilot Productivity-based Alternative Ratemaking Mechanism ("PARM") to be in effect through October 31, 1997.

The two key features of the PARM are an indexed four-year cap on the margin per therm for each rate classification and a weather adjustment mechanism. The emphasis in designing the PARM has been to focus management's attention on improving long term productivity in those areas where management has a significant degree of control. The weather adjustment mechanism is an essential part of the PARM in that it allows management to focus its efforts on long term productivity gains rather than responding to large weather variations, over which management has no control.

Q. Please describe the purpose of your testimony.

A. I will summarize the objectives that guided the Company in developing this proposal and then provide an overview of the PARM. I will also discuss the approach the Company has taken in designing the PARM. Finally, I will present my own views on why I believe that this proposal is in the best interests of ratepayers and shareholders and should therefore be approved by the Commission.

Q. Why is the Company proposing a PARM?

A. The Company is proposing the Productivity-based Alternative Ratemaking Mechanism (PARM) because the national restructuring of the gas industry requires utilities such as Wisconsin Gas to operate like non-regulated businesses where success is determined by quality service, productivity improvements and sound management.

Q. What are the objectives that guided development of the PARM?

A. The primary objective that guided the Company was to develop a ratemaking mechanism that would continuously motivate improvement in the value delivered to customers.

Other objectives for the PARM are to:

- Generate long term productivity savings that can be shared by the Company's customers, employees and shareholders.

- Achieve rates that are lower and more stable for the Company's customers than rates set in biennial ratecase filings utilizing traditional rate of return regulation.

- Shift management focus from short term responses caused by weather variations to a focus that is long term and is based on increasing productivity.

- Strengthen our relationship with the Commission and our customers.

Q. What is the primary benefit of the PARM to the Company's ratepayers?

A. The primary benefit to customers is that the productivity improvements required by the PARM will keep any increases in the Company's margin to a level lower than the rate of inflation. For customers, this will mean real-dollar decreases in the margin component of rates over the next four years.

Q. How would the PARM keep rate increases below the level of inflation?

A. By setting a productivity improvement factor, the PARM establishes a minimum cost savings target for the Company that will keep rates to consumers lower than they would be if the margin recovered in rates increased at a pace at or above the rate of inflation.

The proposed productivity factor, which determines the extent to which the Company guarantees that any margin increases will be lower than inflation, will be discussed by the Company's expert witness.

Q. Please describe in more detail how the PARM would work.

A. The PARM allows for an adjustment each year to the Company's margin that recognizes inflation by using an index (e.g., CPI), but reduces this inflation adjustment by a productivity improvement factor ("x"). This "CPI-x" calculation determines the maximum margin that could be charged to ratepayers.

Q. How does the PARM balance ratepayer and shareholder interests?

A. The PARM balances ratepayer and shareholder interests by: (1) setting a productivity goal that caps the Company's allowed costs and thereby keeps rates to consumers lower than they might otherwise be, and (2) allows the Company to retain as earnings the cost savings, if any, that are greater than the targeted cost reduction. In other words, the PARM is a pilot ratemaking tool that reduces, in real dollar terms, the controllable costs that are recovered in rates from the Company's customers and recognizes the effects of the increasingly competitive natural gas market.

Q. How does the PARM affect the Company's risk of earning its allowed return?

A. By proposing the PARM, the Company commits itself to pass a targeted level of savings directly to the ratepayers, before such savings are specifically identified by the Company. The Company bears the risk of being able to achieve the necessary productivity improvements to generate the cost savings. In exchange, the Company would be allowed to retain further productivity benefits, if any, in excess of those committed to the ratepayers during the four year time frame. If the Company fails to realize the level of productivity improvements promised, the actual rates charged to the Company's customers will still be based on the targeted level of productivity gains. The result would be that, other things being equal, the Company would not earn its allowed rate of return.

Q. How does the PARM differ from a temporary rate "freeze?"

A. The PARM is a four year pilot, longer than the "freezes" proposed by other utilities. Under a PARM, the focus will be on long-term productivity savings, not on traditional rate of return regulation.

Q. How was a PARM developed at the Company?

A. Over the past several years, the Company has been reviewing and revising its strategic plan to reflect the increased rate of change resulting from the ongoing deregulation of the gas industry at the federal level. Following the Company's response to the PSC's biennial process initiative, the Company formed a task force of fourteen managers representing every division of the Company to investigate the implications of alternative ratemaking mechanisms for the Company.

The task force researched various ratemaking mechanisms in use here in Wisconsin, throughout the United States and in other countries. The task force assessed the benefits and drawbacks of these various alternative ratemaking mechanisms from a number of perspectives. After a great deal of deliberation and discussion, the task force concluded that the most appropriate mechanism for the Company at this time is an indexed cap on margin, coupled with a weather adjustment mechanism.

Q. Please summarize your testimony.

A. I believe that the Commission should approve the Company's proposal to institute a four-year PARM pilot for the following reasons:

(1) It will benefit ratepayers in both the short term and the long term by providing a more efficient, simple mechanism for the identification and implementation of productivity improvements and the allocation of these savings to ratepayers through lower rates.

(2) The PARM pilot represents a more efficient regulatory process and one that is an appropriate and beneficial step in the transition to a more competitive natural gas market.

(3) The PARM will provide appropriate incentives to the Company's management team to control costs and to prepare our organization for the competitive environment resulting from the deregulation and restructuring of the gas industry.

(4) Finally, the PARM is in the best interests of our customers, our employees, our shareholders, and the Commission.

Q. Will other witnesses testify in this proceeding?

A. In addition to my own testimony, a panel of Company witnesses, all of whom have been instrumental in designing the PARM, will discuss the details of and the reasoning behind the various aspects of the PARM. The panel consists of:

Luc P. Piessens	Manager of Planning and Development
James F. Schott	Controller
Mary L. Wolter	Manager-Rates

We have also retained Mr. Robert C. Yardley, Jr., an industry consultant, and recently Chairman of the Massachusetts Department of Public Utilities, who will submit testimony on our behalf regarding the economic rationale for the PARM, and the manner in which it provides a fundamental benefit to rate-payers.

Q. Does this conclude your testimony?

A. Yes, it does.