Rate Adjustment Indexes for Ontario's Natural Gas Utilities

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Economic and Litigation Consulting

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Staff of the Ontario Energy Board issued a report on January 5 of this year which detailed its views on a new approach to incentive regulation ("IR") for Enbridge Gas Distribution ("Enbridge") and Union Gas ("Union"). Under the plan outlined, the escalation in the rates for each utility would be limited by a summary price cap index ("PCI"). The PCI would grow each year at the pace of last year's inflation in the gross domestic product implicit price index ("GDPIPI") for final domestic demand less an X factor. The X factor would be the sum of four terms:

1. Input Price Differential (the difference between the input price trends of the economy and the gas utility industry);
2. Productivity Differential (the difference between the productivity trends of the gas utility industry and the economy);
3. Average Use Factor (to account for average use trends); and
4. Stretch Factor (to share the benefits of expected performance gains).

Pacific Economics Group ("PEG") is the advisor to Board staff on IR issues. Staff initially directed PEG to undertake input price and productivity research that would support the development of the X factor of the summary PCI. It subsequently asked for the development of a revenue cap index and of separate PCIs, if warranted, for important service groups.

We first reported on our research on March 30, 2007. Following the receipt of constructive input by interested parties, our methodology was revised. One noteworthy change was the replacement of U.S. construction cost indexes used to calculate the capital price with a Statistics Canada capital cost deflator that is much more stable. Another was the use of company-specific rather than sample mean cost elasticity estimates to calculate TFP and the service-specific PCIs. A report on the new work was issued on June 20, 2007.

In August, parties to the proceeding filed evidence that included additional thoughts about alternative methods for X factor design. The evidence also included a proposal by Enbridge for a revenue per customer cap, an incentive regulation mechanism that had not previously been considered. Stakeholders asked for an update of our research to reflect

2006 data for Enbridge and Union. The passage of time has given us the chance to reflect on our methods and some Statistics Canada indexes used in our research have been revised.

Additional research has been undertaken in reponse to these new developments. The methodology was changed, new data were employed, and a revenue per customer cap was developed. Noteworthy methodological changes include the following:

- Measures of the Enbridge and Union input price and productivity trends were upgraded to include 2006 data.
- The Enbridge and Union estimates of weather normalized volumes were used, and the PEG method for normalizing U.S. volumes was upgraded to better reflect the recent winter warming trend.
- A line miles index was added to the econometric cost model and the two throughput variables previously used as output variables in the model were consolidated into a total throughput variable.
- The addition of two business condition variables --- frost depth and earthquake risk--- to the cost model was considered.
- The debt/equity mix used to compute the rate of return was changed from 65/35 to 64/36.
- ADJs for the new Union rates M1 and M2 were developed.
- System gas was removed from the cost of Union Gas because it will be Y factored during the rate plan.
- The method for removing the effect of conservation and demand management on the volume trends of Enbridge and Union was upgraded.
- Revised Stats Canada indexes of the trends in certain input prices and the productivity of the Canadian private business sector were used in the calculations.
- Peer groups were used to set the TFP targets.

A preliminary report on the new research was filed on November 6, 2007. Subsequent to this filing, problems were discovered in the implementation of some of the methodological reforms. We have rectified these problems and present new numbers in this report. A redlined version of the report is available that highlights changes made since the release of the November 8 errata pages.

Overview of Research

The research considered the output, productivity, and input price trends of Enbridge and Union and of 36 US gas utilities for which we have gathered good data. The US results were used to establish TFP growth targets for Enbridge and Union and to provide a point of comparison for the companies' average use trends. The research included an econometric study of gas utility cost drivers that was based on the US data. The research provides the basis for recommendations for both PCIs and revenue per customer caps.

Established methods and publicly available data from respected sources were employed in the research. The sample period for the US work was 1994-2004. Due to the restructuring of Ontario's gas industry in 1998 and other special circumstances, the sample period for the Enbridge and Union indexing work was limited to 2000-2006.

We calculated input price and productivity trends for Enbridge and Union using two approaches to capital cost measurement.

- Geometric decay ("GD"): This approach has been extensively used in both scholarly cost research and in index research undertaken in support of rate and revenue cap indexes. It features replacement (current dollar) valuation of utility plant and a constant rate of depreciation.
- Cost of service ("COS"): This approach to capital costing is more novel in statistical research but better reflects the way that capital cost is calculated for purposes of ratemaking in traditional regulation. It features book (historical dollar) valuation of capital and straight line depreciation.

The COS approach involves capital price indexes that are much more stable, and this facilitates the choice of an input price differential. For these reasons, we recommend use of the COS results to set X over the alternative GD results. However, care must be taken in the choice of IPDs using either method to ensure that they are not biased by capital price volatility.

Our research has culminated in recommendations for the design of PCIs and revenue per customer caps for Enbridge and Union. We believe that these recommendations are just and reasonable and can place incentive regulation of Ontario's gas utilities on a solid foundation of economic reason and empirical research.

Key Results

The following table details our proposals for the X factors of the summary PCIs. It also provides, in italics, a notion of the likely growth in these PCIs during the IR plan. This projection requires an assumption regarding GDPIPI growth, and we use for this purpose the historical trend from 2000 to 2006. The growth in the *actual* PCI would reflect the growth in the actual GDPIPI for final domestic demand during the IR plan period.

Price Cap Index Details

	GD Capital Cost		**COS Capital Cost**	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.80	1.32	1.95	1.84
$TFP^{Economy}$ [B]	0.45	0.45	0.47	0.47
PD [C=A-B]	**1.35**	**0.87**	**1.48**	**1.37**
Input $Prices^{Economy}$ [D]	2.23	2.23	2.22	2.22
Input $Prices^{Industry}$ [E]	1.98	2.03	2.44	2.36
IPD [F=D-E]	**0.25**	**0.20**	**-0.22**	**-0.14**
$Output^{Revenue\text{-}Weighted}$ [G]	1.68	1.05	1.68	1.05
$Output^{Elasticity\text{-}Weighted}$ [H]	2.84	1.63	2.96	1.77
AU [I=G-H]	**-1.16**	**-0.58**	**-1.28**	**-0.72**
Stretch [J]	**0.50**	**0.50**	**0.50**	**0.50**
X [K=C+F+I+J]	**0.94**	**0.99**	**0.48**	**1.01**
GDPIPI FDD [L]	*1.78*	*1.78*	*1.78*	*1.78*
Notional PCI growth [L-K]	*0.84*	*0.79*	*1.30*	*0.77*

Here are some details of our recommendations for the PCIs for individual service groups. Separate PCIs have been designed for each rate class that includes residential service. The rates for other services would be subject to common but company specific PCIs. We once again provide in italics a notion of the likely trend in these indexes during the plan using the recent historical trend in the GDPIPI.[1]

[1] The actual trend in the index would depend, once again, on GDPIPI FDD growth during the plan.

Service Group PCIs

COS Capital Cost

Company	Service Group	Sum of Common Terms [A]	ADJ [B]	**Total X Factor [C]=A+B**	*Recent GDPIPI Trend [D]*	***Notional PCI Growth [D]-[C]***
Enbridge	Rate 1	0.48	-0.57	**-0.09**	*1.78*	***1.87***
	Nonresidential	0.48	1.17	**1.65**	*1.78*	***0.13***
Union	Rate M1	1.01	-0.78	**0.23**	*1.78*	***1.55***
	Rate M2	1.01	-0.46	**0.55**	*1.78*	***1.23***
	Rate 01	1.01	-0.57	**0.44**	*1.78*	***1.34***
	Rate 10	1.01	1.08	**2.09**	*1.78*	***-0.31***
	Other Services	1.01	0.88	**1.89**	*1.78*	***-0.11***

Service Group PCIs

GD Capital Cost

Company	Service Group	Sum of Common Terms [A]	ADJ [B]	**Total X Factor [C]=A+B**	*Recent GDPIPI Trend [D]*	***Notional PCI Growth [D]-[C]***
Enbridge	Rate 1	0.94	-0.55	**0.39**	*1.78*	***1.39***
	Nonresidential	0.94	1.11	**2.05**	*1.78*	***-0.27***
Union	Rate M1	0.99	-0.80	**0.19**	*1.78*	***1.59***
	Rate M2	0.99	-0.43	**0.56**	*1.78*	***1.22***
	Rate 01	0.99	-0.54	**0.45**	*1.78*	***1.33***
	Rate 10	0.99	1.00	**1.99**	*1.78*	***-0.21***
	Other Services	0.99	0.88	**1.87**	*1.78*	***-0.09***

It can be seen that PCIs for service classes involving residential customers would rise much more rapidly than those of classes that do not. They are designed to assign to these classes the responsibility for the decline in their average use.

A revenue per customer cap limits escalation in a company's revenue requirement. A balancing account commonly ensures that the allowed revenue requirement is exactly recovered. Rate design can be addressed periodically in hearings much like it is today.

Here are workable formulas for the X factor of revenue per customer caps that are supported by our research. We once again provide in italics a notion of the likely trend in revenue per customer caps during the IR period.[2] It can be seen that these grow a lot more slowly than price cap indexes since they do not provide compensation for declining average use. In fact, our research supports the idea of revenue per customer freezes.

Revenue Per Customer Cap Details

	GD Capital Cost		**COS Capital Cost**	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.80	1.32	1.95	1.84
$TFP^{Economy}$ [B]	0.45	0.45	0.47	0.47
PD [C=A-B]	**1.35**	**0.87**	**1.48**	**1.37**
Input $Prices^{Economy}$ [D]	2.23	2.23	2.22	2.22
Input $Prices^{Industry}$ [E]	1.98	2.03	2.44	2.36
IPD [F=D-E]	**0.25**	**0.20**	**-0.22**	**-0.14**
Customers [G]	3.28	2.02	3.28	2.02
$Output^{Elasticity\text{-}Weighted}$[H]	2.84	1.63	2.96	1.77
RC [I=G-H]	**0.44**	**0.39**	**0.32**	**0.25**
Stretch [J]	**0.50**	**0.50**	**0.50**	**0.50**
X [K=C+F+I+J]	**2.54**	**1.96**	**2.08**	**1.98**
GDPIPI FDD [L]	*1.78*	*1.78*	*1.78*	*1.78*
Notional RC growth [L-K]	*-0.76*	*-0.18*	*-0.30*	*-0.20*

Productivity Differential

We compared the productivity trends of Enbridge and Union (*i.e.*, company specific TFP trends) to the trends of US gas utilities in an effort to ascertain appropriate TFP targets. Under the COS approach to capital costing the annual TFP growth of Enbridge and Union

[2] The actual trend in the index would depend, once again, on actual GDPIPI FDD growth during the plan.

averaged 0.60% and 1.47% respectively. The analogous figures using GD costing were 0.62% for Enbridge and 1.66% for Union. The slow TFP growth of Enbridge was chiefly due to rapid growth in O&M expenses and was not discernably tied to its brisk customer growth.

Our research also revealed that US results are quite relevant to the selection of X factors for both Ontario utilities if used properly. Since, additionally, an external source of data is generally desirable in such an exercise, we used our results on the TFP trends of US utilities exclusively to establish the TFP targets used in X factor design. Repeated application of this practice in the development of future IR plans will help to keep performance incentives strong.

Research of two kinds was undertaken to select appropriate target rates of TFP growth for Enbridge and Union from the US results. Both research initiatives made use of our econometric estimates of the cost impact of external business conditions and the well-established mathematical theory of how these conditions affect TFP growth. One approach was to calculate the average trends in the TFP indexes of peer groups consisting of US companies facing similar conditions for TFP growth. Our research revealed that the key criterion for peer group selection is opportunities to realize incremental economies of scale from output growth. Over the full 1994-2004 sample period for which U.S. data have been prepared we found using COS costing that the Enbridge peer group averaged 1.95% annual TFP growth, more than three times the company's actual 2000-2006 trend. The Union peer group averaged 1.84% annual TFP growth, modestly above Union's actual trend.

Our second approach to establishing TFP growth targets was to calculate the TFP growth that can be predicted from the local business conditions faced by Enbridge and Union using econometric estimates of their cost impact. This methodology involved estimates of technological change and the opportunities to realize scale economies. Using COS costing, the indicated productivity targets for Enbridge and Union were 1.54% and 1.50%, respectively.

While the econometric approact to setting TFP targets provides useful points of comparison we recommend the use of the peer group approach to set the X factors for Enbridge and Union. This approach is less sensitive to the specifics of the econometric research since it uses elasticity estimates only to weight the output index. There is less concern about whether the results of an inherently long term cost study are applicable in the medium term time frame of an IR plan. Parties may find it useful to take a look at the peers that are used in the calculations. In the present exercise, these are generally companies with rapid output growth. Some peers are smaller than Enbridge and Union, but that is because our research shows that the opportunities to realize economies do not diminish markedly with scale. The opportunity to realize scale economies relies mainly on output growth.

The econometric research used to develop TFP targets produced cost models of excellent quality. For example, the regularity conditions predicted by economic theory were satisfied at every observation and there were no negative output elasticities. In developing the models, some multicollinearity was encountered in the output variables. This is a common condition in statistical cost research that reduces the precision of elasticity estimates but does not bias the estimates. We handled this problem with the conventional remedy of a large panel data set, which pooled all of the good data on the operation of U.S. gas utilities that were available. The research provided strong support for the notion that Enbridge and Union realize material scale economies from output growth.

The chosen targets were compared to the multifactor productivity ("MFP") trends of the Canadian private business sector to calculate the PDs for each company. Statistics Canada recently revised its estimate of the recent trend in the multi-factor productivity of Canada's private business sector downward. The indicated productivity differential for Enbridge is 1.48% (1.95 – 0.47). The productivity differential for Union is 1.37% (1.84 – 0.47).

Input Price Differential

We compared the input price trends of Ontario gas utilities to that of Canada's economy using both capital costing methods. We chose the 1998-2006 period as the one ending in 2006 that was well suited for calculating the IPD using COS capital costing. We found using COS capital costing that the appropriate input price differentials for Enbridge and Union were -0.22% and -0.14% respectively. This is to say that the trend in the economy's input prices was a little less rapid than the trend in the industry's. An opposite result of similar magnitude was obtained using GD costing.

Average Use

Declining average use is being experienced by many gas utilities in North America today. The conditions encouraging declining average use include more efficient gas furnaces, better home insulation, and higher gas prices. This trend has increased the need of gas utilities for rate escalation to recover the (substantially fixed) costs of their distribution and customer services. The trend affects rates for different customer rate classes differently. Heat-sensitive loads are primarily in the residential and commercial rate classes. Where growth in the number of residential and commercial customers is brisk these service classes also have a disproportionately large impact on the growth of distributor cost.

For the PCI, the AU factor was calculated as the difference between the revenue-weighted and elasticity-weighted output indexes. Weather normalized volumes were used in these calculations. Using COS capital costing, the AU factors for Enbridge and Union are -1.28 and -0.72. The higher AU factor for Enbridge makes sense given the greater importance of residential and commercial customers in its operations. The PCI adjustment for declines in average use is designed to exclude the effect of the Lost Revenue Adjustment Mechanism ("LRAM").

Stretch Factor

The stretch factor term of the X factor reflects expectations concerning the potential for better performance under the incentives generated by the IR plan. We have relied on two sources in developing our stretch factor recommendations. One is historical precedent. In research for Board staff last year to develop an IR plan for power distributors we found that the average explicit stretch factor that has been approved for energy utilities in rate escalation indexes is around 0.50%.

A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that can be expected of utilities under alternative regulatory systems. By comparing the performance expected under an approximation to the company's current system to that expected under an approximation of the IR plan we can estimate the expected performance improvement resulting from the move to IR. The last step in the analysis is to share the expected improvement 50/50 between the company and its customers. This analysis suggests stretch factors of 0.42% for Enbridge and Union, which is close to the 0.5% precedential norm.

A third piece of information that is potentially relevant in stretch factor selection is operating efficiency. As it happens, no evidence has been brought to our attention concerning the recent operating efficiency of Enbridge or Union. We, accordingly, have no basis for adjusting the X factor for this consideration. Utilities should demonstrate superior performance with convincing benchmark evidence if they wish to receive special rate treatments. Based on the evidence at hand, we recommend a conventional 0.5% stretch factor for both companies.

Price Caps for Service Groups

PCIs for specific service groups were established by calculating X factors that were the sum of the X factor from the *summary* PCI and a special adjustment term, ADJ. The ADJ term varies by service group and effectively creates a custom X factor and PCI for each group. Original theoretical and empirical research was undertaken to provide a foundation for the design of the ADJ term. The basic idea is to effect an adjustment to X that reflects the special impact of the service group on TFP growth. This impact has a cost as well as a revenue dimension. For example, residential service is more likely than other services to have a negative ADJ because growth in the number of residential customers has a disproportionately large impact on utility cost in addition to the fact that declining average use by these customers has a disproportionately large impact on utility revenue.

Final Comment

A final comment is warranted concerning the evolution in the research methods used in this study. The project involved a number of special circumstances that occasioned the use of research methods that were complex and, in some cases, innovative.

- The GD approach to capital costing generated volatile capital prices, and there was a real risk that an improper IPD would be chosen. We responded to this dilemma by finalizing the COS approach to capital costing, which we developed over several years.
- Enbridge and Union are not surrounded by utilities, facing similar business conditions and which have reported quality standardized data for many years, which could provide the basis for a sensible regional peer group. Methods

were thus needed to deduce appropriate TFP targets from data on utilities located farther afield.

- Parties made two requests concerning PCI design that have no precedent in North American IR for energy utilities. PCIs were requested for individual service groups which assigned responsibility for declines in average use. Parties also requested a decomposition of TFP growth into its cost efficiency and average use components. Both decompositions required econometric estimates of the cost impact of output growth. These estimates also proved useful in the calculation of TFP targets using U.S. data.
- The limited sample periods available for the calculation of long run TFP trends for Enbridge and Union made it necessary to weather normalize their volume trends.
- Parties did not file evidence on their views on appropriate methods until August, five months after the issuance of our intial report. This evidence included a proposal for an entirely new approach to IR (the revenue per customer cap) and constructive criticism concerning the uses of econometrics in the design of rate adjustment mechanisms.

We have done our best to develop research methods that respond to these circumstances. These methods provide valuable information for the choice of IR plan parameters even if the final IR mechanism is comparatively simple. It is our hope that the methodological advances that have resulted from this proceeding will provide a more solid foundation for future IR initiatives in Ontario.

1. INTRODUCTION

The Ontario Energy Board ("OEB") has for many years been interested in incentive regulation ("IR") for its jurisdictional utilities. Enbridge Gas Distribution ("Enbridge"), Union Gas ("Union"), and provincial power distributors have all operated under IR plans. The approach to IR that has been favored in Ontario features rate adjustment mechanisms with inflation measures and productivity factors. Research on the historical productivity trends of utilities is considered in the development and approval of mechanisms.

In 2004, the Board convened a Natural Gas Forum to consider the future of Ontario gas utility regulation. In its final report on the Forum the Board found that its goals for the regulation of base rates are best served by multiyear IR plans with annual rate adjustment mechanisms designed with the aid of index research.[3] The Board acknowledged the challenge of determining an appropriate productivity factor but stated that "making an appropriate determination of this component will ensure that the benefits of efficiencies are shared with customers during the term of the plan".[4]

Last September, Board staff initiated a consultation process on the development of certain elements of gas IR plans. Meetings were held in October and November with utilities and other stakeholders to discuss plan design issues. Stakeholders provided several comments in these meetings that merit attention in the design of a rate adjustment mechanism.

1. There was broad consensus on the desirability of familiar macroeconomic inflation measures.
2. Some stakeholders remarked that allowed rate escalation should be no more rapid under IR than might be expected under a continuation of traditional regulation.
3. Enbridge expressed concern that the plan provide due compensation for needed capital spending, including the expected replacement of cast iron mains.

[3] OEB, *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* March 2005.
[4] *Ibid*, p. 24.

4. Enbridge and Union both expressed concern that the mechanism provide rate relief for the ongoing decline in the average use of gas by customers in their service territories.
5. Other stakeholders voiced concern about the form that an adjustment for declining average use might take. Stated reasons included:
    - a desire to understand the separate rate impacts of improved cost efficiency and use per customer trends; and
    - concern that any average use adjustment affect only the rates for the residential and commercial customers that are the chief source of the trend.

On January 5, 2007, Board staff issued a report on the progress of deliberations which discussed the potential for a price cap approach to base rate IR. The terms of IR plans would include a base year and five further years in which rates would be permitted to escalate. The gross domestic product implicit price index for final domestic demand ("GDP IPI FDD") is proposed as the PCI inflation measure. The PCI formulas would also feature an X factor composed of four terms:

- Input Price Differential ["IPD"]: (The difference between the input price trends of the economy and the industry)
- Productivity Differential ["PD"]: (The difference between the productivity trends of the industry and the economy)
- Average Use Factor ["AU"]: (An adjustment for the financial impact of declining average use) and
- Stretch Factor ["SF" or "Stretch"]: (A term to share the expected benefits of improved performance under the IR plan).

Pacific Economics Group ("PEG") is the advisor to Board staff on incentive regulation issues. Staff initially directed PEG to undertake index research that would support the design of PCIs for Enbridge and Union. It subsequently requested the development of revenue cap indexes ("RCIs") and of PCIs for particular service groups. Our study addressed the input price and productivity trends of Enbridge, Union, and a group of U.S. gas utilities.

Following the issuance of a preliminary report dated March 30, 2007, several stakeholders filed comments.

1. TransCanada Energy ("TCE") and TransCanada PipeLines argued that PCIs for individual service groups should reflect trends in the corresponding rates. Non-residential customers should not be asked to fund revenue shortfalls resulting from declines in residential average use. TCE encouraged consideration of a separate PCI for unbundled transportation.
2. The Industrial Gas Users Association and the London Property Management Association both expressed concerned about assumptions underlying the analysis and the choice of sample periods.
3. Union argued that productivity targets should be based on industry and not on company specific trends. The company also claimed that it should not be assigned a stretch factor due to the stronger performance incentives resulting from infrequent rate cases in the company's recent past.
4. Several stakeholders expressed concern with our preliminary results for the price cap index for Union's non-residential customers.

These and other comments of stakeholders and Board staff prompted upgrades in our methods that materially altered some of the research results. A final report on the new work was issued June 20.

Over the summer, parties to the proceeding filed evidence that have prompted further revisions in our methodology. The evidence included a proposal by Enbridge Gas Distribution for a revenue per customer approach to IRM. Stakeholders asked for an update of our research to reflect 2006 data for Enbridge and Union. Also, some of the Statistics Canada indexes used in our research have been revised. Additionally, PEG staff had occasion to revisit the issue of its weather normalization method.

Additional research has been undertaken in reponse to these new developments. The methodology was changed, most notably to add line miles as a measure of output and to adapt the weather normalization methods used by Union and Enbridge. New data were employed, and a revenue per customer cap index was developed.

This document reports on our new research. Section 2 of the report provides an introduction to indexing and considers in general terms its potential role in the design of rate escalation mechanisms. Highlights of our indexing research for the Board are presented in Section 3. Additional, more technical details of the research, along with some information on the qualifications of the research team, are provided in the Appendix.

2. INDEX RESEARCH AND INCENTIVE REGULATION

Input price and productivity research has been used for more than twenty years to design the rate adjustment mechanisms of IR plans. The rationale for such research, which employs index logic, provides the basis for the PD, IPD, and AU terms in Staff's proposed price cap indexes. It also sheds light on the best indexing methods to use in PCI design.

To understand the logic, it is necessary first to have a high level understanding of input price and productivity indexes. We provide this in Section 2.1. There follows in Section 2.2 an extensive non-technical explanation of the use of indexing in IR plan design. Details of our index research in this project can be found in Section 3.

2.1 Price and Productivity Indexes

2.1.1 TFP Basics

A productivity index is the ratio of an output quantity index to an input quantity index.

$$Productivity = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [1]$$

It is used to measure the efficiency with which firms convert inputs to outputs. The indexes that we developed for this study are designed to measure productivity trends.

The growth trend of such productivity indexes is the difference between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Output\ Quantities - trend\ Input\ Quantities. \qquad [2]$$

Productivity thus grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index. Productivity growth is characteristically volatile due to fluctuations in output and the uneven timing of certain expenditures. The volatility is often greater for individual companies than for an aggregation of companies such as a regional industry.

The input quantity index of an industry summarizes trends in the amounts of production inputs used. Growth in the usage of each input category considered separately is measured by a subindex. Capital, labour, and miscellaneous materials and services

(“M&S”) are the major classes of base rate inputs used by gas utilities. A TFP index measures productivity in the use of all inputs. An index that measures productivity in a subset of the full array of inputs is called a partial factor productivity (“PFP”) index.

The output (quantity) index of a firm or industry summarizes trends in one or more dimensions of the amount of work performed. Each dimension considered separately is measured by a subindex. Output indexes can summarize the trends in component subindexes by taking a weighted average of them.

In designing an output index, the choice of subindexes and weights depends on the manner in which it is to be used. One possible objective is to measure the impact of output growth on company *cost.* In that event, it can be shown that the subindexes should measure the dimensions of workload that drive cost. The weights should reflect the relative importance of the cost elasticities that correspond to these drivers. The elasticity of cost with respect to an output quantity is the percentage change in cost that will result from a 1% change in the quantity.

Output indexes may, alternatively, be designed to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* and the weights should be the share of each determinant in revenue. Billing determinants are the quantities companies use to calculate invoices. An invoice from Tim Horton’s, for instance, may reflect the number of donuts purchased. In the gas utility industry, the relevant determinants include delivery volumes, contract demand, and the number of customers served.

Rates for gas utility services commonly feature customer (sometimes called access) charges and either volumetric charges or demand charges. Rate designs frequently don’t reflect the drivers of utility cost well. For example, the costs of distribution and customer services are commonly driven chiefly by customer growth, whereas distribution revenue is commonly driven chiefly by growth in the delivery volumes to residential and commercial customers. Under these circumstances, a TFP index calculated using a revenue-weighted output index will be sensitive to trends in average use. Measured TFP growth will be slowed by declining average use and accelerated by increasing average use. Research by PEG has shown that declines in average use are being experienced by most North American gas utilities today. Contributing factors include gas prices above historic norms and improvements in the efficiency of furnaces and other gas-fired equipment.

2.1.2 Sources of TFP Growth

Theoretical and empirical research has found the sources of TFP growth to be diverse.[5] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of TFP growth. These economies are available in the longer run when cost characteristically grows less rapidly than output. In that event, output growth can slow unit cost growth and raise TFP. A company's potential for scale economy realization depends on its current operating scale and on the pace of its output growth. Incremental scale economies will typically be greater the more rapid is output growth.

A third important source of TFP growth is change in X inefficiency. X inefficiency is the degree to which individual companies operate at the maximum efficiency that technology allows. Usage of capital, labour, and materials and services all matter. TFP will grow (decline) to the extent that X inefficiency diminishes (increases). The potential of a company for TFP growth from this source is greater the greater is its current level of operating inefficiency. Evidence on operating efficiency can be produced using statistical benchmarking.

An important source of TFP growth in the shorter run is the degree of capacity utilization. Producers in most industries find it uneconomical to adjust production capacity to short-run demand fluctuations. The capacity utilization rates of industries therefore fluctuate. TFP grows (declines) when capacity utilization rises (falls) because output is apt to change much more rapidly than capacity.

Another short-run determinant of TFP growth is the intertemporal pattern of expenditures that must be made periodically but need not be made every year. Expenditures of this kind include those for replacement investment and maintenance. A surge in such expenditures can slow productivity growth and even result in a productivity decline.

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[5] This section relies heavily on research detailed in Denny, Fuss, and Waverman (1981). A mathematical treatment can be found in Section A.8 of the Appendix.

Uneven spending is one of the reasons why the TFP growth of individual utilities is often more volatile than the TFP growth of the corresponding industry.

A sixth important source of TFP growth is changes in the miscellaneous other external business conditions that affect operating cost. A good example for a gas utility is the number of electric customers served. Economies of scope are possible from the joint provision of gas and electric service. Growth in the number of electric customers served can, by reducing the cost of gas distribution, boost productivity growth.

TFP is often calculated using output quantity indexes with revenue share weights. In that event, it can be shown that TFP growth also depends on the degree to which the output growth affects *revenue* differently from the way that it affects *cost.* This can be measured by the difference in the growth rates of an output quantity index designed to reflect *revenue* impact and one that is designed to reflect *cost* impact. This result will prove useful in the design of the average use factor, as we discuss further in Section 2.3 below.

2.1.3 Price Indexes

Price indexes are used to make price comparisons. The price indexes used in PCI design are used to measure price trends. Indexes can summarize the trends in the prices of numerous products by taking weighted averages of the price trends of individual products or groups of products. An index of trends in the prices paid by a utility uses cost shares as weights because these weights capture the impact of input price growth on cost. An index of trends in the rates charged by utilities uses revenue shares as weights because these weights reflect the impact of rate growth on revenue.

2.2 Role of Index Research in Regulation

2.2.1 The Unit Cost Standard for PCI Design

The rate escalation mechanism is one of the most important components of an IR plan. Such mechanisms can substitute for rate cases as a means to adjust utility rates for trends in input prices, demand, and other external business conditions that affect utility earnings. As such, they make it possible to extend the period between rate cases and strengthen utility performance incentives. The mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers.

An approach to the design of rate escalation mechanisms has been developed in North America using index logic that is grounded in theoretical and empirical research. The analysis begins with consideration of the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return. In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$trend\ Revenue = trend\ Cost. \qquad [3]$$

The assumption of a competitive rate of return is applicable to utility industries and even to individual utilities. It is also applicable to unregulated, competitively structured markets.

Consider, now, that the trend in the revenue of any firm or industry is the sum of the trends in appropriately specified output price and quantity indexes.

$$trend\ Revenue = trend\ Output\ Quantities + trend\ Output\ Prices. \qquad [4]$$

The output quantity index in this formula is designed to measure the impact of output growth on revenue. It is thus constructed from *revenue* shares and summarizes the trends in billing determinants. Relations [3] and [4] together imply that the trend in an index of the prices charged by an industry earning a competitive rate of return equals the trend in its unit cost index.

$$trend\ Output\ Prices = trend\ Cost - trend\ Output\ Quantities = trend\ Unit\ Cost. \qquad [5]$$

The long run character of this important result merits emphasis. Fluctuations in input prices, demand and other external business conditions will cause earnings to fluctuate in the short run. Fluctuations in certain expenditures that are made periodically can also have this effect. An example would be a major program of replacement investment for a distribution system with extensive asset depreciation. Since capacity adjustments are costly, they will typically not be made rapidly enough to prevent short-term fluctuations in returns around the competitive norm. The long run is a period long enough for the industry to adjust capacity to more secular trends in market conditions.

The result in [5] provides a conceptual framework for the design of price cap indexes. We will call this framework the industry unit cost paradigm. Growth in a utility's rates can be measured by an actual price index. A PCI can limit the growth in this index. A stretch factor established in advance of plan operation can be added to the formula which slows PCI growth in a manner that shares with customers the expected benefits of performance improvements due to the stronger performance incentives of the IR plan.[6] A PCI is then *calibrated* to track the industry unit cost trend to the extent that

$$trend\ PCI\ =\ trend\ Unit\ Cost + Stretch\ Factor. \qquad [6]$$

A properly calibrated PCI provides automatic rate adjustments for a wide array of external business conditions that affect the unit cost of utility operation. It can therefore generate compensatory rates and reduce utility operating risk without weakening performance incentives. This constitutes a remarkable advance in the technology for utility regulation.

The design of PCIs that track the industry unit cost trend is aided by an additional result of index logic. It can be shown that the trend in an industry's *total* cost is the sum of the trends in appropriately specified industry input price and quantity indexes.

$$trend\ Cost = trend\ Input\ Prices + trend\ Input\ Quantities. \qquad [7]$$

It follows that the trend in an industry's *unit* cost is the difference between the trends in industry input price and TFP indexes.[7]

$$trend\ Unit\ Cost = trend\ Input\ Prices - trend\ TFP. \qquad [8]$$

Furthermore, a PCI can be calibrated to track the industry unit cost trend if it is designed in accordance with the following formula:

$$trend\ PCI\ = trend\ Input\ Prices - \left(trend\ TFP + Stretch\ Factor\right). \qquad [9]$$

The X factor term of the PCI would, in this case, be the sum of a TFP trend and a stretch factor.

An important issue in the design of a PCI is whether it should track short run or long run unit cost growth. An index designed to track short run growth will also track the long run growth trend if it is used over many years. An alternative approach is to design the

[6] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

[7] Here is the full logic behind this result:

$$\begin{aligned} trend\ Unit\ Cost &= trend\ Cost\ \text{-}\ trend\ Output\ Quantities \\ &= \left(trend\ Input\ Prices + trend\ Input\ Quantities\right) - trend\ Output\ Quantities \\ &= trend\ Input\ Prices \\ &\quad - \left(trend\ Output\ Quantities\ \text{-}\ trend\ Input\ Quantities\right) \\ &= trend\ Input\ Prices - trend\ TFP \end{aligned}$$

index to track *only* long run trends. Different approaches can, in principle, be taken for the input price and productivity components of the index.

One issue to consider when making the choice is the manner in which short-run input price and productivity fluctuations affect prices in competitive markets. Inflation in the prices charged in such markets sometimes accelerates (decelerates) rather promptly when input price inflation accelerates (decelerates). Airlines and trucking companies, for instance, sometimes hike prices in periods of rapid fuel price growth.

On the other hand, prices in competitive markets typically do not fall (rise) when TFP rises (falls). For example, TFP typically falls (rises) in the short run in response to a slackening (strengthening) of demand. These same developments typically have the reverse effect on prices in unregulated markets.

A second consideration is the effect on risk. A price cap index that tracks short-term fluctuations in industry unit cost increases rate volatility but reduces utility operating risk. This can permit an extension of the period between rate reviews that strengthens performance incentives.

Consider, next, the costs of designing PCIs and using them to make rate adjustments. This cost depends in large measure on data availability. Data on price trends are available more quickly than the cost and quantity data that are needed, additionally, to measure TFP trends. Final data needed to compute the TFP growth of US gas distributors in 2006, for instance, will not be available until the fall of 2007. The longer lag in the availability of cost and quantity data is due chiefly to the fact that these data typically come from *annual* reports whereas price indices are often calculated and reported on a *monthly or quarterly* basis. It is also germane that the calculation of TFP indexes can be quite a bit more complicated than the calculation of price indexes.

Implementation cost also depends on the feasibility of calculating current long run trends accurately. Methods have been developed to measure the recent long run trend in the TFP of the industry. For example, the drivers of fluctuations in volatile delivery volumes are well understood, and these volumes can be normalized so that calculations of the long term trend are less sensitive to the choice of a sample period. The recent long run trend in an industry's TFP is, moreover, often if not always a good proxy for the *prospective* trend over the next several years.[8]

The use of historical data on industry input price trends to calculate the prospective future trend is more problematic. Industry input price indexes are often volatile. The calculation of an average annual growth rate thus depends greatly on the choice of the sample period. It can be difficult to reach consensus on what sample period would yield a long term input price trend. One reason is that research on the short run drivers of fluctuations in utility input prices is not well advanced. Absent a scientific basis for sample period selection, the choice of a sample period can engender controversy and raise the risk of IR for utilities. Higher regulatory risk can raise the cost of funds and reduce thereby the net benefits of IR.

Historical trends in input prices are, furthermore, sometimes poor predictors of the trends that will prevail in the near future. Suppose, by way of example, that there has been rapid input price inflation in the last ten years but that the expectation is for more normal inflation in the next five years. In this situation, regulators would presumably be loath to fix PCI growth at a rate that reflects the 10-year historical trend.

Examination of input prices in the gas distribution industry suggests that they are somewhat volatile. Since gas distribution is capital intensive, the summary input price index is quite sensitive to fluctuations in the price of capital. The trend in a properly constructed capital price index depends on trends in plant construction costs and the rate of return on capital. Both of these components are more volatile than the general run of prices in our economy. The rate of return on capital depends on the balance between the supply of and the demand for funds, and reflects expectations regarding future price inflation.[9] From the late 1970s through the mid 1980s, for instance, yields on long-term bonds were far above historical norms due in large measure to inflation worries spurred by oil price shocks. They fell gradually for many years thereafter as concerns about inflation receded. More recently, long bond yields have been held down by efforts of the governments of China and other

[8] Reliance on the long run trend can be problematic, however, when applied to utilities that contemplate major capital additions.

[9] The rate of return on capital also reflects return on equity. Returns on equity have also been volatile and are not highly correlated with bond yields.

countries with large export sectors to control exchange rates. Speculation on when and how much these policies will change is a staple of the financial press.

A sensible weighing of these considerations leads us to conclude that different treatments of input price and productivity growth are in most cases warranted when a PCI is calibrated to track the industry unit cost trend. The inflation measure should track *short term* input price growth. The X factor, meanwhile, should generally reflect the long run trend of TFP.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long run industry TFP trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual TFP calculations.

2.2.2 Input Price and Productivity Differentials

Resolved that the PCI inflation measure should track recent price growth, other important issues of its design must still be addressed. One is whether it should be *expressly* designed to track industry input price inflation as per relation [9]. There are several precedents for the use of such industry-specific inflation measures in rate adjustment indexes. Such a measure was used in one of the world's first large scale IR plans, which applied to US railroads. Staff of California Public Utilities Commission ("CPUC") developed an approach to measuring industry input price inflation that was used in several plans. OEB staff chose an industry specific inflation measure, which it called the "IPI," for the first price cap plan for Ontario power distributors.

Notwithstanding such precedents, the majority of rate indexing plans approved worldwide do not feature industry-specific inflation measures. They instead feature measures of economy-wide *output* price inflation such as the GDPIPIs. These are computed on a quarterly basis by Stats Canada to measure inflation in the prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products and also include capital equipment. The GDPIPI for final domestic demand excludes prices of exports, which are volatile in Canada's resource-intensive economy.

Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in rate adjustment indexes. One is that they are available from respected and impartial sources such as the Federal government. Customers are more familiar with them, and this facilitates acceptance of rate indexing generally. There is no need to go through the chore of annual index calculations. Controversies over the design of an industry-specific price index are sidestepped. However, the use of a macroeconomic measure involves its own PCI design challenges, as we will now discuss.

When a macroeconomic inflation measure is used, the PCI must be calibrated in a special way if it is to track the industry unit cost trend. Suppose, for example, that the inflation measure is a GDPIPI. In that event we can restate relation [9] as

$$growth\ PCI = growth\ GDPIPI - \left[trend\ TFP + (trend\ GDPIPI - trend\ Input\ Prices) + Stretch\ Factor\right] \quad [10]$$

It follows that the PCI can still conform to the industry unit cost standard provided that the X factor corrects for any tendency of GDPIPI growth to differ from industry input price growth.

Consider now that the GDPIPI is a measure of *output* price inflation. Due to the broadly competitive structure of North America's economy, the long run trend in the GDPIPI is then the difference between the trends in input price and TFP indexes for the economy.

$$trend\ GDPIPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy}. \quad [11]$$

If the input price trends of the industry and the economy are fairly similar, the growth trend of the GDPIPI can be expected to be slower than that of the industry-specific input price index by the trend in the economy's TFP growth. In a period of rapid TFP growth this difference can be substantial. When the GDP-IPI is used as the inflation measure, it follows that the PCI already tracks the input price and TFP trends of the economy. X factor calibration is warranted only to the extent that the input price and TFP trends of the utility industry differ from those of the economy.

Relations [10] and [11] are often combined to produce the following formula for PCI design:

$$growth\ PCI = growth\ GDPIPI - \begin{bmatrix} \left(trend\ TFP^{Industry} \text{-} trend\ TFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} \text{-} trend\ Input\ Prices^{Industry}\right) + Stretch \end{bmatrix}. \quad [12]$$

It follows that when the GDPIPI is employed as the inflation measure, the PCI can be calibrated to track the industry unit cost trend when the X factor has two calibration terms: a productivity differential and an input price differential. The productivity differential is the difference between the TFP trends of the industry and the economy. X will be larger, slowing PCI growth, to the extent that the industry TFP trend exceeds the economy-wide TFP trend that is embodied in the GDP-IPI. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.

The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the utility industry grow at different rates than prices in the economy as a whole. For example, labour prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also possible that the industry has a different mix of inputs than the economy. Gas distribution technology is, for example, more capital intensive than the typical production process in the economy. It is therefore more sensitive to fluctuations in the price of capital.

The difficulties, discussed in the preceding section, in establishing a long-term input price trend complicate identification of an appropriate input price differential. For example, the difference between the average annual growth rates of input prices of the industry and the economy is sensitive to the choice of the sample period. It is less straightforward to establish the relevant sample period for a comparison of long-term industry and economy input price trends than it is for an analogous TFP trend comparison. Even if we could establish a differential between the long term trends it could differ considerably from the trend expected over the prospective plan period. This situation invites gaming over the sample period used to calculate the input price differential. Controversy is possible, additionally, over the method used to calculate the price of capital.

2.2.3 Average Use Factor

Board staff and stakeholders were noted in Section 1 to have expressed a desire to have a separate PCI adjustment for declines in average use that are not due to demand-side management activity *i.e.* it excludes the effect of the Lost Revenue Adjustment Mechanism. Our discussion in Section 2.1.2 on the sources of productivity growth suggests a rigorous means of implementing this. We found that when output growth is measured using revenue weights, as is appropriate in PCI design, TFP growth depends in part on the difference between the growth rates in revenue and elasticity weighted output quantity indexes. The difference is apt to be material for energy distributors since growth in the base rate revenues of distributors typically depends chiefly on the growth in delivery volumes whereas growth in the cost of base rate inputs depends chiefly on other billing determinants such as the number of customers served.

Suppose, now, that we use an elasticity weighted output quantity index to measure TFP growth. The requisite elasticities can be estimated econometrically using historical data on the costs and quantities of gas utilities. The productivity index now has the more narrow mission of measuring the trend in cost efficiency. The PCI will still conform to the industry unit cost standard provided that we include a separate term in the PCI growth rate formula to reflect the difference between the trends in revenue and elasticity weighted output quantity indexes. This term can be called the average use factor since it effectively restores the ability of the PCI to capture the impact of average use trends on unit cost.

$$\begin{aligned} growth\ PCI\ &= growth\ GDPIPI \\ &\quad - \left[\begin{array}{l} \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + \\ \left(trend\ Output^{Revenue\text{-}Weighted} - trend\ Output^{Elasticity\text{-}Weighted}\right) + Stretch \end{array}\right] \quad [13] \\ &= growth\ GDPPI - (PD + IPD + AU + Stretch). \end{aligned}$$

The AU factor can be based on long term trends much like the PD and IPD. This logic is spelled out in greater detail in the Appendix.

2.2.4 Revenue per Customer Cap

A revenue per customer cap is a rate adjustment mechanism designed to limit growth in a company's revenue per customer. Such an index can be paired with a balancing account that ensures that the indicated revenue requirement is ultimately recovered. This tandem of IR plan provisions provides automatic compensation to the utility for declines in average use. The ratepayer also absorbs the risk of volume fluctuations due to weather and other volatile demand drivers.

Index logic provides a framework for the design of a revenue per customer cap. Note first that relations [3] and [7] imply that

trend Revenue = trend Input Prices+ trend Input Quantities

= trend Input Prices – (trend Customers - trend Input Quantities)

+ trend Customers[10] [14]

Rearranging the terms of [14] we now obtain

trend Revenue - trend Customers = trend Input Prices

- (trend Customers - trend Input Quantities)

or, equivalently,

trend Revenue per Customer

= trend Input Prices – (trend Customers - trend Input Quantities) [15]

The trend in revenue per customer thus depends on input price inflation and the efficiency with which the firm makes customer additions.[11]

An alternative derivation for [15] can also be used. We know that

trend Revenue – trend Customers

= trend Prices $^{\text{Revenue Weighted}}$ + trend Output$^{\text{Revenue Weighted}}$

= trend Input Prices – (trend Output$^{\text{Revenue Weighted}}$ – trend Input Quantities)

+ trend Output$^{\text{Revenue Weighted}}$ - trend Customers

Since the revenue-weighted output terms in this formula cancel out it reduces to [15]. A revenue per customer cap therefore does not require a revenue-weighted output index.

Using logic similar to that which we used to develop the AU factor we can restate [15] as

trend Revenue per customer

[10] A CPI-X+ Customers formula was approved in 1999 by the OEB to escalate the revenue requirement for O&M expenses of Consumers Gas (now Enbridge).

[11] The analogous formula for a *price* cap index is

trend revenue/output= trend Input Prices- (trend Output- trend Input Quantities)

where the output index is revenue-weighted.

$$= \text{trend Input Prices} - [(\text{trend Output}^{\text{Elasticity Weighted}} - \text{trend Input Quantities}) + (\text{trend Customers} - \text{trend Output}^{\text{Elasticity Weighted}})]$$

$$= \text{trend Input Prices} - (\text{trend TFP}^{\text{industry}} + RC)$$

We find that the revenue per customer of a firm earning a competitive rate of return depends on input prices, a TFP index based on elasticity-weighted output, and the difference between customer and output index growth. We will call the extra term a revenue per customer adjustment or RC factor. It is analogous to the AU term in a price cap index.

If the GDP-IPI is used as the inflation measure, the following formula for a revenue per customer cap is indicated by this analysis:

$$\begin{aligned} growth\ Revenue/Customer &= growth\ GDPIPI - [PD + IPD + RC + SF] \\ &= growth\ \ GDPIPI - X \end{aligned} \quad . \qquad [16]$$

Here the PD, IPD, and SF terms are the same as in a PCI formula [13]. There is no AU factor, or any other use of a revenue-weighted output index. Provided that revenue is allocated to service groups by traditional means there is no need to calculate revenue per customer caps for specific service groups. Notice that if the growth in GDPIPI equals X, this formula becomes a revenue per customer *freeze*:

growth Revenue/Customer = 0.[12]

2.3 Conclusions

In concluding this section it may prove useful to summarize key findings that we have used in our index research for the Board.

1. In a PCI formula of GDPIPI-X form, the PCI can be calibrated to track the industry unit cost trend provided that it contains four terms: PD, IPD, AU, and SF.
2. In computing the PD, the industry TFP trend is calculated using an elasticity-weighted output index.
3. The average use factor is the difference between the trends in revenue and elasticity weighted output indexes.

[12] This formula has been used in an IR plan for the gas distributor services of Baltimore Gas & Electric.

4. Index logic also provides formulas for revenue per customer caps. A revenue weighted output index is not required in this formula.

3. EMPIRICAL RESEARCH

This section presents an overview of our research on the input price and productivity trends of Ontario and US gas utilities. We begin by discussing data sources and the definition of cost, topics that are equally relevant to the input price and productivity work. We then discuss in detail our research on productivity, declining use, and input price trends, the stretch factor, PCIs for particular service groups, and revenue cap indexes. The section concludes with an explanation of how research in each of these areas was used to construct PCIs applicable to specific service groups. The discussions here are largely non-technical. Additional and more technical details of the research are provided in the Appendix which follows.

3.1 Data Sources

3.1.1 United States

The primary source of the data used in our US gas utility cost research has changed over time. For the earliest years of the sample period the primary source was *Uniform Statistical Reports* ("USRs"). Many US gas utilities file these annual reports with the American Gas Association.[13]

USRs are unavailable for most sampled utilities for the later years of the sample period. Some utilities do not file USRs. Some that do file do not release them to the public. The development of a satisfactory sample therefore required us to obtain operating data from alternative sources including, most notably, reports to state regulators. Companies filing reports with state regulators often use as templates the Form 2 report that interstate gas pipeline companies file with the Federal Energy Regulatory Commission ("FERC"). A uniform system of accounts has been established by the FERC to help utilities prepare this filing. Gas utility operating data from state reports are also compiled by commercial venders such as Platts. We obtained our 2004 operating data from the Platts *GasDat* package.

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[13] USR data for some variables of interest are aggregated and published annually by the AGA in *Gas Facts*.

Other sources of data were also employed in the US research. Detailed data on the delivery volumes and customers served by US gas utilities were obtained from Form EIA 176. Good data on contract demands are unfortunately, not available from this or any other US source of which we are aware. Data on US heating degree days ("HDDs") were obtained from the National Climatic Data Center. Data on input prices were drawn from several sources. Whitman, Requardt & Associates prepare Handy Whitman Indexes of trends in the construction costs of US gas utilities. Other sources of input price data include R.S. Means and Associates; the Bureau of Labor Statistics ("BLS") of the US Department of Labor; and the Energy Information Administration ("EIA") of the US Department of Energy.

Our TFP trend calculations are based on quality data for 36 US utilities. The sample includes most of the nation's larger utilities.[14] The sampled utilities are listed by region in Table 1. Inspection of the table reveals that they account for about 45% of gas deliveries in the continental US. The regional distribution of sampled companies is uneven. For example, California utilities accounted for about 32% of the customers in the sample but for only 15% of all customers in the continental US. Utilities in the South Central States account for 2.5% of the customers in the sample but almost 15% of those in the continental US.

The sampled utilities vary in their involvement in gas storage and transmission. A few companies (*e.g.* East Ohio Gas, Pacific Gas & Electric, and Southern California Gas) are, like Union, extensively involved in both activities. Others (*e.g.* NICOR Gas, operator of extensive Illinois storage facilities) are extensively involved in one of the two activities. Many of the companies are not extensively involved in either activity.

It is also interesting to compare the number of customers served by the sampled US utilities to those of Enbridge and Union. In 2004, the Ontario companies served more than 1.6 million and 1.2 million customers, respectively. Union operates a sizable gas transmission and storage system in addition to its distributor operations. Thus, both operate at scales that are well above the norms for our sample. However, the sample includes several companies with similar or larger operating scales.

[14] Large distributors that are not represented in the sample include Atmos (owner of the former Lone Star Gas System), Columbia Gas of Ohio, Entex, Laclede Gas, Michigan Consolidated Gas, Minnegasco, and National Fuel Gas.

Table 1

SAMPLED US GAS UTILITIES FOR TFP RESEARCH

Region	Company	Number of Customers (2004)	Percent Sample Total	Percent Continental US
Northeast				
	Baltimore Gas & Electric	624,862		
	Central Hudson Gas & Electric	69,081		
	Connecticut Natural Gas	151,127		
	Consolidated Edison of New York	1,041,458		
	Niagara Mohawk	560,566		
	New Jersey Natural Gas	453,983		
	Nstar Gas	252,576		
	Orange and Rockland Utilities	123,577		
	PECO Energy	464,619		
	People's Natural Gas (PA)	355,134		
	PG Energy	159,242		
	Public Service Electric & Gas	1,693,048		
	Rochester Gas and Electric	293,334		
	Southern Connecticut Gas	170,817		
	Total	*6,413,424*	*20.5%*	
	EIA Regional Total	*14,210,646*		*20.7%*
Southeast				
	Atlanta Gas Light	1,532,615		
	Public Service of North Carolina	390,824		
	Washington Gas Light	980,686		
	Total	*2,904,125*	*9.3%*	
	EIA Regional Total	*6,554,338*		*9.5%*
Midwest and Plains				
	Consumers Energy	1,690,874		
	East Ohio Gas	1,217,546		
	Illinois Power	414,015		
	Madison Gas and Electric	131,674		
	North Shore Gas	153,856		
	NICOR Gas	2,092,607		
	Peoples Gas Light & Coke	812,705		
	Wisconsin Gas	570,927		
	Wisconsin Power & Light	169,216		
	Total	*7,253,420*	*23.2%*	
	EIA Regional Total	*20,348,354*		*29.6%*

Region	Company	Number of Customers (2004)	Percent Sample Total	Percent Continental US
South Central				
	Alabama Gas	460,921		
	Louisville Gas and Electric	316,311		
	Total	*777,232*	*2.5%*	
	EIA Regional Total	*10,240,944*		*14.9%*
Southwest				
	Southwest Gas	1,526,462		
	Questar	777,555		
	Total	*2,304,017*	*7.4%*	
	EIA Regional Total	*4,679,222*		*6.8%*
Northwest				
	Cascade Natural Gas	217,336		
	Northwest Natural Gas	586,461		
	Puget Sound Energy	661,739		
	Total	*1,465,536*	*4.7%*	
	EIA Regional Total	*2,282,626*		*3.3%*
California				
	Pacific Gas & Electric	4,030,373		
	San Diego Gas & Electric	805,772		
	Southern California Gas	5,266,356		
	Total	*10,102,501*	*32.4%*	
	EIA Regional Total	*10,432,623*		*15.2%*
Total For Sample		31,220,255		
Industry Total *		68,748,753		
Percentage of US Total		45.4%		
Number of Sampled Firms		36		
Average Customers of Sampled Companies		867,229		

* Source for US Total: US Energy Information Administration, *Natural Gas Annual 2004*

3.1.2 Ontario

The primary sources of data used in our research on the index trends of Ontario gas utilities were Enbridge and Union. Most of the data were filed by the companies in regulatory proceedings. The OEB has developed a uniform system of accounts for gas utilities but at this time they are not required to file some of the detailed data that are itemized in these accounts. Partly for this reason, there are inconsistencies in the data that Enbridge and Union made available for this study.

Other sources of data were also used in the Ontario indexing research. These were used primarily for input price data. The source for almost all of these supplemental data was Statistics ("Stats") Canada.

3.2 Defining Cost

The trends in input price indexes and in the input quantity indexes used in TFP research were noted in Section 2.1 to be weighted averages of the trends in subindexes for different input groups. In indexes of each kind, the weight for each group is based on its share of the applicable total cost. The definition of cost and its breakdown into input groups is thus an important part of index design.

For all sampled utilities in our study, the applicable total cost was calculated as applicable O&M expenses plus the cost of gas plant ownership. Applicable O&M expenses were defined as the total net (uncapitalized) O&M expenses of the utility less any expenses for natural gas production or procurement, transmission services provided by others, or franchise fees. The operations corresponding to this definition of cost include distribution (local delivery), account, information, and other customer services, and any storage and transmission services that a utility may provide.

The input price and quantity indexes both featured three input categories: capital, labour, and materials and services ("M&S"). We explain here how each of these costs was calculated. The cost of **labour** was defined as the salaries and wages that contributed to net O&M expenses plus all expenses for pensions and other benefits. *Net* rather than *gross* salaries and wages are required to avoid double counting labour expenses that utilities capitalize. This reduces the precision of our calculations of that company's input price and productivity trends. In calculating the cost share for labour we also included expenses for pensions and other benefits. The pension and other benefit expenses attributable to net O&M were provided by Union and were, for the most part, estimated by PEG for Enbridge. Lacking a good basis for analogous estimates for US utilities we used their reported pension and benefit expenses without adjustment.

The cost of **natural gas** used in system operation was itemized only by Union, which operates numerous compressors on its transmission and storage system. Commentary by parties since the issuance of our June report revealed that the cost of this gas will be recovered by a separate mechanism during the envisioned IRM period. We, accordingly, exclude this cost from the calculations in our latest research.

The cost of **M&S** inputs was defined to be applicable O&M expenses net of expenses for labour and (in the case of Union) natural gas. This residual input category includes the services of contract workers, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services. The M&S expenses of Enbridge and Union were reduced further by the reported demand-side management expenses of the companies.

The cost of **capital** was calculated using two approaches: geometric decay ("GD") and an alternative approach to capital costing that is designed to reflect how capital cost is calculated under cost of service ("COS") regulation. The GD approach is the one that PEG has traditionally used in its productivity research and that consultants for Union Gas used in that company's previous IR proceeding. This approach features replacement (current dollar) valuation of utility plant and a constant rate of depreciation. The value of plant in a given year depends on the current cost of installing plant and not on the costs in prior years. However, the cost of plant ownership is calculated net of any resulting capital gains. The salient features of the COS approach to capital costing are a book (historic dollar) valuation of plant and straight line depreciation. The comparative advantages of these approaches are discussed further in section 3.5.2.

Both capital costing methods require the decomposition of cost into a price and a quantity in order to calculate industry input price and productivity trends. The cost of capital is thus the product of a capital quantity index and an index of the price of capital services. The capital price is sometimes called a rental or service price since it reflects the cost of owning a unit of capital much like prices are expected to do in competitive rental markets. The capital quantity index is, effectively, an index of the real (inflation-adjusted) value of plant where indexes of utility construction costs are used as deflators.

The capital service price indexes include, for both approaches to capital costing, terms for opportunity cost (return to debt and equity holders) and depreciation. The capital service price trend is thus a function of trends in construction costs, depreciation rates, and the cost of acquiring funds in capital markets. The GD capital service price includes, additionally, a term for capital gains. The formula for this price can be restated in such a manner as to show that it depends on the *real* rate of return on plant ownership, the difference between the nominal return and the growth rate of construction costs. This return can be volatile because the cost of funds is itself quite variable and doesn't always rise (fall) when capital gains rise.

We initially computed indexes of the cost of funds for Enbridge and Union using the 65/35 weighting of debt and equity that until recently was typical of their regulation. Commentary by stakeholders has since prompted us to revise this ratio to 64/36 to reflect a recent change in Board policy. We used the Ontario cost of funds thus computed in our US research to promote comparability of results.

3.3 Productivity Research

3.3.1 Sample Period

In choosing a sample period for a TFP study it is desirable that the period include the latest available data. It is also desirable for the period to reflect the long run productivity trend. We generally use a sample period of at least 10 years to fulfill this second goal.

We have gathered US data for the 1994-2004 period and find that, using weather normalized delivery volumes, this is a reasonable period for the calculation of the long term productivity trend. As for the Ontario utilities, sample period selection was complicated by the fact that the industry was restructured in the late 1990s to remove sizable utility appliance sales, rental, and maintenance programs. Inclusion of data from pre-restructuring years can result in TFP trends that are not necessarily reflective of what can be achieved prospectively. Note, also, that Enbridge reported that a change in accounting practices compromised the comparability of data from the 1990s. Faced with these circumstances we originally chose to focus on the 2000-2005 period for our Ontario productivity research.[15] Data for 2006 have since become available and these have been incorporated into the study. Since a seven year sample period may not be ideal for measuring long term productivity trends, it is imperative that volume data used in this analysis be weather normalized.

3.3.2 Econometric Cost Research

The index logic traced in Section 2.2 revealed that output quantity indexes featuring cost elasticity weights are useful in the design of rate and revenue cap indexes. Most notably, they can be used to calculate TFP indexes that focus on cost efficiency trends as requested by stakeholders.[16] The TFP indexes used in this study for both US and Canadian companies employed output indexes with weights that are based on estimates of the elasticity of cost with respect to output. These estimates were drawn from an econometric model of the relationship between the ("total") cost of gas utility base rate inputs and various business conditions. Econometric estimates of the cost impact of business conditions are also useful in fashioning TFP targets for Enbridge and Union from U.S. data and for designing PCIs for particular service classes.

We estimated the parameters of two cost models using US data for the full 1994-2004 sample period.[17] [18] One model was based on the COS approach to capital costing; the other on the GD approach. Using both models, we were able to identify a number of statistically significant drivers of gas utility cost and to achieve a high degree of power to explain variations in the sample data.

The choice of output quantity variables for the econometric cost research was limited by the available US data. Data are available for the number of customers served, for transmission and distribution line miles, and for the volumes delivered to major customer groups (*e.g.* residential, commercial, industrial, and generation). Our econometric research and the resultant elasticity-weighted output indexes constructed from them originally employed three subindexes: the volume of deliveries to residential and commercial customers, the volume of deliveries to other (*e.g.* industrial and power generation)

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[15] We gathered and processed 1999 data for Union but found that rapid productivity growth in the year 2000 seems to have reflected the tail end of the appliance-related downsizing.

[16] The X factor then requires, additionally, an average use adjustment, as discussed in Section 3.4.

[17] Details of the econometric cost research are provided in the Appendix.

[18] A larger sample is known to increase the precision of parameter estimates.

customers, and the number of customers served. Comments by Enbridge witnesses prompted us to consider, in our latest research, an index of transmission and distribution line miles. The need to include this variable in the model received strong statistical support. However, its inclusion required the consolidation of the two U.S. volume variables used in our econometric work into a single variable, total throughput.

All three of the resultant output variables included in the models were found to be statistically significant. Our research also suggests that economies of scale are substantial in the gas utility business and are an important source of productivity growth. At sample mean values of the business conditions, for instance, we find in each model that simultaneous 1% growth in all three output measures raises the total cost of service by about 0.89%.

The new models confirmed the results of our previous research that incremental returns to scale from output growth do not diminish markedly with size in the gas utility industry. This means that a company like Enbridge, which is large but still experiences rapid output growth, can still realize incremental scale economies that materially raise its TFP growth potential. However, we did not find as we did in the work for the June 20 report, a notable *increase* in returns to scale with size. This new result would tend to lower the expected TFP growth of a large company like Enbridge.

The econometric research also found the following additional business conditions to be statistically significant in both models.

- Cost was higher the higher was the price of capital services
- Cost was higher the higher was the price of labour
- Cost was higher the higher was the share of cast iron in the total miles of gas mains.
- Cost was lower the greater was the number of electric customers served
- Cost trended downward by between 1% and 1.2% annually for reasons other than changes in the specified business conditions. Since these estimates pertain to the cost model's trend variable parameter they are properly called parametric trend estimates. They are often construed as measures of the cost impact of technological change.

Some of these results proved useful in the selection of productivity targets for Enbridge and Union, as we discuss further below.

In developing the econometric cost models we had to deal with two problems that are common in econometric cost research: multicollinearity between the output variables and complexities in the distributions of the error terms of models equations (*e.g.* autocorrelation and heteroskedasticity). Both of these problems can potentially reduce the variance of parameter estimates around the true parameter values but do not cause them to be biased. As discussed further in the Appendix, we dealt with the multicollinearity in a way that is recommended in econometric textbooks: with a large panel data set.[20] This consisted of all of the good data on U.S. utility operations that are available. We believe the results for models estimated using subsets of data in which multicollinearity is more pronounced do not imply that our research is flawed. They indicate, instead, the extent of the "disease" before the "cure".

As for autocorrelation and heteroskedasticity, time constraints did not permit us to correct for both of these problems. We opted to control for heteroskedasticity, which is well known to be a problem with statistical cost research. The gravity of the autocorrelation problem is unknown. To the extent that there is a problem, however, it affects only the *variance* of parameter estimates and does not *bias* them.

3.3.3 Output Quantity Indexes

The trends in output quantity indexes were noted in Section 2.1 to be weighted averages of subindexes that measure trends in various output dimensions. Key issues in index design include the choice of subindexes and the basis for their weights. In our TFP research we used output indexes designed to measure the impact of output growth on cost. The elasticity weights are based, as noted above, on econometric elasticity estimates. There are three output subindexes: total throughput, a line miles variable, and the number of customers served.[21] The residential and commercial volume data for U.S. companies were weather normalized by PEG using heating degree days (HDDs) data from the U.S. government and estimates of the impact of HDDs on volumes that we developed

[20] Please see the Appendix Section A.6.4 for further discussion of this issue.

[21] Since the elasticity estimates were based on U.S. data, limitations of this data guided our choice of variables for the elasticity weighted output index.

econometrically. Since the release of the June 20 report we have revisited our weather normalization method out of concern that it generates results quite different from those of Enbridge. On the basis of this new work we have decided that the weather normalized volumes prepared by Union and Enbridge are the best available for their purpose and we use them to calculate TFP trends for these companies and in choosing their TFP targets.

In the research supporting the first draft of this report the index weights in the output indexes used in TFP research were the same for all US and Ontario utilities and reflected the estimated elasticities at sample mean values of the US business conditions. The resulting weights for residential and commercial volumes, other volumes, and the number of customers served were 15%, 11%, and 74% respectively. In the research for the June 20 report and this report we calculated output indexes using elasticity estimates that vary by company and reflect each company's special operating conditions. The sample mean values of the resultant elasticity shares in the new model with COS costing are about 68% for customers, 10% for throughput, and 22% for line miles.[22]

In constructing such indexes for Enbridge and Union we added to the weather normalized volumes estimates, based on company data, of their demand-side management ("DSM") savings since the start of the sample period. This treatment, combined with the exclusion of DSM expenses from cost, was undertaken in the hope that the PCIs will not compensate the utilities for their DSM activities. This compensation task is assumed to be left to other provisions of the regulatory system, such as the DSM and lost margin variance accounts.

We also computed output quantity indexes designed to measure the effect of growth in billing determinants (*e.g.* delivery volumes and contract demand) on *revenue*. The shares of each billing determinant in *revenue* served as weights in these indexes. Both Ontario utilities provided us with highly detailed data on billing determinants and the corresponding revenues. These data permitted us to develop revenue-weighted output quantity indexes of considerable sophistication. The detailed data that Union provided pertained to their actual output and revenue. Enbridge provided detailed data for actual output and for the revenue requirement approved by the Board in establishing rates. While the revenue shares for the

[22] The analogous shares for GD costing were very similar: 62% for customers, 13% for throughput, and 25% for line miles.

two companies are thus drawn from different sources we expect that both will yield satisfactory results.

The subindexes that we used to construct the revenue-weighted output quantity indexes for US utilities were: the volume of deliveries to residential and commercial customers, the volume of deliveries to other (*e.g.* industrial and generation) customers, and the number of customers served. Lacking US data on the corresponding revenue shares, we employed instead the average of the revenue shares for Union and Enbridge. These were: 52.5% for residential and commercial volumes, 17.4% for other volumes, and 30.1% for the number of customers.

A comparison of the weights for the elasticity and revenue-weighted output quantity indexes reveals that they are quite different. The number of customers served is the chief driver of gas utility *cost* whereas the volume of deliveries to residential and commercial customers is the chief *revenue* driver. The residential and commercial sectors account for more than 95% of customers served. Our research thus suggests that gas utility finances will be sensitive to change in the average use of residential and commercial customers. If use per customer declines, for example, cost is apt to grow more rapidly than revenue and utilities will find themselves in need of more rapid rate escalation.

An issue that arose in the course of the research was whether to allow the revenue weights in the output indexes to change over time to reflect any changes over the sample period in the share of revenue drawn from the various billing determinants. Revenue shares can change materially over time if companies make material changes in the design of their rates. Index theory suggests that indexes with flexible weights are generally more accurate. For this reason, they are often used in index research. The revenue shares of the rate elements (*e.g.* customer and volumetric chargers) of Enbridge and (especially) Union changed materially over the sample period, as an attempt was made to collect more revenue from customer charges. Since the number of customers grew more rapidly than delivery volumes, output indexes with flexible revenue weights tend to grow more rapidly than indexes with weights fixed in an early year of the sample period.

However, our research for Board staff is to support the design of PCIs and Staff has proposed that gas utilities not be allowed to redesign rates under the plan without explicit Board approval. We, accordingly, use output indexes in the calculation of AUs that have revenue weights fixed at levels commensurate with the 2007 test year.[23] These are more in keeping with the notion that rate designs will not change. Any redesign of rates during the sample period may require an adjustment in the X factor to achieve revenue neutrality. We estimate that the X factor for a price cap index should be raised by 6 basis points if ongoing rate redesign is allowed along the lines that has transpired since the year 2000[24].

3.3.4 Input Quantity Indexes

The trends in input (quantity) indexes were noted in Section 2.1 to be cost-share weighted averages of subindexes that measure trends in the use of various inputs. Our input indexes feature subindexes for three input categories: labour, M&S, and capital.

Quantity indexes for capital are discussed at length in section A.4 of the Appendix. Each quantity subindex for labour was calculated as the ratio of salary and wage expenses to a labour price index. For the Ontario utilities we used as a labour price deflator an Ontario construction worker salaries and wages index. This was chosen in part because the available Stats Canada indexes of utility salary and wage trends displayed implausibly slow growth over the sample period. An additional advantage of the construction worker compensation data is that data are available for *total* compensation as well as for *salaries and wages*.[25] The total compensation index is useful in the calculation of the input price differential, as we discuss further below.

For the US companies, National Compensation Survey ("NCS") data for 2004 were used to construct average wage rates that correspond to each distributor's service territory. Values for other years were calculated by adjusting the 2004 level for changes in employment cost trends. For this purpose, we used the employment cost index ("ECI") for electric, gas, and sanitary workers. Regional labour price trends were obtained by adjusting the trends in this national ECI for the difference in the trends of *comprehensive* regional and national ECIs. All of these ECIs are calculated by the U.S. Bureau of Labor Statistics.

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[23] This is not an issue in the design of a revenue per customer cap since there is no AU term in the X factor formula.

[24] This is the average difference between the growth trends in revenue-weighted output indexes for Enbridge and Union using year 2000 weights and flexible weights. This makes sense since the trend in the rates of utility is the difference between the trends in its revenue and a revenue-weighted output index. Thus, the rate trend would be 6 basis points slower on average using flexible weights than using the earlier fixed weights, before fixed charges were raised.

[25] Total compensation indexes are less widely available in Canada than in the United States.

Each quantity subindex for other O&M inputs was calculated as the ratio of the expenses for other O&M inputs to a non-labor O&M price index. For the US utilities we used the comprehensive chain-weighted gross domestic product price index. We have found that this index tracks the trend in utility materials and services rather well. For the Ontario utilities we used the comprehensive GDPIPI for Ontario.

3.3.5 Productivity Results

United States

Table 2 and Figure 1 report key results of our US TFP research. Findings are presented for the TFP index and the component output and input quantity indexes. The reported trends are size (specifically, cost) weighted averages of the trends for the 36 companies.[26] Using COS capital costing, it can be seen that over the full 1994-2004 sample period the average annual growth rate in the TFP of the sample was about 1.61%.[27] [28] Output growth averaged a 1.55% annual pace, whereas inputs averaged a slight -0.05% annual decline. Over the same period, the annual average growth rate in a federal government index of the trend in the multifactor productivity of the US private business sector was 1.33%.

We also calculated the productivity trend of the US utilities in use of O&M inputs. Using COS capital costing for the output index weights, their PFP indexes grew at a 2.41% average annual rate over the full sample period.[29] O&M inputs were thus typically a bright spot in the recent productivity experience of the sampled US utilities.

Table 3 presents some details of the input quantity trends of the sampled US utilities. It can be seen that the quantity trends of different kinds of inputs varied considerably. Using the COS approach to capital costing, the quantity of capital grew at a 0.49% annual pace that was well above that of the summary input quantity index.[30] Usage of O&M inputs thus grew at a considerably *slower* pace on balance. Use of labour declined materially whereas

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[26] Recall that we do not have base rate revenues for these companies.

[27] All growth trends noted in this report were computed logarithmically.

[28] This is a little more rapid than the 1.37% trend in the June 2007 report due, chiefly, to the lower weight on (slow growing) throughput and the higher weight on (more rapidly growing) line miles.

[29] The result was virtually the same using GD capital costing.

[30] Using the GD approach to capital costing, the growth trend in the capital quantity was modestly higher.

Table 2

PRODUCTIVITY RESULTS: US SAMPLE

Year	Output Quantity Index		Input Quantity Index		TFP Index		O&M PFP Index		MFP US Private
	Geometric Decay	COS	Geometric Decay	COS	Geometric Decay	COS	Geometric Decay	COS	Business Sector
1994	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	93.9
1995	1.019	1.019	1.004	1.001	1.015	1.018	1.028	1.028	93.7
1996	1.037	1.037	1.005	1.000	1.032	1.038	1.056	1.056	95.3
1997	1.056	1.056	0.989	0.982	1.067	1.076	1.131	1.131	96.2
1998	1.069	1.071	0.984	0.973	1.086	1.101	1.180	1.181	97.4
1999	1.088	1.091	0.987	0.976	1.102	1.118	1.202	1.203	98.7
2000	1.106	1.109	0.992	0.980	1.115	1.131	1.200	1.204	100.0
2001	1.120	1.126	0.990	0.978	1.132	1.151	1.241	1.247	100.2
2002	1.135	1.139	0.993	0.983	1.142	1.159	1.258	1.263	101.9
2003	1.151	1.155	1.003	0.991	1.148	1.165	1.265	1.269	104.6
2004	1.162	1.168	1.011	0.995	1.150	1.174	1.266	1.272	107.3
Average Annual Growth Rate **1994-2004**	**1.51%**	**1.55%**	**0.10%**	**-0.05%**	**1.40%**	**1.61%**	**2.36%**	**2.41%**	**1.33%**

FIGURE 1: TFP RESULTS FOR US SAMPLE

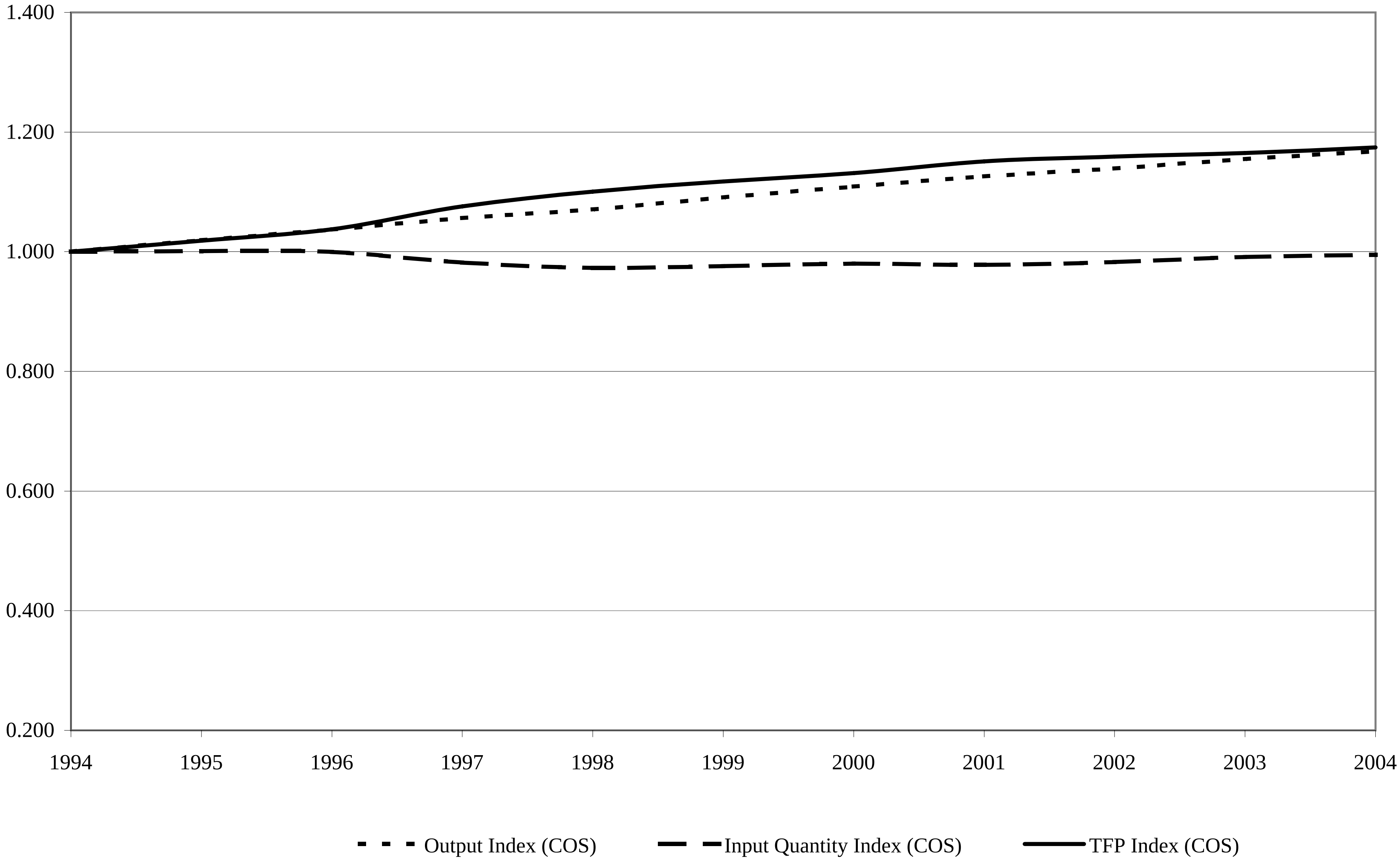

Table 3

INPUT QUANTITY INDEXES: US SAMPLE

Year	Summary Index: Geometric Decay	Summary Index: COS	Input Quantity Subindexes: Labor	Input Quantity Subindexes: Materials & Services	Input Quantity Subindexes: Capital - Geometric Decay	Input Quantity Subindexes: Capital - COS
1994	1.000	1.000	1.000	1.000	1.000	1.000
1995	1.004	1.001	0.907	1.132	1.012	1.009
1996	1.005	1.000	0.889	1.131	1.022	1.016
1997	0.989	0.982	0.869	1.038	1.030	1.023
1998	0.984	0.973	0.818	1.058	1.037	1.026
1999	0.987	0.976	0.818	1.064	1.041	1.030
2000	0.992	0.980	0.742	1.198	1.046	1.033
2001	0.990	0.978	0.687	1.261	1.049	1.037
2002	0.993	0.983	0.730	1.192	1.054	1.045
2003	1.003	0.991	0.732	1.215	1.062	1.051
2004	1.011	0.995	0.685	1.314	1.069	1.050
Average Annual Growth Rate **1994-2004**	**0.10%**	**-0.05%**	**-3.79%**	**2.73%**	**0.67%**	**0.49%**

use of materials and services rose briskly. These findings may reflect some substitution of M&S inputs for labour. It may also reflect greater reliance on the services of affiliated companies.

Table 4 presents some details of the output quantity trends of the sampled US utilities. It can be seen that the number of customers grew at a 1.67% average annual pace. The weather normalized deliveries of gas to residential and commercial customers averaged 0.61% annual growth. The average use of gas by residential and commercial customers thus fell by about 1% annually.[31] *Total* throughput fell by 0.25% annually. Line miles indexes grew by 1.51% annually. The addition of this variable to the elasticity-weighted output indexes thus serves to accelerate output growth.

We would expect on the basis of these results to find a substantial difference between the growth trends of the revenue and elasticity weighted output quantity indexes. Output indexes with fixed revenue weights grew in fact at a 0.28% average annual rate. Recalling the 1.55% average annual growth in the output index with elasticity weights, the resultant output quantity trend differential averaged -1.27%.[32]

Enbridge

Table 5 presents results of the TFP indexes for Enbridge and Union. Considering Enbridge first, we find using the COS approach to capital costing that its 0.60% average annual TFP growth from 2000 to 2006 was well below the US norm.[33] TFP declined a little in 2006. The 2.96% average annual pace of output growth was almost double the US norm. This reflects in large measure the brisk expansion of the Toronto and Ottawa metropolitan areas. Input quantity growth averaged 2.36% annually, also far above the U.S. average.

Tables 6 and 7 present some details of the input and output quantity trends of Enbridge. It can be seen that the input growth pattern was quite different from the US norm. The 1.59% trend in the capital quantity using COS costing was well below the trend in the summary input quantity index, instead of being modestly above it, as in the US case.

[31] The ratio of residential and commercial volumes to the total number of customers provides a good approximation of the trend in residential and commercial sector average.

[32] Recall that flexible revenue weights were not available for the U.S.

[33] The TFP index for Enbridge that we calculated using GD capital costing had a 0.46% average annual growth rate over the 2000-2006 period.

Table 4

OUTPUT QUANTITY INDEXES: US SAMPLE

	Summary Output			Quantity Subindexes				
	Cost Elasticity Weights		Fixed	Customer	Throughput			Line
Year	Geometric Decay	COS	Revenue Weights[1]	Numbers	Residential & Commercial[2]	Other	Total[3]	Miles
1994	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
1995	1.019	1.019	1.017	1.020	1.027	0.983	1.019	1.019
1996	1.037	1.037	1.019	1.038	1.029	0.959	1.014	1.037
1997	1.056	1.056	1.030	1.058	1.050	0.930	1.020	1.055
1998	1.069	1.071	1.012	1.076	1.027	0.872	0.987	1.072
1999	1.088	1.091	1.031	1.097	1.036	0.913	1.007	1.084
2000	1.106	1.109	1.050	1.116	1.056	0.932	1.051	1.098
2001	1.120	1.126	1.014	1.139	1.021	0.814	1.003	1.112
2002	1.135	1.139	1.033	1.150	1.044	0.831	0.987	1.131
2003	1.151	1.155	1.030	1.164	1.072	0.737	0.969	1.150
2004	1.162	1.168	1.029	1.182	1.063	0.737	0.975	1.163
Average Annual Growth Rate **1994-2004**	**1.51%**	**1.55%**	**0.28%**	**1.67%**	**0.61%**	**-3.05%**	**-0.25%**	**1.51%**

[1] The revenue weights are fixed at the Enbridge/Union averages for the 2007 test year. The revenue-weighted index includes customers.

[2] These volumes have been weather normalized.

[3] This is the sum of the weather normalized residential & commercial and other throughput.

Table 5

PRODUCTIVITY RESULTS: ONTARIO

Year	Output Quantity Index - Cost Elasticity				Input Quantity Index				TFP Index				O&M PFP Index	
	GD Capital Cost		COS Capital Cost		GD Capital Cost		COS Capital Cost		GD Capital Cost		COS Capital Cost		COS Weights	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**
2000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2001	1.014	1.020	1.017	1.025	1.007	1.031	1.009	1.030	1.006	0.990	1.008	0.994	1.003	0.958
2002	1.039	1.055	1.040	1.059	1.038	1.027	1.043	1.025	1.001	1.028	0.996	1.034	0.936	1.046
2003	1.053	1.088	1.057	1.094	1.027	1.075	1.021	1.076	1.025	1.012	1.034	1.017	0.993	0.943
2004	1.073	1.114	1.078	1.122	1.015	1.089	1.010	1.092	1.058	1.023	1.068	1.028	1.028	0.949
2005	1.093	1.152	1.098	1.159	1.002	1.101	1.001	1.112	1.091	1.046	1.097	1.043	1.065	0.971
2006	1.103	1.186	1.112	1.195	0.998	1.143	1.018	1.152	1.105	1.038	1.092	1.037	1.081	0.938
Average Annual Growth Rate														
2000-2005	**1.78%**	**2.83%**	**1.87%**	**2.95%**	**0.04%**	**1.92%**	**0.02%**	**2.12%**	**1.74%**	**0.91%**	**1.85%**	**0.83%**	**1.25%**	**-0.58%**
2000-2006	**1.63%**	**2.84%**	**1.77%**	**2.96%**	**-0.03%**	**2.22%**	**0.29%**	**2.36%**	**1.66%**	**0.62%**	**1.47%**	**0.60%**	**1.29%**	**-1.07%**

Table 6

INPUT QUANTITY INDEXES: ONTARIO

	Summary Input Quantity Indexes				Input Quantity Subindexes							
Year	GD Capital Cost		COS Capital Cost		Labour		Materials & Services		Capital: GD Capital Cost		Capital: COS Capital Cost	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**
2000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2001	1.007	1.031	1.009	1.030	0.999	1.009	1.034	1.099	1.004	1.017	1.007	1.015
2002	1.038	1.027	1.043	1.025	1.031	0.860	1.222	1.086	1.009	1.031	1.011	1.030
2003	1.027	1.075	1.021	1.076	1.006	0.801	1.145	1.333	1.012	1.045	1.001	1.041
2004	1.015	1.089	1.010	1.092	0.945	0.744	1.198	1.397	1.001	1.056	0.991	1.053
2005	1.002	1.101	1.001	1.112	0.971	0.782	1.112	1.394	0.990	1.068	0.987	1.078
2006	0.998	1.143	1.018	1.152	0.969	0.795	1.109	1.509	0.986	1.092	1.015	1.100
Average Annual Growth Rate												
2000-2005	**0.04%**	**1.92%**	**0.02%**	**2.12%**	**-0.58%**	**-4.93%**	**2.12%**	**6.64%**	**-0.19%**	**1.31%**	**-0.26%**	**1.50%**
2000-2006	**-0.03%**	**2.22%**	**0.29%**	**2.36%**	**-0.52%**	**-3.82%**	**1.72%**	**6.85%**	**-0.24%**	**1.47%**	**0.25%**	**1.59%**

Table 7

OUTPUT QUANTITY INDEXES: ONTARIO

	Summary Output Quantity Indexes										Output Quantity Subindexes[1]							
	Cost Elasticity Weighted				Revenue Weighted													
Year	**GD Capital Cost**		**COS Capital Cost**		**2007 Fixed Weights**		**Flexible Weights**		**2000 Fixed Weights**		**Customers**		**Line Mile Index**		**Residential & Commercial Volume**		**Other Volume**	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union[2]**	**Enbridge[3]**	**Union[2]**	**Enbridge[3]**	**Union**	**Enbridge**
2000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1,123,523	1,464,738	1.000	1.000	5,269	8,934	30,541	3,188
2001	1.014	1.020	1.017	1.025	0.991	0.995	0.985	0.992	0.985	0.991	1,146,376	1,519,039	1.016	1.005	5,239	8,777	27,677	2,934
2002	1.039	1.055	1.040	1.059	1.025	1.013	1.022	1.009	1.021	1.008	1,171,277	1,566,710	1.030	1.052	5,444	8,848	32,118	3,043
2003	1.053	1.088	1.057	1.094	1.030	1.032	1.019	1.026	1.018	1.025	1,195,115	1,622,016	1.041	1.083	5,336	9,010	30,152	3,044
2004	1.073	1.114	1.078	1.122	1.053	1.054	1.041	1.048	1.038	1.046	1,224,276	1,676,380	1.049	1.093	5,394	9,148	31,283	3,016
2005	1.093	1.152	1.098	1.159	1.058	1.095	1.044	1.089	1.041	1.087	1,248,510	1,724,716	1.061	1.145	5,463	9,557	32,791	2,925
2006	1.103	1.186	1.112	1.195	1.065	1.106	1.048	1.100	1.044	1.097	1,267,923	1,782,813	1.076	1.181	5,542	9,531	29,177	2,900
Average Annual Growth Rate																		
2000-2005	**1.78%**	**2.83%**	**1.87%**	**2.95%**	**1.13%**	**1.82%**	**0.86%**	**1.71%**	**0.80%**	**1.67%**	**2.11%**	**3.27%**	**1.19%**	**2.70%**	**0.72%**	**1.35%**	**1.42%**	**-1.72%**
2000-2006	**1.63%**	**2.84%**	**1.77%**	**2.96%**	**1.05%**	**1.68%**	**0.78%**	**1.59%**	**0.71%**	**1.54%**	**2.02%**	**3.28%**	**1.21%**	**2.77%**	**0.84%**	**1.08%**	**-0.76%**	**-1.58%**

[1]These subindexes are used in the elasticity weighted output indexes

[2]Residential and commercial volume (Rates M2, 01, and 10) was weather normalized.

[3]Includes rates 1, 6, 100. Rates 1, 6 was weather normalized

Union

Table 5 reveals that the TFP growth of Union using COS costing averaged 1.47% growth per annum, modestly below the US sample average. Union's TFP declined a little in 2006 due, in part, to a major expansion of the transmission system which coincided with a weather-related downturn in transmission volume.[34] The 1.77% average annual pace of output growth was well below that of Enbridge but a little above the US norm. Input use was virtually unchanged, with a 0.29% average annual pace of input index growth that was similar to the US trend. The TFP index for Union that we calculated using GD capital costing exhibited 1.66% average annual growth over the 2000-2006 period. Table 6 shows that the slow growth in input usage (using COS costing) was due to a -0.52% average annual decline in the use of labour and 0.25% growth in the use of capital. A side calculation revealed that the trends in the quantities of capital used in distribution and transmission are fairly similar. This suggests that Union's TFP growth isn't markedly higher than that of Enbridge due to an extraordinary decline in Union's transmission rate base.

Productivity Differentials

A productivity differential was noted in Section 2 to be the difference between the trends in the productivity growth of the utility industry and the economy. The productivity trend of the industry in such a calculation is conventionally based largely or entirely on the productivity index trends of other utilities. This is often computed using the productivity trends of utilities in the same region as the subject utility.[35] This approach isn't feasible in the case of Enbridge and Union, for several reasons.

- Enbridge and Union face rather different operating challenges.
- Data are not readily available that would enable us to calculate the TFP trends of other Canadian gas utilities, such as Terasen Gas and Gaz Metropolitaine.
- Gas utilities in nearby areas of the United States (*e.g.,* Michigan, northern Ohio, and upstate New York) have a considerably different operating environment that usually includes slow demand growth.

[34] The transmission volumes in our TFP index for Union are not weather normalized.

[35] The X factor in the price cap index for Boston Gas, for instance, is based on the productivity trend of the gas distributors in the northeast United States.

Research of two kinds was accordingly undertaken, using US data, to assess the normal pace of TFP growth for companies facing the business conditions of Union and Enbridge. Both approaches made use of our mathematical analysis of the sources of TFP growth. This analysis, which is well established in the literature, is set forth in Section A-8 of the Appendix. This analysis, together with our econometric cost research, revealed that the realization of scale economies is the chief source of differences in the TFP trends of gas utilities. One approach to using this result was to calculate the average TFP index trends of peer groups consisting of companies with opportunities to realize incremental scale economies that are similar to those facing Enbridge and Union. The opportunity for a gas distributor to realize scale economies depends on the pace of its output growth and on the incremental scale economies that can result from output growth.

Results of this peer group analysis for the GD and COS approaches to capital costing are reported for Enbridge and Union in Tables 8a and 8b and 9a and 9b, respectively. Each table contains TFP index trends and an econometrically-based estimate of the scale economy effect for each sampled US utilities. Results for the peer group companies are shaded. Over the full 1994-2004 sample period it can be seen that the Enbridge peer group averaged 1.95% TFP growth using COS capital costing and 1.80% using GD costing. Notice that, with the addition of line miles as a business condition and the resultant elimination of the increasing returns to scale finding of the June 20 report, it is easier to identify a suitable peer group.[36] Most of the Enbridge peers were, like Enbridge, companies enjoying rapid customer growth. The Union peer group averaged 1.84% TFP growth using COS capital costing and 1.32% using GD costing.

The TFP index trends of the individual utilities support some key findings of our econometric research. For example, the fact that the TFP trends of companies with outsized scale economy potential were well above the US sample average supports our econometric finding that scale economies are an important source of TFP growth.

Our second approach to establishing TFP targets for Enbridge and Union was to calculate the TFP growth that can be predicted on the basis of econometric results and the mathematical theory of TFP growth drivers. In this exercise, we assigned each company the estimated rate of technical change from the appropriate econometric model. We then added

[36] The selection of peer groups for Union was not a problem using the June 20 models.

Table 8a

CHOOSING TFP PEERS FOR ENBRIDGE: GEOMETRIC DECAY

		Estimated Scale Effect		
Company	**TFP**	Company	vs. Enbridge	Peer
Arithmetic Sample Average [fn]	1.28%	0.17%	-0.15%	
Peer Average	**1.80%**	**0.30%**	**-0.02%**	
Enbridge	0.62%	0.32%		
Cascade Natural Gas	**2.70%**	0.45%	0.13%	1
Southwest Gas	**2.59%**	0.35%	0.03%	1
Washington Gas Light	**2.31%**	0.31%	-0.01%	1
Northwest Natural Gas	**1.99%**	0.30%	-0.02%	1
Public Service of NC	**0.70%**	0.29%	-0.03%	1
Madison Gas & Electric	**1.10%**	0.28%	-0.04%	1
Washington Natural Gas	**1.03%**	0.27%	-0.04%	1
Mountain Fuel Supply	**2.11%**	0.25%	-0.07%	1
Baltimore Gas and Electric	**1.79%**	0.24%	-0.08%	1
New Jersey Natural	**1.67%**	0.23%	-0.08%	1
Central Hudson Gas & Electric	**1.94%**	0.20%	-0.12%	
North Shore Gas	**2.17%**	0.20%	-0.12%	
San Diego Gas & Electric	**-0.45%**	0.20%	-0.12%	
PECO	**1.10%**	0.19%	-0.13%	
Wisconsin Power & Light	**1.63%**	0.19%	-0.13%	
Orange and Rockland	**-0.83%**	0.16%	-0.15%	
Louisville Gas & Electric	**0.35%**	0.16%	-0.15%	
PG Energy	**1.13%**	0.16%	-0.16%	
Wisconsin Gas	**1.95%**	0.16%	-0.16%	
Consumers Power	**0.77%**	0.16%	-0.16%	
Northern Illinois Gas	**1.16%**	0.14%	-0.18%	
Connecticut Energy	**1.00%**	0.14%	-0.18%	
Nstar Gas	**2.40%**	0.14%	-0.18%	
Public Service Electric & Gas	**-0.08%**	0.13%	-0.19%	
Atlanta Gas Light	**1.57%**	0.13%	-0.19%	
Pacific Gas & Electric	**2.20%**	0.12%	-0.20%	
Consolidated Edison	**1.11%**	0.11%	-0.21%	
East Ohio Gas	**2.31%**	0.10%	-0.22%	
Niagara Mohawk	**1.48%**	0.10%	-0.22%	
Southern California Gas	**1.51%**	0.09%	-0.22%	
Rochester Gas and Electric	**0.91%**	0.07%	-0.25%	
Alabama Gas	**-1.57%**	0.06%	-0.26%	
Illinois Power	**2.39%**	0.03%	-0.29%	
People's Natural Gas	**0.63%**	0.03%	-0.29%	
Connecticut Natural Gas	**0.53%**	0.00%	-0.32%	
Peoples Gas Light & Coke	**0.71%**	-0.05%	-0.37%	

[fn] Average TFP trend will differ from that based on a size-weighted average of the company results.

Table 8b

CHOOSING TFP PEERS FOR ENBRIDGE: COS

Company	TFP	Estimated Scale Effect Company	Estimated Scale Effect vs. Enbridge	Peer
Arithmetic Sample Average [fn]	1.49%	0.19%	-0.17%	
Peer Average	**1.95%**	**0.35%**	**-0.01%**	
Enbridge	0.60%	0.36%		
Cascade Natural Gas	**2.80%**	0.50%	0.14%	1
Southwest Gas	**2.92%**	0.49%	0.14%	1
Northwest Natural Gas	**2.15%**	0.43%	0.07%	1
Public Service of NC	**0.71%**	0.37%	0.02%	1
Washington Natural Gas	**1.07%**	0.34%	-0.01%	1
Mountain Fuel Supply	**2.37%**	0.33%	-0.03%	1
Washington Gas Light	**2.57%**	0.31%	-0.04%	1
Madison Gas & Electric	**1.37%**	0.27%	-0.09%	1
New Jersey Natural	**1.66%**	0.25%	-0.11%	1
Wisconsin Power & Light	**1.91%**	0.21%	-0.14%	1
Baltimore Gas and Electric	**2.41%**	0.20%	-0.15%	
Consumers Power	**1.06%**	0.20%	-0.16%	
PECO	**1.43%**	0.20%	-0.16%	
Atlanta Gas Light	**1.69%**	0.19%	-0.16%	
Northern Illinois Gas	**1.53%**	0.19%	-0.17%	
Wisconsin Gas	**2.17%**	0.18%	-0.17%	
North Shore Gas	**2.34%**	0.17%	-0.18%	
Central Hudson Gas & Electric	**1.85%**	0.17%	-0.19%	
San Diego Gas & Electric	**-0.35%**	0.17%	-0.19%	
Louisville Gas & Electric	**0.74%**	0.16%	-0.19%	
PG Energy	**1.42%**	0.15%	-0.20%	
Pacific Gas & Electric	**2.26%**	0.14%	-0.21%	
Orange and Rockland	**-0.96%**	0.14%	-0.22%	
Public Service Electric & Gas	**-0.01%**	0.14%	-0.22%	
East Ohio Gas	**2.66%**	0.13%	-0.22%	
Southern California Gas	**1.70%**	0.12%	-0.23%	
Connecticut Energy	**1.20%**	0.11%	-0.24%	
Niagara Mohawk	**2.08%**	0.11%	-0.24%	
Nstar Gas	**2.43%**	0.11%	-0.24%	
Alabama Gas	**-1.57%**	0.07%	-0.28%	
Rochester Gas and Electric	**1.05%**	0.07%	-0.28%	
Consolidated Edison	**1.13%**	0.05%	-0.30%	
Illinois Power	**2.84%**	0.05%	-0.31%	
People's Natural Gas	**1.01%**	0.04%	-0.31%	
Connecticut Natural Gas	**0.99%**	0.02%	-0.34%	
Peoples Gas Light & Coke	**1.09%**	-0.03%	-0.38%	

[fn] Average TFP trend will differ from that based on a size-weighted average of the company results.

Table 9a

CHOOSING TFP PEERS FOR UNION: GEOMETRIC DECAY

Company	TFP	Estimated Scale Effect: Company	Estimated Scale Effect: vs. Union	Peer
Arithmetic Sample Average [fn]	1.28%	0.17%	-0.07%	
Peer Average	**1.32%**	**0.24%**	**0.00%**	
Union	1.66%	0.24%		
Cascade Natural Gas	**2.70%**	0.45%	0.21%	
Southwest Gas	**2.59%**	0.35%	0.11%	
Washington Gas Light	**2.31%**	0.31%	0.07%	
Northwest Natural Gas	**1.99%**	0.30%	0.06%	
Public Service of NC	**0.70%**	0.29%	0.05%	1
Madison Gas & Electric	**1.10%**	0.28%	0.04%	1
Washington Natural Gas	**1.03%**	0.27%	0.04%	1
Mountain Fuel Supply	**2.11%**	0.25%	0.01%	1
Baltimore Gas and Electric	**1.79%**	0.24%	0.00%	1
New Jersey Natural	**1.67%**	0.23%	0.00%	1
Central Hudson Gas & Electric	**1.94%**	0.20%	-0.04%	1
North Shore Gas	**2.17%**	0.20%	-0.04%	1
San Diego Gas & Electric	**-0.45%**	0.20%	-0.04%	1
PECO	**1.10%**	0.19%	-0.05%	1
Wisconsin Power & Light	**1.63%**	0.19%	-0.05%	
Orange and Rockland	**-0.83%**	0.16%	-0.07%	
Louisville Gas & Electric	**0.35%**	0.16%	-0.07%	
PG Energy	**1.13%**	0.16%	-0.08%	
Wisconsin Gas	**1.95%**	0.16%	-0.08%	
Consumers Power	**0.77%**	0.16%	-0.08%	
Northern Illinois Gas	**1.16%**	0.14%	-0.10%	
Connecticut Energy	**1.00%**	0.14%	-0.10%	
Nstar Gas	**2.40%**	0.14%	-0.10%	
Public Service Electric & Gas	**-0.08%**	0.13%	-0.11%	
Atlanta Gas Light	**1.57%**	0.13%	-0.11%	
Pacific Gas & Electric	**2.20%**	0.12%	-0.12%	
Consolidated Edison	**1.11%**	0.11%	-0.13%	
East Ohio Gas	**2.31%**	0.10%	-0.14%	
Niagara Mohawk	**1.48%**	0.10%	-0.14%	
Southern California Gas	**1.51%**	0.09%	-0.14%	
Rochester Gas and Electric	**0.91%**	0.07%	-0.17%	
Alabama Gas	**-1.57%**	0.06%	-0.18%	
Illinois Power	**2.39%**	0.03%	-0.21%	
People's Natural Gas	**0.63%**	0.03%	-0.21%	
Connecticut Natural Gas	**0.53%**	0.00%	-0.24%	
Peoples Gas Light & Coke	**0.71%**	-0.05%	-0.29%	

[fn] Average TFP trend will differ from that based on a size-weighted average of the company results.

Table 9b

CHOOSING TFP PEERS FOR UNION: COS

Company	TFP	Estimated Scale Effect: Company	Estimated Scale Effect: vs. Union	Peer
Arithmetic Sample Average [fn]	1.49%	0.19%	-0.120%	
Peer Average	**1.84%**	**0.31%**	**0.00%**	
Union	1.47%	0.31%		
Cascade Natural Gas	**2.80%**	0.50%	0.19%	
Southwest Gas	**2.92%**	0.49%	0.18%	1
Northwest Natural Gas	**2.15%**	0.43%	0.12%	1
Public Service of NC	**0.71%**	0.37%	0.07%	1
Washington Natural Gas	**1.07%**	0.34%	0.04%	1
Mountain Fuel Supply	**2.37%**	0.33%	0.02%	1
Washington Gas Light	**2.57%**	0.31%	0.00%	1
Madison Gas & Electric	**1.37%**	0.27%	-0.04%	1
New Jersey Natural	**1.66%**	0.25%	-0.06%	1
Wisconsin Power & Light	**1.91%**	0.21%	-0.09%	1
Baltimore Gas and Electric	**2.41%**	0.20%	-0.10%	1
Consumers Power	**1.06%**	0.20%	-0.11%	1
PECO	**1.43%**	0.20%	-0.11%	
Atlanta Gas Light	**1.69%**	0.19%	-0.11%	
Northern Illinois Gas	**1.53%**	0.19%	-0.12%	
Wisconsin Gas	**2.17%**	0.18%	-0.12%	
North Shore Gas	**2.34%**	0.17%	-0.13%	
Central Hudson Gas & Electric	**1.85%**	0.17%	-0.14%	
San Diego Gas & Electric	**-0.35%**	0.17%	-0.14%	
Louisville Gas & Electric	**0.74%**	0.16%	-0.15%	
PG Energy	**1.42%**	0.15%	-0.15%	
Pacific Gas & Electric	**2.26%**	0.14%	-0.16%	
Orange and Rockland	**-0.96%**	0.14%	-0.17%	
Public Service Electric & Gas	**-0.01%**	0.14%	-0.17%	
East Ohio Gas	**2.66%**	0.13%	-0.18%	
Southern California Gas	**1.70%**	0.12%	-0.19%	
Connecticut Energy	**1.20%**	0.11%	-0.19%	
Niagara Mohawk	**2.08%**	0.11%	-0.20%	
Nstar Gas	**2.43%**	0.11%	-0.20%	
Alabama Gas	**-1.57%**	0.07%	-0.23%	
Rochester Gas and Electric	**1.05%**	0.07%	-0.24%	
Consolidated Edison	**1.13%**	0.05%	-0.26%	
Illinois Power	**2.84%**	0.05%	-0.26%	
People's Natural Gas	**1.01%**	0.04%	-0.27%	
Connecticut Natural Gas	**0.99%**	0.02%	-0.29%	
Peoples Gas Light & Coke	**1.09%**	-0.03%	-0.34%	

[fn] Average TFP trend will differ from that based on a size-weighted average of the company results.

this to each company's estimated scale effect resulting from the growth in their output during the sample period. This depends on the availability of incremental scale economies from growth in output and on the trend in output growth. Following mathematical theory, we measure the opportunity for incremental scale economies of each company as 1 minus the sum of the econometric estimates of its estimated output elasticities. We measure output growth as the average annual growth in each company's weather normalized, elasticity-weighted output index from 2000 to 2006. The expected scale effects are the product of these two terms. Results of this analysis are reported in Table 10. It can be seen that using COS capital costing the TFP trend targets for Enbridge and Union are 1.54% and 1.50% respectively.[37] Numbers are a little lower using GD costing (1.27% for Enbridge and 1.20% for Union) due, chiefly, to a lower estimate of technological change.

In comparing the suitability of these methods, we find that the econometric approach is less sensitive to the random variations in the TFP trends of the (perforce rather small) peer groups. On the other hand, the econometric model reflects the adjustment of cost to changing business conditions in the longer run. Econometric projections are also more sensitive to important changes in the cost model and its estimation procedure. Moreover, a suitable peer group for Enbridge was less difficult to establish with the new econometric model than with the models used in the 20 June report. Parties may find it useful to take a look at the peers that are used in the calculations. In the present exercise, these are generally companies with rapid output growth. Some peers are smaller than Enbridge and Union, but that is because our research shows that the opportunities to realize economies do not diminish markedly with scale. The opportunity to realize scale economies relies mainly on output growth. We therefore recommend the use of the peer groups to establish the TFP targets of both companies. Using the COS approach to capital costing, the resultant targets are thus 1.95% for Enbridge and 1.84% for Union.

It is noteworthy that the target for Enbridge is well above its recent historical trend. One theory that fits these facts is that the frequent rate cases of Enbridge produced unusually weak performance incentives. However, deviations from the TFP norm can result from many sources in a sample period as short as seven years.

[37] These numbers are much lower than the 2.10% and 1.73% numbers reported previously.

Table 10

TFP GROWTH PROJECTIONS FROM ECONOMETRIC RESEARCH

	Geometric Decay Capital Costing		COS Capital Costing	
	Enbridge	**Union**	**Enbridge**	**Union**
Sample Years	2000-2006	2000-2006	2000-2006	2000-2006
Elasticity Estimates				
Customers [A]	0.537	0.540	0.616	0.606
Total Deliveries [B]	0.091	0.043	0.060	0.017
Line Miles [C]	0.260	0.271	0.204	0.203
Sum of Output Elasticities [D=A+B+C]	0.888	0.854	0.880	0.826
Output Index Weights				
Customers [E=A/(A+B+C)]	60.47%	63.23%	70.00%	73.37%
Total Deliveries [F=B/(A+B+C)]	10.25%	5.04%	6.82%	2.06%
Line Miles [G=C/(A+B+C)]	29.28%	31.73%	23.18%	24.58%
Subindex Growth				
Customer [H]	3.25%	2.02%	3.25%	2.02%
Total Delivery [I]	-0.12%	-0.91%	-0.12%	-0.91%
Line Miles [J]	2.77%	1.41%	2.77%	1.41%
Output Growth (elasticity weighted) [K=E*H+F*I+G*J]	2.77%	1.68%	2.91%	1.81%
Returns to Scale [L=(1-D)*K]	**0.31%**	**0.24%**	**0.35%**	**0.31%**
Technological Change [M]	**0.96%**	**0.96%**	**1.19%**	**1.19%**
TFP Projection [L + M]	**1.27%**	**1.20%**	**1.54%**	**1.50%**

The econometric models also provide us with an estimate of the effect of cast iron replacement on TFP growth. This could potentially be added to the econometric TFP trend target for Enbridge since it has been reducing the amount of cast iron on its system in recent years and expects to accelerate the replacement during the IR plan term. As discussed in Section 3.3.2, we found that cast iron mains *raise* total cost. This finding implies that a reduction in cast iron *accelerates* TFP growth in the *long* run. However, the *short* and medium term effect on TFP growth may be different since the O&M cost savings may be offset initially by the cost impact of the installation of new pipe. As an extra check, we therefore regressed the growth in the TFP of our sampled US utilities on the change in their cast iron reliance using data for the sample period. Using each approach to TFP capital costing, the estimated effect of reduced cast iron reliance on cost was found to be statistically insignificant.

The productivity differentials that follow from these recommendations depend on the productivity growth trend for the Canadian economy that is used in the input price comparison. As discussed further in Section 3.5 below, we found the average of 1997-2006 and 1998-2006 to be a sensible input price comparison period. The Statistics Canada estimate of the MFP trend of the Canadian private business sector was 0.47% during this period.[38] The indicated productivity differential for Enbridge using COS capital costing is thus 1.48% (1.95 – 0.47). The productivity differential for Union is thus 1.37% (1.84 – 0.47).

3.4 Average Use Factor

Tables 11a and 11b present details of the average use of gas by the residential and commercial customers of Enbridge and Union. We present, for each company, the actual volumes per customer for the period 2000-2006 by service class as well as weather normalized treatments.

Inspecting the tables, it is evident that there were material declines in average use for all of the main rate classes that include residential customers. The problem is worst for Enbridge Rate 1, which is the only rate with a purely residential load.

[38] This reflects a recent and remarkably large downward revision in the growth of the index. Please note, however, that the X factor results for Union and Enbridge are unaffected.

Table 11a

Volume Per Customer Trends: Enbridge

Rate 1 (Residential)

Year	Volumes ($10^6 m^3$)			Customers		Volume Per Customer			
	Actual	Approved Rate Case Forecast	Normalized	Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized	Enbridge Stakeholder Presentation
	[A]	[B]	[C]	[D]	[E]	1000*[A]/[D]	[B]/[E]	1000*[C]/[D]	
2000	4,008	4,266	4,283	1,325,938	1,328,659	3.023	3.211	3.230	3,043
2001	4,228	4,163	4,147	1,377,459	1,373,517	3.070	3.031	3.010	2,940
2002	4,002	4,204	4,233	1,423,525	1,418,180	2.812	2.964	2.973	2,929
2003	4,735	4,242	4,242	1,476,603	1,468,966	3.207	2.888	2.873	2,900
2004	4,596	4,242	4,342	1,529,297	1,468,966	3.006	2.888	2.839	2,850
2005	4,620	4,627	4,548	1,575,322	1,568,544	2.932	2.950	2.887	2,779
2006	4,328	4,674	4,553	1,630,236	1,642,513	2.655	2.846	2.793	N/A
2000-2005	**2.84%**	**1.62%**	**1.20%**	**3.45%**	**3.32%**	**-0.61%**	**-1.70%**	**-2.25%**	**-1.82%**
2000-2006	**1.28%**	**1.52%**	**1.02%**	**3.44%**	**3.53%**	**-2.16%**	**-2.01%**	**-2.43%**	**N/A**

Rate 6 (General Service)

Year	Volumes ($10^6 m^3$)			Customers		Volume Per Customer			
	Actual	Approved Rate Case Forecast	Normalized	Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized	Enbridge Stakeholder Presentation
	[A]	[B]	[C]	[D]	[E]	1000*[A]/[D]	[B]/[E]	1000*[C]/[D]	
2000	2,999	3,176	3,219	136,025	138,575	22.050	22.918	23.663	22,138
2001	3,200	3,148	3,139	138,779	138,443	23.058	22.741	22.619	21,930
2002	2,932	3,201	3,110	140,351	144,102	20.888	22.212	22.156	21,785
2003	3,485	3,120	3,095	142,656	143,293	24.430	21.773	21.694	21,816
2004	3,314	3,120	3,110	144,331	143,293	22.959	21.773	21.548	21,527
2005	3,327	3,324	3,271	146,672	147,475	22.681	22.542	22.301	21,131
2006	3,160	3,249	3,346	150,038	147,356	21.059	22.050	22.300	N/A
2000-2005	**2.07%**	**0.91%**	**0.32%**	**1.51%**	**1.25%**	**0.56%**	**-0.33%**	**-1.19%**	**-0.93%**
2000-2006	**0.87%**	**0.38%**	**0.65%**	**1.63%**	**1.02%**	**-0.77%**	**-0.64%**	**-0.99%**	**N/A**

Table 11b

Volume Per Customer Trends: Union

Rate M2: General Service South

(55% of 2005 volume residential; 77% of total 2005 residential volume)

Year	Volumes ($10^6 m^3$)		Customers	Volume Per Customer [1]		
	Actual	Normalized	Actual	Actual	Normalized	Union Stakeholder Presentation Weather Normalized[2]
	[A]	[B]	[C]	1000*[A]/[C]	1000*[B]/[C]	
1999	3,748		836,601			NA
2000	3,898	3,897	848,719	4.593	4.592	NA
2001	3,668	3,902	869,021	4.221	4.490	4.577
2002	3,911	4,054	890,233	4.393	4.554	4.600
2003	4,164	3,948	911,282	4.569	4.332	4.521
2004	3,945	3,976	935,557	4.217	4.250	4.334
2005	4,028	4,015	956,004	4.213	4.200	4.255
2006	3,672	4,069	972,180	3.777	4.185	N/A
2000-2005[3]	**0.66%**	**0.60%**	**2.38%**	**-1.72%**	**-1.78%**	**-1.82%**
2000-2006	**-1.00%**	**0.72%**	**2.26%**	**-3.26%**	**-1.54%**	**N/A**

Rate 01: General Service North + East

(76% of 2005 volume residential; 23% of total 2005 residential volume)

Year	Volumes ($10^6 m^3$)		Customers	Volume Per Customer [1]		
	Actual	Normalized	Actual	Actual	Normalized	Union Stakeholder Presentation Weather Normalized[2]
	[A]	[B]	[C]	1000*[A]/[C]	1000*[B]/[C]	
1999	844		263,686			NA
2000	945	959	271,537	3.480	3.532	NA
2001	855	932	274,087	3.119	3.400	3.183
2002	912	939	277,588	3.285	3.383	3.371
2003	957	921	280,373	3.413	3.285	3.400
2004	919	926	285,201	3.222	3.247	3.243
2005	886	921	288,801	3.068	3.189	3.179
2006	804	902	292,070	2.753	3.088	N/A
2000-2005	**-1.29%**	**-0.81%**	**1.23%**	**-2.52%**	**-2.04%**	**-0.03%**
2000-2006	**-2.69%**	**-1.02%**	**1.21%**	**-3.91%**	**-2.24%**	**N/A**

Rate 10: (General Service North + East)

(0% of 2005 volume residential, 66% commercial)

Year	Volumes ($10^6 m^3$)		Customers	Volume Per Customer [1]		
	Actual	Normalized	Actual	Actual	Normalized	Union Stakeholder Presentation Weather Normalized[2]
	[A]	[B]	[C]	1000*[A]/[C]	1000*[B]/[C]	
1999	355					NA
2000	386	396	2,631	146.712	150.513	NA
2001	348	367	2,632	132.219	139.438	139.389
2002	382	387	2,841	134.460	136.220	141.009
2003	394	380	2,842	138.635	133.709	137.048
2004	384	384	2,914	131.778	131.778	132.534
2005	385	397	3,114	123.635	127.489	129.503
2006	364	400	3,137	116.034	127.510	N/A
2000-2005	**-0.05%**	**0.05%**	**3.37%**	**-3.42%**	**-3.32%**	**-1.84%**
2000-2006	**-0.98%**	**0.17%**	**2.93%**	**-3.91%**	**-2.76%**	**N/A**

[1]All ratios were calculated using the actual customer data except for the forecasted ratio which used the forecasted customers

[2]The weather normalization used for the stakeholder presentation is slightly different than the volume data provided previously.

The average use factor was explained in Section 2 to be the difference between the growth trends in the output quantity indexes with revenue and elasticity weights. For Enbridge and Union, the output growth differentials using 2007 revenue weights and COS capital costing to calculate elasticities weights were -1.28% (1.68-2.96) and -0.72% (1.05-1.77) respectively.[41] [42] The AU for Enbridge is thus considerably more negative than that for Union, as we might expect given its greater reliance on general service loads. Results were very similar using GD costing.

3.5 Input Price Research

Input price indexes are required in the calculation of IPDs. The trend in an input price index was noted in Section 2.1.3 to be a cost share weighted average of the growth in subindexes that measure inflation in the prices of certain groups of inputs. Major decisions in the design of such indexes include the choice of input categories and price subindexes.

3.5.1 Input Price Subindexes and Costs

Applicable total cost was divided into the same input categories used in the development of the input quantity index. The cost share weights were modestly different from those in the input *quantity* indexes used to calculate TFP because all taxes were removed from the cost of capital. We thereby assume, effectively, that the price corresponding to taxes rises at the average rate of all of the other prices.[43]

In the input price trend comparisons, the price subindex for labour was a Stats Canada index of Ontario construction worker *total* compensation. The price subindex for other O&M inputs was the Ontario GDPIPI for all goods and services. The capital price subindex was constructed from data on construction cost trends and the rate of return. The rate of return was an average of Stats Canada indexes for long term corporate bond yields and the return on equity of Canada utilities. [44]

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[41] The analogous result for our U.S. sample is -1.25. While this might suggest a more serious average use problem in the States, this calculation is not made with the same precision due to data limitations.

[42] Results were very similar using GD capital costing, as we might expect since this affects only the elasticity weights on one of the indexes.

[43] Note that this price is a function of the trend in construction costs as well as the trend in tax rates.

[44] In the previous version of the report we employed a 65/35 split.

The construction cost index employed in the preliminary study reflected trends in the United States. Following suggestions made last spring by a Union Gas consultant, we have used in the revised work the Stats Canada deflator for its gas distribution capital stock. This use of this index is supported by the available data.

3.5.2 Input Price Differentials

An IPD was noted in section 2 to be the difference between the input price trends of the economy and the industry. This is commonly computed by taking the difference between the trends over some sample period. It is not necessary to use the same sample periods for the IPD and PD calculations. That is because a given sample period may not be suitable for capturing the long run trends of both input price and productivity indexes.

The determination of appropriate IPDs for an IR plan beginning in 2008 is complicated by recent developments in markets for gas utility inputs. The cost of gas utility construction rose at a brisk pace in 2004 and 2005 due, chiefly, to a run-up in world market prices of steel and polyvinyl chloride, the materials used to make most gas utility piping. The impact of these developments on gas utility cost was, to some degree, offset by a lower weighted average rate of return (ROR) in 2005 and 2006.

An input price index calculated using the GD approach to capital costing is much more sensitive to these developments than one calculated using COS. That is because the GD capital service price trend depends on the *real* rather than the *nominal* rate of return. The real rate of return is the difference between the nominal rate of return and the growth rate in the asset price. The real rate of return can fluctuate considerably if the cost of funds does not rise when the asset price index does. Because of this problem it is customary to smooth the growth in the real rate of return when calculating a GD service price index. PEG commonly does this by taking a three year moving average of the real rate of return when it calculates the service price.

Details of the calculation of the capital service price index using GD costing are reported in Table 12 and Figures 2 & 3. In these and other tables in this section, index values that have been added since the June report or have been revised by Canadian agencies appear in gray. It can be seen that following five years of sluggish growth, the Statistics Canada capital stock deflator that we used to measure the asset price inflation grew by over

Table 12

Capital Service Price Index: Geometric Decay Capital Cost[0]

Year	Rate of Return						Asset Price		Real Rate of Return				Depreciation Rate[6]	Capital Service Price Indexes			
	Corporate Long Term Bond Yield		Return on Equity[3]		Weighted Average Rate of Return				Unsmoothed		Smoothed			Unsmoothed		Real Rate Smoothed	
	Level[1]	Growth Rate[2]	All companies	Utilities	Level[4]	Growth Rate[2]	Level[5]	Growth Rate[2]	Level	Growth Rate[2]	Level	Growth Rate[2]		Level	Growth Rate[2]	Level	Growth Rate[2]
	[A]	(%)		[B]	[C] = (.64*A+.36*B)	(%)	[D]	$[E]=\frac{(D_t-D_{(t-1)})}{D_{(t-1)}}$	[F]=C-E	(%)	[G]=3 Year Moving Average of [F]	(%)	[H]	$[I]=F*D_{(t-1)}+H*D_t$	(%)	$[J]=D_{(t-1)}*G+H*D_t$	(%)
1988	10.93%		12.70%	6.44%	9.32%		0.821		9.3%				3.7%	0.1042			
1989	10.81%	-1.1	11.51%	5.48%	8.89%	-4.7	0.846	3.0%	5.9%	-46.2			3.7%	0.0795	-27.0		
1990	11.91%	9.7	7.59%	4.20%	9.13%	2.7	0.852	0.8%	8.3%	35.3	7.8%		3.7%	0.1022	25.1	0.0980	
1991	10.80%	-9.7	3.87%	3.53%	8.18%	-11.0	0.870	2.0%	6.1%	-30.8	6.8%	-14.5	3.7%	0.0846	-19.0	0.0901	-8.4
1992	9.90%	-8.8	1.68%	5.96%	8.48%	3.5	0.886	1.9%	6.6%	7.5	7.0%	3.6	3.7%	0.0904	6.6	0.0940	4.3
1993	8.85%	-11.2	3.82%	6.25%	7.91%	-6.9	0.904	2.0%	5.9%	-11.0	6.2%	-12.2	3.7%	0.0860	-4.9	0.0887	-5.9
1994	9.44%	6.5	6.69%	5.91%	8.17%	3.2	0.937	3.7%	4.4%	-29.2	5.7%	-9.6	3.7%	0.0747	-14.0	0.0859	-3.2
1995	9.02%	-4.6	9.78%	5.54%	7.76%	-5.1	0.945	0.8%	6.9%	44.7	5.8%	1.8	3.7%	0.0999	29.0	0.0890	3.6
1996	8.11%	-10.6	10.35%	6.20%	7.42%	-4.5	0.976	3.2%	4.2%	-49.1	5.2%	-10.3	3.7%	0.0762	-27.1	0.0853	-4.3
1997	6.95%	-15.4	10.94%	5.45%	6.41%	-14.7	1.000	2.5%	3.9%	-8.1	5.0%	-3.4	3.7%	0.0752	-1.3	0.0861	0.9
1998	6.22%	-11.1	8.77%	5.03%	5.79%	-10.1	1.033	3.3%	2.4%	-46.7	3.5%	-35.2	3.7%	0.0628	-18.0	0.0736	-15.6
1999	6.64%	6.5	9.93%	8.88%	7.45%	25.1	1.050	1.6%	5.9%	87.2	4.1%	14.3	3.7%	0.0995	46.0	0.0810	9.6
2000	7.13%	7.1	10.94%	7.32%	7.20%	-3.4	1.072	2.1%	5.1%	-13.6	4.5%	9.4	3.7%	0.0934	-6.3	0.0867	6.8
2001	7.09%	-0.5	7.44%	10.21%	8.22%	13.2	1.074	0.2%	8.0%	45.0	6.3%	34.7	3.7%	0.1258	29.7	0.1077	21.6
2002	6.98%	-1.6	5.70%	6.42%	6.78%	-19.2	1.088	1.3%	5.5%	-37.6	6.2%	-1.9	3.7%	0.0994	-23.5	0.1070	-0.6
2003	6.50%	-7.1	9.64%	7.40%	6.83%	0.7	1.089	0.1%	6.7%	19.6	6.7%	8.1	3.7%	0.1132	13.0	0.1137	6.0
2004	6.06%	-7.0	11.39%	7.91%	6.73%	-1.4	1.131	3.9%	2.9%	-84.9	5.0%	-29.4	3.7%	0.0731	-43.7	0.0966	-16.2
2005	5.36%	-12.3	12.59%	7.62%	6.18%	-8.6	1.167	3.2%	3.0%	5.5	4.2%	-18.0	3.7%	0.0775	5.8	0.0907	-6.3
2006	5.40%	0.6	12.52%	7.43%	6.13%	-0.8	1.182	1.3%	4.8%	46.9	3.6%	-16.0	3.7%	0.1002	25.7	0.0855	-5.9
Average Annual Growth Rate (%)																	
1997-2006		**-2.82**	**1.50**	**3.45**		**-0.50**		**1.86**		**2.37**		**-3.77**	**0.00**		**3.20**		**-0.07**
1998-2006		**-1.78**	**4.45**	**4.88**		**0.70**		**1.68**		**8.50**		**0.16**	**0.00**		**5.84**		**1.88**

[0] Assumes replacement valuation of assets and a constant rate of depreciation.

[1] Source: Statistics Canada, average yields on Canadian long-term corporate bonds.

[2] All growth rates are calculated logarithmically save for that of the construction cost index.

[3] Source: Statistics Canada, CANSIM Tables. Quarterly Statement of Changes in Financial Position, by North American Industry Classification System (NAICS), selected financial ratios.

[4] Calculation of weighted average cost of capital is 65% corporate long term bond, 35% ROE for utilities. Weights reflect Ontario gas utility norms

[5] This index was calculated as a ratio of the current cost of gross plant to the cost of gross plant at 1997 levels. This data was obtained from Statistics Canada's Table on Flows and Stocks of Fixed Non-Residential Capital

[6] Assumes depreciation based on the 46 year service life for Union Gas.

FIGURE 2: CALCULATION OF UNSMOOTHED GEOMETRIC DECAY CAPITAL SERVICE PRICE INDEX

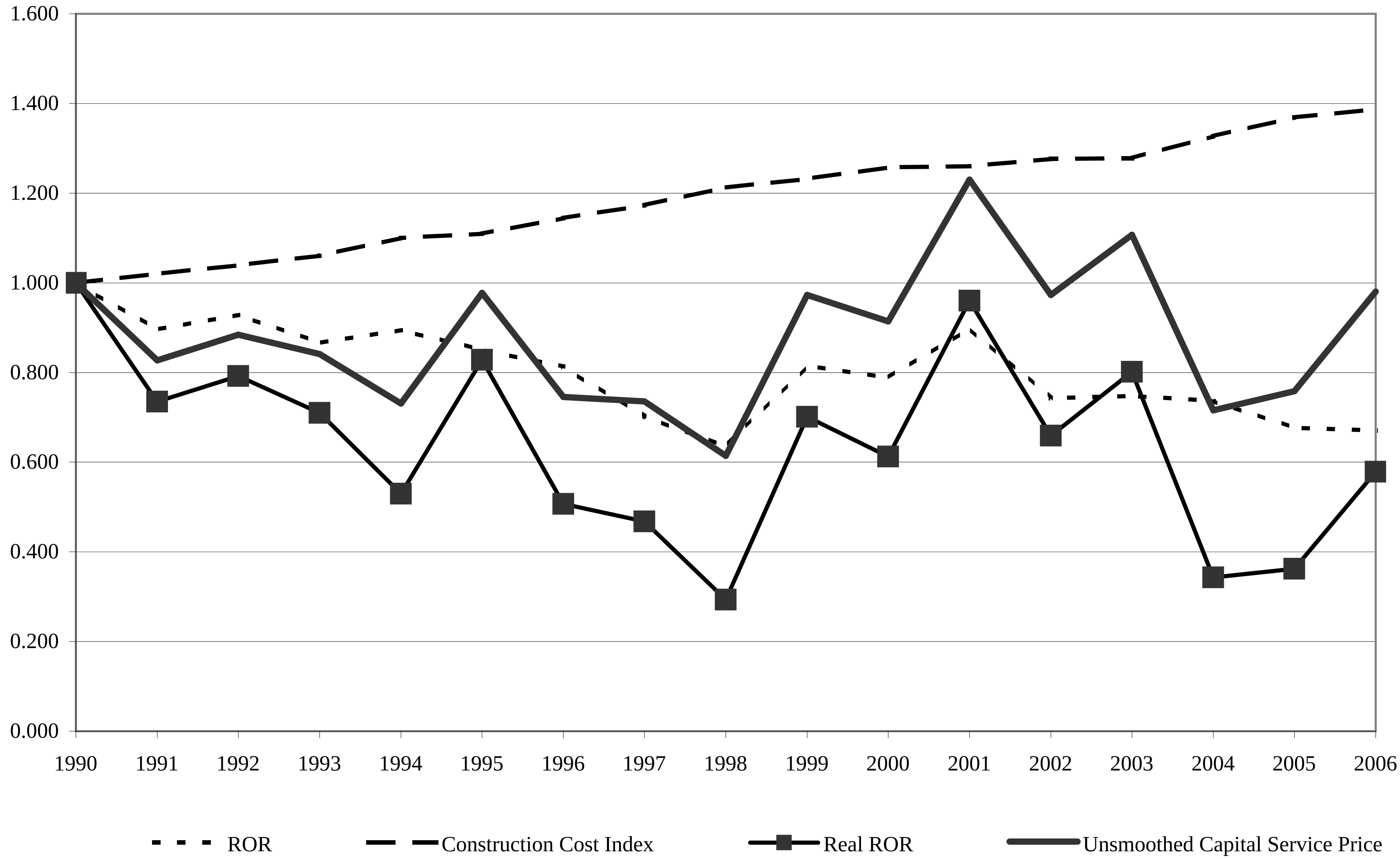
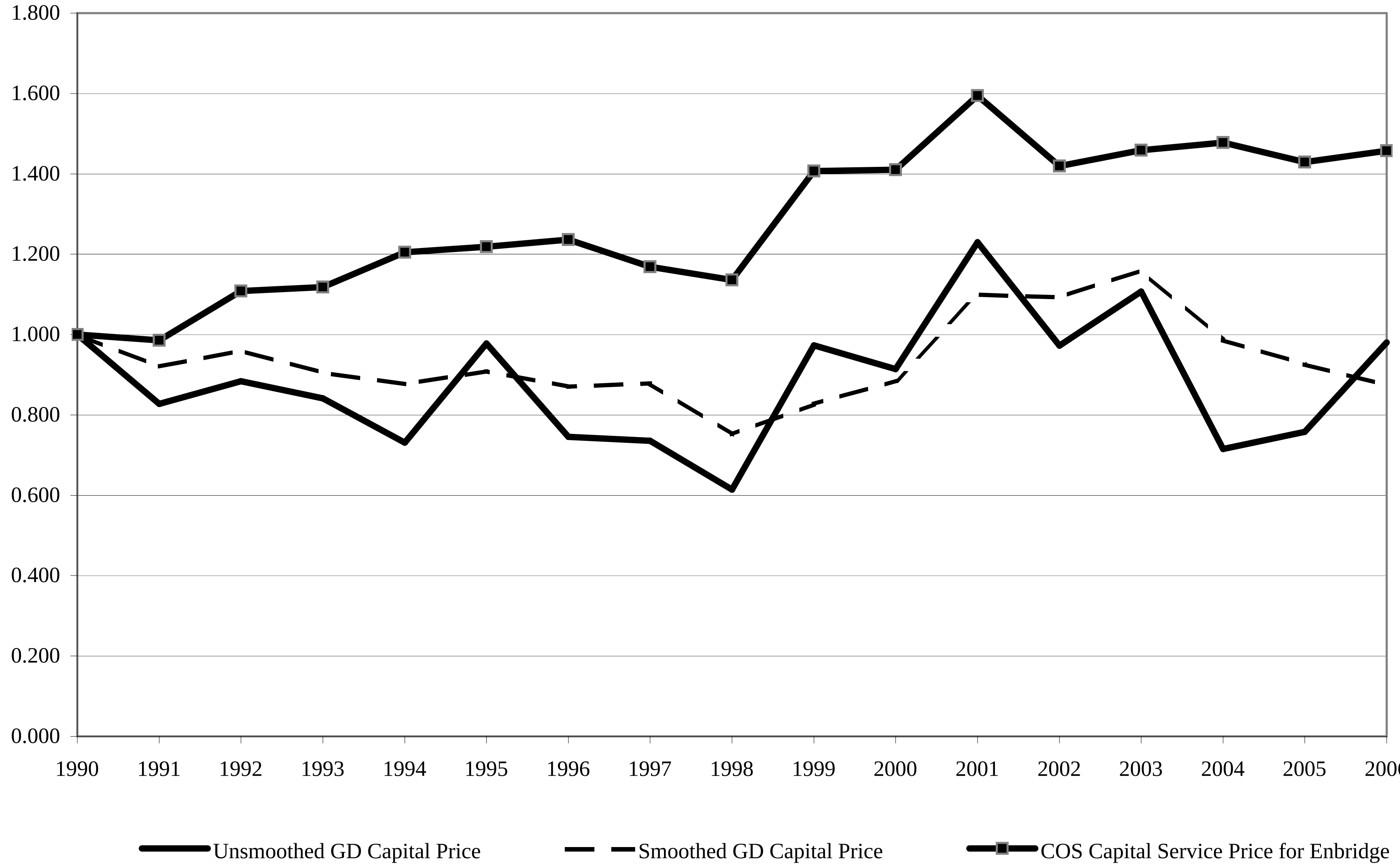


FIGURE 3: COMPARISONS OF ALTERNATIVE CAPITAL SERVICE PRICE INDEXES



3% annually in 2004 and 2005. The weighted average ROR, meanwhile, was little changed in 2004 and then fell by almost 9% in 2005. The end result was that the (unsmoothed) real rate of return fell sharply in 2004 to a level reached on only one occasion in the last fifteen years. The real rate of return then rose sharply in 2006. Figure 2 shows that fluctuations in the real rate of return are the chief cause of fluctuations in the capital service price. Figure 3 shows that conventional smoothing of the capital service price by no means eliminates all volatility.

Tables 13a and 13b report the calculation of the input price indexes for Enbridge and Union using GD capital costing. The indexes for the two companies have common price subindexes but different weights.[45] Inspecting the results of the two tables it can be seen that the sharp decline in the capital service prices had a major effect on the summary input prices for both companies, and were the source of considerable volatility. For example, the smoothed input price index for Enbridge fell by about 10% in 2004. The sensitivity of the summary input price indexes to the fluctuations in the capital service components reflects in part the large weighting assigned to capital in index construction.

In an effort to control for this volatility when using GD capital costing, we sought a period ending in 2006 in which the start year had a similar smoothed real rate of return on the premise that a notable change in the real rate of return is not likely during the IR plan. The 1998-2006 period was chosen using these criteria. The 1999-2005 period was previously chosen using the same criteria.[46]

Table 14 reports the input price differentials for Enbridge and Union using GD capital costing. This exercise requires an estimate of the input price trend of the Canadian economy. Such indexes are not expressly computed by the federal government. We used index logic to calculate the economy's input price trend using other government indexes. To the extent that the economy earns a competitive return in the longer run, the trend in its *input* prices is the sum of the trends in its *output* prices and its TFP. Using GDPIPI as an output price index and the multifactor productivity ("MFP") index for the Canadian private

[45] The input price index for gas was removed from the calculation in the latest study.

[46] The consideration of years prior to 2000 is made possible by the fact that the input price subindexes for those years are readily available. The input price trends can then by estimated by assuming that the cost shares for earlier years were the same as those in the earliest years for which the data on the costs of the Ontario utilities are available.

Table 13a

Input Price Index: Geometric Decay Capital Cost for Enbridge Gas Distribution

Year	Capital (Real Rate Smoothed)			Labour			Materials and Services			Summary Index	
	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Level	Growth Rate (%)
1990	0.0980		67.1	90.3	5.93	10.5	89.2	3.19	22.4	1.00	
1991	0.0901	-8.37	67.1	96.5	6.64	10.5	93.0	4.17	22.4	0.96	-3.98
1992	0.0940	4.29	67.1	100	3.56	10.5	93.2	0.21	22.4	0.99	3.30
1993	0.0887	-5.88	67.1	102.6	2.57	10.5	94.6	1.49	22.4	0.96	-3.34
1994	0.0859	-3.22	67.1	105.7	2.98	10.5	94.7	0.11	22.4	0.94	-1.82
1995	0.0890	3.62	67.1	108.3	2.43	10.5	96.8	2.19	22.4	0.97	3.18
1996	0.0853	-4.31	67.1	109.5	1.10	10.5	98.4	1.64	22.4	0.95	-2.41
1997	0.0861	0.92	67.1	111.5	1.81	10.5	100.0	1.61	22.4	0.96	1.17
1998	0.0736	-15.60	67.1	113.6	1.87	10.5	100.3	0.30	22.4	0.87	-10.20
1999	0.0810	9.56	67.1	115.4	1.57	10.5	101.0	0.70	22.4	0.93	6.73
2000	0.0867	6.81	67.1	117.9	2.14	10.5	102.7	1.67	22.4	0.98	5.17
2001	0.1077	21.64	68.9	120.8	2.43	9.3	103.9	1.16	21.8	1.14	15.21
2002	0.1070	-0.58	70.1	124.6	3.10	8.3	106.1	2.10	21.7	1.14	0.33
2003	0.1137	6.01	68.0	127.8	2.54	7.5	108.1	1.87	24.6	1.20	4.78
2004	0.0966	-16.25	64.1	131.5	2.85	7.8	110.0	1.74	28.1	1.08	-10.05
2005	0.0907	-6.31	61.9	135.6	3.07	8.7	111.1	1.00	29.4	1.05	-3.43
2006	0.0855	-5.87	59.3	139.1	2.55	8.9	112.8	1.52	31.8	1.02	-2.87
Average Annual Growth Rate (%) 1998-2006		**1.88**			**2.53**			**1.47**			**1.98**

[0] Source: PEG calculation. See Table 12 for details.

[1] Source: Cost shares based on PEG research on Enbridge Gas Distribution.

[2] Source: Statistics Canada, Construction Union Wage Rate Index for Ontario with Selected Pay Supplements.

[3] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Table 13b

Input Price Index: Geometric Decay Capital Cost for Union Gas

Year	Capital (Real Rate Smoothed) Index[0]	Capital Growth Rate (%)	Capital Weight[1] (%)	Labour Index[2]	Labour Growth Rate (%)	Labour Weight[1] (%)	Materials and Services Index[3]	Materials and Services Growth Rate (%)	Materials and Services Weight[1] (%)	Summary Index Level	Summary Index Growth Rate (%)
1990	0.0980		63.4	90.3	5.93	21.3	89.2	3.19	15.3	1.00	
1991	0.0901	-8.37	63.4	96.5	6.64	21.3	93.0	4.17	15.3	0.97	-3.25
1992	0.0940	4.29	63.4	100	3.56	21.3	93.2	0.21	15.3	1.00	3.51
1993	0.0887	-5.88	63.4	102.6	2.57	21.3	94.6	1.49	15.3	0.97	-2.95
1994	0.0859	-3.22	63.4	105.7	2.98	21.3	94.7	0.11	15.3	0.96	-1.39
1995	0.0890	3.62	63.4	108.3	2.43	21.3	96.8	2.19	15.3	0.99	3.15
1996	0.0853	-4.31	63.4	109.5	1.10	21.3	98.4	1.64	15.3	0.97	-2.25
1997	0.0861	0.92	63.4	111.5	1.81	21.3	100.0	1.61	15.3	0.98	1.22
1998	0.0736	-15.60	63.4	113.6	1.87	21.3	100.3	0.30	15.3	0.89	-9.45
1999	0.0810	9.56	63.4	115.4	1.57	21.3	101.0	0.70	15.3	0.95	6.50
2000	0.0867	6.81	64.7	117.9	2.14	20.8	102.7	1.67	14.5	1.00	5.06
2001	0.1077	21.64	67.6	120.8	2.43	18.7	103.9	1.16	13.7	1.16	14.95
2002	0.1070	-0.58	65.8	124.6	3.10	18.5	106.1	2.10	15.7	1.17	0.50
2003	0.1137	6.01	67.3	127.8	2.54	18.3	108.1	1.87	14.4	1.23	4.75
2004	0.0966	-16.25	63.1	131.5	2.85	20.5	110.0	1.74	16.4	1.11	-9.77
2005	0.0907	-6.31	61.2	135.6	3.07	22.8	111.1	1.00	16.0	1.08	-3.09
2006	0.0855	-5.87	58.7	139.1	2.55	24.6	112.8	1.52	16.7	1.05	-2.67
Average Annual Growth Rate (%) 1998-2006		**1.88**			**2.53**			**1.47**			**2.03**

[0] Source: PEG calculation. See Table 12 for details.

[1] Source: Cost shares based on PEG research on Union Gas.

[2] Source: Statistics Canada, Construction Union Wage Rate Index for Ontario with Selected Pay Supplements.

[3] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Table 14

Input Price Differentials: Geometric Decay Capital Cost

	Input Price Indexes										Input Price Differentials	
	Canadian Economy					Enbridge[3]		Union[4]			(Economy - Enbridge)	(Economy - Union)
	GDP-IPI[1]		MFP[2]		Estimated	Index	Growth	Index	Growth		Growth	Growth
	Level	Growth Rate [A] (%)	Level	Growth Rate [B] (%)	Growth Rate [C]=A+B (%)		Rate [D] (%)		Rate [E] (%)		Rate [C]-[D] (%)	Rate [C]-[E] (%)
1988	81.6		96.3									
1989	85.2	4.32	95.2	-1.15	3.17							
1990	88.4	3.69	93.4	-1.91	1.78	1.00		1.00				
1991	91.4	3.34	90.9	-2.71	0.62	0.96	-3.98	0.97	-3.25		4.60	3.88
1992	93.0	1.74	91.3	0.44	2.17	0.99	3.30	1.00	3.51		-1.12	-1.33
1993	94.9	2.02	92.2	0.98	3.00	0.96	-3.34	0.97	-2.95		6.34	5.95
1994	96.3	1.46	94.5	2.46	3.93	0.94	-1.82	0.96	-1.39		5.75	5.32
1995	97.4	1.14	94.6	0.11	1.24	0.97	3.18	0.99	3.15		-1.93	-1.91
1996	98.5	1.12	93.7	-0.96	0.17	0.95	-2.41	0.97	-2.25		2.58	2.42
1997	100.0	1.51	94.9	1.27	2.78	0.96	1.17	0.98	1.22		1.61	1.57
1998	101.3	1.29	95.6	0.73	2.03	0.87	-10.20	0.89	-9.45		12.23	11.48
1999	102.6	1.28	97.5	1.97	3.24	0.93	6.73	0.95	6.50		-3.49	-3.26
2000	105.0	2.31	99.7	2.23	4.54	0.98	5.17	1.00	5.06		-0.62	-0.52
2001	106.8	1.70	99.3	-0.40	1.30	1.14	15.21	1.16	14.95		-13.91	-13.65
2002	109.3	2.31	100	0.70	3.02	1.14	0.33	1.17	0.50		2.69	2.52
2003	110.8	1.36	99.5	-0.50	0.86	1.20	4.78	1.23	4.75		-3.92	-3.89
2004	112.5	1.52	99.1	-0.40	1.12	1.08	-10.05	1.11	-9.77		11.17	10.89
2005	114.7	1.94	99.3	0.20	2.14	1.05	-3.43	1.08	-3.09		5.57	5.23
2006	116.8	1.81	99.1	-0.20	1.61	1.02	-2.87	1.05	-2.67		4.48	4.28
Average Annual Growth Rate (%) 1998-2006		**1.78**		**0.45**	**2.23**		**1.98**		**2.03**		**0.25**	**0.20**

[1]Source: Statistics Canada, GDP-IPI, Final Domestic Demand for Canada.

[2]Source: Statistics Canada, Multifactor productivity of aggregate business sector.

[3] See Tables 12 and 13a for details of calculations and the index level for Enbridge.

[4] See Tables 12 and 13b for details of calculations and the index level for Union.

business sector as a measure of the economy's TFP growth we can then estimate the trend in the economy's input prices.

Results for the 1998-2006 and 1998-2005 periods are calculated and highlighted in Table 14 for reader convenience. We found that the appropriate input price differentials for Enbridge and Union using GD capital costing were 0.25% and 0.20% respectively. In other words, after controlling for volatility in the real rate of return, we find that the input price trend of the economy grew a little more rapidly than the input price trend of the industry. Remarkably similar results were obtained for the 1998-2005 period.

As for the COS capital service price indexes, we found that there was no start date in which the ROR was very similar to that in 2006. However, an average of the ROR values for 1997 and 1998 was quite similar to the 2006 value since the 1997 value was a little too high while the 1998 value was a little too low to be a good match. We, accordingly, chose to set the IPDs by taking an average of the 1997-2006 and 1998-2006 comparisons. This approach is based on the premise that the weighted average cost of funds won't change over the IRM period.

Input price trends using the COS approach to capital costing are reported in Tables 15a and 15b. These employ the same price subindexes for labour and M&S that are used with the GD costing. The capital service prices reflect the COS treatment and differ between the two companies due to differences in their historical investment patterns. For example, we would expect the capital price for Enbridge to rise more rapidly than Union's due to the former company's brisk customer growth. These indexes are much more stable than their GD counterparts and required no smoothing.

Input price differentials using COS costing are reported in Table 16. Results for the 1997-2006 and 1998-2006 periods are calculated and highlighted for reader convenience. We found that the appropriate input price differentials for Enbridge and Union using COS costing are -0.22% and -0.14 respectively. Using the COS approach to capital costing, it follows that the input price trend of the industry is a little *more* rapid than that of the economy.

The greater stability of the COS input price index, well depicted in Figure 3, is evidently a major advantage in the calculation of IPDs. The COS method thus provides a solid basis for IPD calculations in addition to providing a useful point of comparison for

Table 15a

Input Price Index with COS Capital Cost: Enbridge Gas Distribution

	Capital (COSR Method)			Labour			Materials and Services			Summary Index	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Index	Growth Rate (%)
1990	0.0566		65.7	90.3		11.0	89.2		23.3	1.000	
1991	0.0558	-1.4	65.7	96.5	6.6	11.0	93.0	4.2	23.3	1.008	0.8
1992	0.0627	11.7	65.7	100	3.6	11.0	93.2	0.2	23.3	1.093	8.1
1993	0.0633	0.8	65.7	102.6	2.6	11.0	94.6	1.5	23.3	1.106	1.2
1994	0.0682	7.5	65.7	105.7	3.0	11.0	94.7	0.1	23.3	1.166	5.3
1995	0.0690	1.1	65.7	108.3	2.4	11.0	96.8	2.2	23.3	1.184	1.5
1996	0.0700	1.5	65.7	109.5	1.1	11.0	98.4	1.6	23.3	1.201	1.5
1997	0.0661	-5.6	65.7	111.5	1.8	11.0	100.0	1.6	23.3	1.164	-3.1
1998	0.0643	-2.9	65.7	113.6	1.9	11.0	100.3	0.3	23.3	1.146	-1.6
1999	0.0796	21.4	65.7	115.4	1.6	11.0	101.0	0.7	23.3	1.323	14.4
2000	0.0798	0.2	65.7	117.9	2.1	11.0	102.7	1.7	23.3	1.334	0.8
2001	0.0902	12.3	64.6	120.8	2.4	10.6	103.9	1.2	24.8	1.453	8.5
2002	0.0803	-11.6	65.6	124.6	3.1	9.5	106.1	2.1	24.9	1.358	-6.7
2003	0.0825	2.7	61.9	127.8	2.5	8.9	108.1	1.9	29.2	1.392	2.5
2004	0.0836	1.3	60.9	131.5	2.9	8.4	110.0	1.7	30.6	1.414	1.6
2005	0.0809	-3.3	60.3	135.6	3.1	9.1	111.1	1.0	30.6	1.394	-1.5
2006	0.0825	1.9	60.1	139.1	2.5	8.7	112.8	1.5	31.2	1.420	1.9
Average Annual Growth Rates (%)											
1997-2006		**2.45**			**2.46**			**1.34**			**2.20**
1998-2006		**3.12**			**2.53**			**1.47**			**2.68**

[0] PEG calculation using Enbridge plant data.

[1] Weights based on research for Enbridge Gas Distribution.

[2] Source: Statistics Canada, Construction Union Wage Rate Index with Selected Pay Supplements.

[3] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Table 15b

Input Price Index with COS Capital Cost: Union Gas

	Capital (COSR Method)			Labour			Materials and Services			Summary Index	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Index	Growth Rate (%)
1990	0.0601		55.0	90.3		32.2	89.2		12.8	1.000	
1991	0.0598	-0.5	55.0	96.5	6.6	32.2	93.0	4.2	12.8	1.024	2.38
1992	0.0653	8.9	55.0	100	3.6	32.2	93.2	0.2	12.8	1.088	6.05
1993	0.0654	0.2	55.0	102.6	2.6	32.2	94.6	1.5	12.8	1.100	1.11
1994	0.0702	7.1	55.0	105.7	3.0	32.2	94.7	0.1	12.8	1.155	4.88
1995	0.0717	2.0	55.0	108.3	2.4	32.2	96.8	2.2	12.8	1.180	2.16
1996	0.0719	0.3	55.0	109.5	1.1	32.2	98.4	1.6	12.8	1.189	0.74
1997	0.0669	-7.2	55.0	111.5	1.8	32.2	100.0	1.6	12.8	1.152	-3.16
1998	0.0644	-3.8	55.0	113.6	1.9	29.9	100.3	0.3	15.1	1.135	-1.49
1999	0.0790	20.4	59.8	115.4	1.6	23.4	101.0	0.7	16.9	1.283	12.25
2000	0.0791	0.2	61.9	117.9	2.1	22.5	102.7	1.7	15.6	1.294	0.87
2001	0.0894	12.2	62.1	120.8	2.4	21.8	103.9	1.2	16.0	1.406	8.27
2002	0.0797	-11.4	60.2	124.6	3.1	21.5	106.1	2.1	18.3	1.325	-5.97
2003	0.0817	2.5	60.3	127.8	2.5	22.2	108.1	1.9	17.4	1.357	2.40
2004	0.0827	1.1	58.4	131.5	2.9	23.1	110.0	1.7	18.5	1.379	1.63
2005	0.0798	-3.5	57.6	135.6	3.1	24.9	111.1	1.0	17.5	1.364	-1.11
2006	0.0818	2.4	57.7	139.1	2.5	25.2	112.8	1.5	17.2	1.396	2.31
Average Annual Growth Rates (%)											
1997-2006		**2.23**			**2.46**			**1.34**			**2.13**
1998-2006		**2.99**			**2.53**			**1.47**			**2.58**

[0] PEG calculation using Union plant data.

[1] Weights based on research for Union Gas.

[2] Source: Statistics Canada, Construction Union Wage Rate Index with Selected Pay Supplements.

[3] Source: Statistics Canada, Ontario GDP-IPI at Market Prices.

Table 16

Input Price Differentials with COS Capital Cost

	Canadian Economy						Ontario Gas Industry				Input Price Differential	
	GDP-IPI[1]		MFP[2]		Implied IPI		Enbridge[3]		Union[4]			
	Level	Growth Rate [A] (%)	Level	Growth Rate [B] (%)	Index	Growth Rate [C]=A+B (%)	Index	Growth Rate [D] (%)	Index	Growth Rate [E] (%)	Enbridge [C]-[D] (%)	Union [C]-[E] (%)
1990	88.4		93.4		1.00		1.00		1.00			
1991	91.4	3.3	90.9	-2.7	1.01	0.6	1.01	0.8	1.02	2.4	-0.1	-1.8
1992	93.0	1.7	91.3	0.4	1.03	2.2	1.09	8.1	1.09	6.1	-6.0	-3.9
1993	94.9	2.0	92.2	1.0	1.06	3.0	1.11	1.2	1.10	1.1	1.8	1.9
1994	96.3	1.5	94.5	2.5	1.10	3.9	1.17	5.3	1.16	4.9	-1.4	-1.0
1995	97.4	1.1	94.6	0.1	1.12	1.2	1.18	1.5	1.18	2.2	-0.3	-0.9
1996	98.5	1.1	93.7	-1.0	1.12	0.2	1.20	1.5	1.19	0.7	-1.3	-0.6
1997	100.0	1.5	94.9	1.3	1.15	2.8	1.16	-3.1	1.15	-3.2	5.9	5.9
1998	101.3	1.3	95.6	0.7	1.17	2.0	1.15	-1.6	1.14	-1.5	3.6	3.5
1999	102.6	1.3	97.5	2.0	1.21	3.2	1.32	14.4	1.28	12.3	-11.1	-9.0
2000	105.0	2.3	99.7	2.2	1.27	4.5	1.33	0.8	1.29	0.9	3.8	3.7
2001	106.8	1.7	99.3	-0.4	1.28	1.3	1.45	8.5	1.41	8.3	-7.3	-7.0
2002	109.3	2.3	100	0.7	1.32	3.0	1.36	-6.7	1.32	-6.0	9.8	9.0
2003	110.8	1.4	99.5	-0.5	1.34	0.9	1.39	2.5	1.36	2.4	-1.6	-1.5
2004	112.5	1.5	99.1	-0.4	1.35	1.1	1.41	1.6	1.38	1.6	-0.5	-0.5
2005	114.7	1.9	99.3	0.2	1.38	2.1	1.39	-1.5	1.36	-1.1	3.6	3.3
2006	116.8	1.8	99.1	-0.2	1.40	1.6	1.42	1.9	1.40	2.3	-0.2	-0.7
Average Annual Growth Rates (%)												
1997-2006		**1.73**		**0.48**		**2.21**		**2.20**		**2.13**	**0.00**	**0.08**
1998-2006		**1.78**		**0.45**		**2.23**		**2.68**		**2.58**	**-0.45**	**-0.35**
Average				**0.47**		**2.22**		**2.44**		**2.36**	**-0.22**	**-0.14**

¹ Source: Statistics Canada, GDP-IPI, Final Domestic Demand, for Canada.
² Source: Statistics Canada, Multifactor productivity of aggregate business sector.
³ Source: See Table 15a for details of calculations.
⁴ Source: See Table 15b for details of calculations.

IPDs calculated using GD costing. The GD approach is more familiar to Ontario stakeholders and better established.

3.6 Stretch Factor

The stretch factor term of the X factor was noted in Section 2 to facilitate the sharing between utilities and customers of any benefits that are expected to result from the stronger performance incentives that are generated by the plan. We have relied on two sources in developing our stretch factor recommendation. One is historical precedent. In research for Board Staff last year to develop an IR plan for power distributors we found that the average explicit stretch factor approved for the rate escalation indexes of North American energy utilities is around 0.50%.

A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that sampled utilities operated to that predicted under an approximation of the envisioned IR under alternative stylized regulatory systems.[47] By comparing the performance predicted under an approximation to the regulatory system under which plan, we can estimate the expected performance improvement resulting from the change in regulation. The last step in the analysis is to share the expected improvement between the company and its customers.

The proposed productivity targets for Enbridge reflect exclusively the TFP trends of US gas utilities from 1994 to 2004. Based on our experience, we believe that these utilities held rate cases about every three years on average during the sample period used to estimate their TFP trends. We are interested in the performance improvement in moving from a three year regulatory lag to the six years envisioned by staff. Our incentive power research suggests that annual performance growth should accelerate by 0.84% on average. Half of this is 0.42%. This research substantiates the appropriateness of a stretch factor around 0.5% and we propose this for both companies.

3.7 Summary PCI Results

For reader convenience, we gather in the table below the results of our research to calculate X factors for the summary PCIs of Enbridge and Union. The table provides, in

[47] Details of our incentive power research were discussed in our response to Enbridge data request 45.

italics, a notion of the growth that these PCIs would have achieved during the IR plan. This projection requires an assumption regarding GDPIPI growth, and we use for this purpose the recent historical trend. The growth in the *actual* PCI would reflect the growth in the actual GDPIPI for final domestic demand during the IR plan period.

Price Cap Index Details

	GD Capital Cost		COS Capital Cost	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.80	1.32	1.95	1.84
$TFP^{Economy}$ [B]	0.45	0.45	0.47	0.47
PD [C=A-B]	**1.35**	**0.87**	**1.48**	**1.37**
Input $Prices^{Economy}$ [D]	2.23	2.23	2.22	2.22
Input $Prices^{Industry}$ [E]	1.98	2.03	2.44	2.36
IPD [F=D-E]	**0.25**	**0.20**	**-0.22**	**-0.14**
$Output^{Revenue\text{-}Weighted}$ [G]	1.68	1.05	1.68	1.05
$Output^{Elasticity\text{-}Weighted}$ [H]	2.84	1.63	2.96	1.77
AU [I=G-H]	**-1.16**	**-0.58**	**-1.28**	**-0.72**
Stretch [J]	**0.50**	**0.50**	**0.50**	**0.50**
X [K=C+F+I+J]	**0.94**	**0.99**	**0.48**	**1.01**
GDPIPI FDD [L]	*1.78*	*1.78*	*1.78*	*1.78*
Notional PCI growth [L-K]	*0.84*	*0.79*	*1.30*	*0.77*

It can be seen that, for both companies, the growth of the PCIs based on the recommended COS approach to capital costing would be materially slower than the growth in the GDPIPI. Ontario gas consumers would, in other words, experience growth in rates for gas utility services that are below the general inflation in the prices of final goods and services in Canada.

3.8 Price Caps for Service Groups

We propose that any PCI designed for a specific service group have a GDPIPI-X growth rate formula in which the X factor is the sum of the X factor for the *summary* PCI and a special adjustment factor ("ADJ") that is specific to the service group and effectively customizes the X factor for the group. We developed service specific PCIs for Union's new M1 and M2 rate classes, rates 01 and 10, and for Enbridge Rate 1. All other services for each company would be subject to a common PCI.

Original theoretical and empirical research was undertaken to provide a rigorous foundation for the design of ADJ factors. The basic intuition is that the PCI for a specific service group should reflect the manner in which its impact on TFP growth differs from the impact of *all* services that is reflected in the X of the summary PCI. The impact of a service group on TFP growth depends on the pace and pattern of its output growth. Output growth has an impact on cost as well as revenue. The growth of residential output, for instance, can have a special effect on revenue when there is declining average use but can also have a special effect on cost to the extent that customer growth is especially costly to accommodate. The cost impact of growth in industrial output can be quite different. Our ADJ formula involves separate consideration of these cost and revenue effects. Details of the theory are set forth in Section A.7.4 of the Appendix.

Regarding empirical implementation, we gauge the differential impact of the services on revenue growth (the "revenue effect") using the difference between revenue-weighted output indexes for the particular service group and for all services. A negative difference (*i.e.* a negative revenue effect) would lower the ADJ and the resultant X factor. We gauge the differential impact of output growth on cost using formulas that involve output growth trends and elasticity estimates. This is a matter of taking the difference between the cost impact of growth in all of the company's services and the cost impact of growth in the output of individual service groups. A negative difference (*i.e.* a negative cost effect) would indicate that growth in the output of the service group would raise the cost of a stand-alone service more than growth in the output of all services would do for companies like Enbridge and Union. Such a finding would lower the ADJ and the resultant X factor for the group.

In table 17 we provide calculations of the ADJ factors for several service groups and a notion of the growth trend of the resultant PCIs. The cost effects are separately calculated using both GD and COS costing. Using both approaches to capital costing it can be seen that all three service classes that include service to residential customers have negative ADJs, as we would expect. These will lower the X factors and cause the PCIs for these services to grow more rapidly than the summary PCI. Customers of these services will thus

Table 17

Calculation of the ADJ Factors

	Share Volume Residential (2002)	Revenue Effect [A]	**Geometric Decay Capital Costing** Cost Effect [B]	ADJ [A+B]	**COS Capital Costing** Cost Effect [C]	ADJ [A+C]
Enbridge						
Rate 1 (Residential)	100%	0.66%	-1.20%	-0.55%	-1.23%	-0.57%
All Non-Residential Services	0%	-1.18%	2.29%	1.11%	2.35%	1.17%
Union						
Rate M1 (General Services South)	77%	0.66%	-1.46%	-0.80%	-1.44%	-0.78%
Rate 01 (General Services North)	75%	-0.85%	0.31%	-0.54%	0.28%	-0.57%
Rate M2 (General Services South)	0%	-1.98%	1.55%	-0.43%	1.52%	-0.46%
Rate 10 (General Services North)	0%	-0.14%	1.14%	1.00%	1.22%	1.08%
Other Services	0%	-0.62%	1.50%	0.88%	1.50%	0.88%

play a disproportionately large role in compensating utilities for the special financial challenges that service to the groups poses. The indicated ADJs for all other services of Enbridge and Union are positive. This will raise their X factors and slow the pace of PCI growth. Customers of these services will thus enjoy rate escalation that is considerably slower than the escalation of rates of services involving residential customers.

We provide preliminary estimates of the pace of escalation in the group-specific PCIs that might result from our calculations using COS capital costing by taking the difference between the trends in the GDPIPI from 2000 to 2006 and the X factor for each group. The actual growth in the PCIs would, once again, depend on the GDPIPI growth that occurs during the IR plan period. Results of this crude forecasting method are presented in the following table.

Service Group PCIs

COS Capital Cost

Company	Service Group	Sum of Common Terms [A]	ADJ [B]	**Total X Factor [C]=A+B**	*Recent GDPIPI Trend [D]*	***Notional PCI Growth [D]-[C]***
Enbridge	Rate 1	0.48	-0.57	**-0.09**	*1.78*	***1.87***
	Nonresidential	0.48	1.17	**1.65**	*1.78*	***0.13***
Union	Rate M1	1.01	-0.78	**0.23**	*1.78*	***1.55***
	Rate M2	1.01	-0.46	**0.55**	*1.78*	***1.23***
	Rate 01	1.01	-0.57	**0.44**	*1.78*	***1.34***
	Rate 10	1.01	1.08	**2.09**	*1.78*	***-0.31***
	Other Services	1.01	0.88	**1.89**	*1.78*	***-0.11***

Service Group PCIs

GD Capital Cost

Company	Service Group	Sum of Common Terms [A]	ADJ [B]	**Total X Factor [C]=A+B**	*Recent GDPIPI Trend [D]*	***Notional PCI Growth [D]-[C]***
Enbridge	Rate 1	0.94	-0.55	**0.39**	*1.78*	***1.39***
	Nonresidential	0.94	1.11	**2.05**	*1.78*	***-0.27***
Union	Rate M1	0.99	-0.80	**0.19**	*1.78*	***1.59***
	Rate M2	0.99	-0.43	**0.56**	*1.78*	***1.22***
	Rate 01	0.99	-0.54	**0.45**	*1.78*	***1.33***
	Rate 10	0.99	1.00	**1.99**	*1.78*	***-0.21***
	Other Services	0.99	0.88	**1.87**	*1.78*	***-0.09***

We believe that our methodology for ADJ calculation can produce sensible adjustments for individual service groups during the IR period. However, the method has the disadvantage of being complex and novel. Stakeholders who are uncomfortable with the approach can nonetheless use it to appraise the merits of alternative and simpler methods for establishing service group PCIs.

3.9 Revenue per Customer Caps

The general formula for calculating the X factor of a revenue per customer cap was detailed in Section 2.2.4. This formula includes the inflation measure, PD, IPD, and stretch found in PCI formulas. There is no average use factor --- the difference between the growth in revenue-weighted and elasticity-weighted output --- since this is designed to correct for any inaccuracy of the elasticity-weighted output index used to calculate PD when the goal is to limit the growth in *prices.*[48] The revenue per customer cap instead features an RC factor--- the difference between growth in customers and the growth of elasticity-weighted output.

[48] The price index that the PCI is designed to regulate is the ratio of revenue to the revenue-weighted output index.

This is designed to correct for any inaccuracy in the use of the output index to calculate PD when the goal is to limit growth in revenue *per customer*.

Our research permits an implementation of this formula. Illustrative results appear in the table below. To help stakeholders gauge the likely outcome of an RCI, we also provide, in italics, a notion of how one might rise if the output and GDPIPI terms of the formula grow at their average annual growth rates over the 2000-2006 period.

Revenue Per Customer Cap Details

	GD Capital Cost		**COS Capital Cost**	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.80	1.32	1.95	1.84
$TFP^{Economy}$ [B]	0.45	0.45	0.47	0.47
PD [C=A-B]	**1.35**	**0.87**	**1.48**	**1.37**
Input $Prices^{Economy}$ [D]	2.23	2.23	2.22	2.22
Input $Prices^{Industry}$ [E]	1.98	2.03	2.44	2.36
IPD [F=D-E]	**0.25**	**0.20**	**-0.22**	**-0.14**
Customers [G]	3.28	2.02	3.28	2.02
$Output^{Elasticity\text{-}Weighted}$[H]	2.84	1.63	2.96	1.77
RC [I=G-H]	**0.44**	**0.39**	**0.32**	**0.25**
Stretch [J]	**0.50**	**0.50**	**0.50**	**0.50**
X [K=C+F+I+J]	**2.54**	**1.96**	**2.08**	**1.98**
GDPIPI FDD [L]	*1.78*	*1.78*	*1.78*	*1.78*
Notional RC growth [L-K]	*-0.76*	*-0.18*	*-0.30*	*-0.20*

3.10 Capex Budgets and The Y Factoring of Capex

Enbridge Gas Distribution has maintained in this proceeding that it may wish to Y factor certain categories of capital spending as a component of its IRM. In response to data requests, it reported that in 2006 the eligible categories accounted for about 20% of its total capital spending. Enbridge witnesses have also questioned the general ability of price cap plans to fund capital investments.

To gauge the consequences for X factor design of Y factoring the proposed capital spending categories we recalculated the TFP trends of the utilities in our U.S. sample leaving 20% of capital expenditures. Using COS capital costing we found that if the utilities could reduce their capital spending by 20%, their TFP growth would accelerate by 31 basis points on average, reaching an average annual growth rate of 1.92%.

We also did a run where capex was set at zero for all utilities during the sample period. In this event, TFP growth averaged 4.53% annually. This rate of growth exceeds the pace of O&M input productivity due to the productivity-enhancing effect of declining rate base. It suggests that the entirety of the positive growth in a PCI for a gas utility goes to fund capital spending. In the absence of such spending the PCI would, in the general case, decline.

APPENDIX

This appendix contains additional details of our research. Section A.1 addresses the output quantity indexes. Section A.2 addresses price indexes. Section A.3 addresses the input quantity indexes, including the calculation of capital cost. Section A.4 discusses the calculation of capital cost. Section A.5 addresses our method for calculating TFP growth rates and trends. Section A.6 discusses the econometric cost research. The mathematical logic for our approach to PCI design is detailed in section A.7. The mathematical basis for peer group selection is discussed in section A.8. The qualifications of the authors are discussed in A.9.

A.1 Output Quantity Indexes

A.1.1 Index Form

The output quantity indexes used to measure cost efficiency trends were determined by the following general formula.

$$\ln\left(\text{Output Quantities}_t \Big/ \text{Output Quantities}_{t-1}\right) = \sum_i \left(SE_i\right) \cdot \ln\left(Y_{i,t} \Big/ Y_{i,t-1}\right). \qquad [A1]$$

Here in each year t,

$Output\ Quantities_t$ = Output quantity index

$Y_{i,t}$ = Amount of output i.

SE_i = Share of output measure i in the sum of the estimated output elasticities.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the output subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. The weight for each output quantity measure was its share in the sum of our econometric estimates of the estimated cost elasticities for the measures.

The revenue-weighted output quantity indexes were calculated with the following alternative formula.

$$\ln\left(\text{Output Quantities}_{t} \Big/ \text{Output Quantities}_{t\text{-}1}\right) = \sum_i \left(SR_i\right)\cdot \ln\left(Y_{i,t} \Big/ Y_{i,t-1}\right). \qquad [A2]$$

Here in each year t,

$Y_{i,t}$ = aggregate measure of billing determinant i for companies in the region

$SR_{i,t}$ = share of billing determinant i in total base rate revenue.

The growth rate of the summary output index is once again a weighted average of the growth rates of the output quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years.

The revenue weights in such an index can in principal be fixed or flexible. Flexible weights produce a more accurate estimate of the impact of output growth on revenue. However, fixed weights are more consistent with a restriction on the redesign of rates, which can materially alter the revenue shares of individual rate elements. In this study, we therefore used fixed revenue weights for each company in PCI calibration. The weights for each company were based on the shares of its rate elements in base revenue in 2005.

A.1.2 Weather Normalization of Volume Data

The U.S. residential and commercial volumes used in this study were adjusted for weather volatility. Our method for accomplishing this has changed since the June report. The weather adjustment still involved two steps. In the first, we used regional US delivery volume and HDD data to estimate the impact of HDDs on residential and commercial deliveries.[49] In particular, we regressed the logarithm of residential and commercial deliveries of individual sample distributors on the mean-scaled and logged values of HDDs, the number of customers, and a quadratic term of HDDs. Additionally, we included firm specific binary ("dummy") variables. Since our sample includes observations on 36 U.S. gas distributors, which are indicated in the regression by D and the respective ID numbers that we give each utility, we dropped the dummy for the last utility so as to retain an intercept term in the regression. The sample includes observations from 1994-2004 for each utility. Thus, the regression model used was:

[49] All delivery and heating degree days data were logged. In addition, the HDD data were mean-scaled prior to estimation.

$$\ln(YVRC_{it}) = \alpha_o + \alpha_N * \ln(N_{it} / \overline{N}) + \alpha_{HDD} * \ln(HDD_{it} / \overline{HDD})$$
$$+ \alpha_{Hdd*HDD} * 0.5 * \ln(HDD_{it} / \overline{HDD}) * \ln(HDD_{it} / \overline{HDD})$$
$$+ \sum_{i=1}^{N-1} \alpha_{Di} * DUM_i + \alpha_t * t + \varepsilon_{it} \qquad i = 1...N, \; t = 1...T$$

The term on the left hand side of this equation is the logarithm of residential and commercial deliveries for firm *i* in year *t*. The first term on the right hand side is a parameter for the constant term. The second term is the mean-scaled and logged value of the number of customers while the third term is a similarly transformed value of HDDs. Mean-scaling is indicated by division by average values of customer numbers and HDDs, which are signified by the terms with bars over them. The fourth term is the quadratic term of HDDs. The fifth set of terms specify firm specific dummies for the first N-1 firms while the sixth term captures the trend in residential and commercial deliveries over the sample period. The last term is the stochastic term of the regression.

Table 18 provides the parameter estimates from the regression undertaken using the US data. While the signs of the coefficients indicate the direction of the effect of the right hand side variables on volume, the magnitudes reflect the extent of these effects. Since we specified a mean-scaled log-log model, the parameter estimates can be interpreted as elasticities. For instance, the coefficient of the HDD variable indicates that, for a 1% increase in HDD, residential and commercial deliveries increase by 0.441%. In addition, the second order term for HDDs are positive indicating that increases in residential and commercial deliveries are higher at higher HDD values. The customer numbers control for scale effect. The negative parameter estimate of the trend captures the declining value of average residential and commercial deliveries. We note that all the parameter estimates, except for the time trend, are statistically significant at least at the 90% confidence level.

In step two of the exercise, we weather normalize the residential and commercial delivery volumes by removing the effect of actual HDDs and using instead the effect of predicted HDDs over the ten year sample period. The values for the predicted HDDs are obtained from an auxiliary regression that specifies the log of HDDs as a function of time and firm dummies. This auxiliary regression captures the effect of a secular trend in HDDs over the years of the sampled period. This allows us to adjust gas consumption for declining HDDs over the years. The effective weather normalization formula that we use can be specified as follows:

Table 18

Econometric Model For Weather Normalization

VARIABLE KEY

yvrc = Log of Residential and Commercial Throughput
HDD = Log of Heating Degree
N = Log of the Number of Customers
D1 - D53 = Firm Specific Dummy Variables

Dependent Variable: yvrc

Explanatory Variables	Parameter Estimate[1]	T-Statistic	Explanatory Variables	Parameter Estimate	T-Statistic	Explanatory Variables	Parameter Estimate	T-Statistic
constant	12.169	72.225	**D15**	-1.003	-3.104	**D37**	-1.389	-4.301
HDD	0.441	9.587	**D17**	-0.130	-1.040	**D38**	-1.254	-3.585
HDDHDD	0.185	3.717	**D21**	-0.993	-3.688	**D40**	-0.870	-3.942
N	0.616	6.839	**D22**	-0.856	-3.601	**D41**	-0.942	-3.589
D1	-0.791	-3.862	**D23**	-0.397	-3.200	**D42**	-0.459	-3.520
D2	-1.472	-3.686	**D24**	-1.014	-4.049	**D43**	-0.684	-3.511
D3	-0.948	-3.357	**D26**	-0.241	-1.399	**D44**	-1.325	-4.296
D6	-1.127	-3.566	**D27**	-0.288	-2.168	**D45**	-0.876	-3.998
D7	-0.800	-2.450	**D28**	-0.296	-1.964	**D46**	-0.670	-3.198
D9	-0.282	-1.794	**D29**	-0.963	-4.040	**D49**	-0.143	-2.154
D10	-0.513	-2.381	**D30**	-0.910	-2.782	**D53**	-0.889	-5.124
D11	-1.067	-3.081	**D31**	-0.085	-0.722	**TREND**	-0.003	-1.366
D12	-0.726	-3.131	**D34**	-0.175	-0.977			
D13	-0.819	-3.284	**D36**	-0.902	-4.166			

sample period:	1994-2004
Adjusted R-squared:	0.993
Number of Observations:	396

[1] The HDD and N parameters are the elasticities of volume with respect to each variable due to the double log form of the model.

$$\ln(YVRC_{it})^{normalized} = \ln(YVRC_{it}) + \hat{\alpha}_{HDD} * \ln\left(H\hat{D}D_{it} / HDD_{it}\right)$$

where $\hat{\alpha}_{HDD}$ is the HDD parameter estimate from the within estimation and $H\hat{D}D_{it}$ is the predicted value of HDD from a model where it is specified as a function of time.

As already mentioned, weather normalization adjusts actual values for HDDs' deviation from trend, which is captured by the HDD parameter estimate multiplied by the fitted residual of the log of HDD on trend and firm dummies. The logged normalized values of residential and commercial deliveries are then exponentiated to obtain the actual normalized values of these deliveries.

In applying this new method to the volumes of Enbridge and Union we discovered that our results were very similar to those of the companies in both cases. To the extent that there are differences we believe that the companies' estimates of weather normalized volumes are likely to be more accurate. We accordingly used the company figures in the latest research. Union Gas does not normalize its transmission volumes. We considered the normalization of these volumes using our methodology but found no statistical support for the undertaking.

A.2 Price Indexes

The summary input price indexes used in this study are of Törnqvist form. This means that the annual growth rate of each index is determined by the following general formula:

$$\ln\left({Input\ Prices_t} \Big/ {Input\ Prices_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(SC_{j,t} + SC_{j,t-1} \right) \cdot \ln\left({W_{j,t}} \Big/ {W_{j,t-1}} \right). \qquad [A3]$$

Here for each company in each year t,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category j

$SC_{j,t}$ = Share of input category j in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. Data on the average shares of each input in the applicable total cost of distributors during the two years are the weights.

A.3 Input Quantity Indexes

A.3.1 Index Form

The summary input quantity index for each company was of Törnqvist form.[50] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(SC_{j,t} + SC_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \quad [A5]$$

Here for each company in each year *t*,

$Input\ Quantities_t$ = Input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$SC_{j,t}$ = Share of input category *j* in applicable total cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of the utility during these years are the weights.

A.3.2 Input Quantity Subindexes

The general approach to quantity trend measurement used in this study relies on the theoretical result that the growth rate in the cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. In that event,

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j . \qquad [A6]$$

A.4 Capital Cost

The service price approach to the measurement of capital cost has a solid basis in economic theory and is widely used in scholarly empirical work.[51] It facilitates the use of benchmarking of cost data for utilities with different plant vintages. In this section, we

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[50] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

[51] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

explain the calculation of capital costs, prices, and quantities using the geometric decay and COS service price methods.

A.4.1 Geometric Decay

In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,t-1}$).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [A7]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market.

In this study there is only one category of plant. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering as well as general plant. In constructing capital quantity indexes we took 1983, 1985 and 1989 as the benchmark or starting years for the U.S. utilities, Union, and Enbridge respectively. These are the earliest years for which the requisite data are available.

Our calculations of the capital cost and quantity in the benchmark year are based on the net value of plant. The capital quantity index in the base year is the inflation adjusted value of net plant in that year. We calculated this by dividing the net plant (book) value by an average of the values of a construction cost index for a period ending in the benchmark year. The construction cost index (WKA_t) used in the U.S. calculations was the regional Handy-Whitman index of gas utility construction costs for the relevant region.[52] The construction cost index used in the Ontario calculations was, as noted above, a deflator for Canada's gas distribution capital stock prepared by Stats Canada.[53]

For all companies, the following general formula was used to compute subsequent values of the capital quantity index:

[52] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[53] No analogous index of the cost of constructing Canadian gas distribution systems is, apparently, available.

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [A8]$$

Here, the parameter d is the economic depreciation rate and $VI_{j,t}$ is the value of gross additions to utility plant. The 3.7% annual depreciation rate was based on a depreciation study provided by Union.

The generic formula for capital service price indexes based on geometric decay that were used in the IPD calculations is

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot I_t + (WKA_t - WKA_{t-1}). \qquad [A9]$$

We restated this as

$$WKS_t = d \cdot WKA_t + WKA_{j,t-1}\left[I_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A10]$$

The first term in [A10] corresponds to the cost of depreciation. The second term captures the opportunity cost of capital ownership net of capital gains. The term in brackets is the real rate of return on capital. This bracketed term was smoothed by taking a three year moving average of its values. The term I_t is the nominal rate of return to capital.

A.4.2 COS

This section of the Appendix discusses the alternative COS approach to the calculation of capital costs and quanties. The basic idea is to decompose the cost of capital as computed under traditional COS accounting into a price and a quantity index. The hallmarks of this accounting approach are straight line depreciation and book (historic) valuation of plant.

Glossary of Terms

For each utility in each year, t, of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year t-s

WKA_{t-s} = Cost per unit of plant construction in year t-s (the "price" of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} \big/ WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions in year t-s

VK_t = Total value of plant at the end of last year

N = Average service life of plant

WKS_t = Price of capital service

Basic Assumptions

The analysis is based on the assumption that depreciation and opportunity cost is incurred in year t on the amount of plant remaining at the end of year t-1, as well as on any plant added in year t. This is tantamount to assuming that plant additions are made at the beginning of the year. We make this assumption to increase the sensitivity of the capital price index to the latest developments in construction costs.

Theory

The non-tax cost of capital is the sum of depreciation and the opportunity cost paid out to bond and equity holders:

$ck_t = ck_t^{opportunity} + ck_t^{depreciation}$.

Assuming straight line depreciation and book valuation of utility plant, the cost of capital can be expressed as

$$
\begin{aligned}
ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s}\left(1/N\right) \cdot a_{t-s} \\
&= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s}\right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_t}
\end{aligned}
\quad [A11]
$$

where

$xk_t = \sum_{s=0}^{N-1} xk_{t-s}$.

Under straight line depreciation we posit that in the interval $\left[N-1, 0\right]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \qquad [A12]$$

The formula for the capital quantity index is thus

$$xk_t = \sum_{s=1}^{N-1} \frac{N\text{-}S}{N} a_{t-s} \ . \qquad [A13]$$

The size of the addition in year t-s of the interval (t-1, t-N) can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \qquad [A14]$$

Equations [A11] and [A14] together imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t \ + \ xk_t \cdot \sum_{s=0}^{N-1} \ \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\ &= xk_t \cdot WKS_t \end{aligned} \qquad [A15]$$

where

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_{t-1}^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot I_t \ + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \qquad [A16]$$

It can be seen that the cost of capital is the product of a capital service price and a capital quantity index. The capital service price in a given year is a function of the construction cost index values in the *N* most recent years (including the current year). The importance of each WKA_{t-s} depends on the share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share is larger the more recent the plant addition year (since there is less depreciation) and the larger the plant additions in that year. Absent a decline in I, *WKS* is apt to rise each year as the WKA_{t-s} for each of the *N* years is replaced with the generally higher value for the following year. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[54]

A.5 TFP Growth Rates and Trends

The annual growth rate in each regional TFP index is given by the formula

[54] Recall that the depreciation rate is constant under the geometric decay approach to capital costing.

$$\ln\left(\frac{TFP_t}{TFP_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A17]$$

The long run trend in each TFP index was calculated as its average annual growth rate over the sample period.

A.6 Econometric Cost Research

In this study, an econometric cost model was used to provide weights for the output quantity indexes and to estimate a target rate of TFP growth for Enbridge and Union. We provide details of the econometric research in this Appendix section.

A.6.1 Cost Models

A cost model is a set of one or more equations that represent the relationship between cost and external business conditions. Business conditions are defined as aspects of a company's operating environment that affect its activities but cannot be controlled. Models can in principle be developed to explain total cost or important cost subsets such as O&M expenses. In this study, total cost models were developed to support the TFP research.

Economic theory can be used to guide cost model development. According to theory, the minimum total cost of a firm is a function of the amount of work that it performs and the prices it pays for capital, labour, and other production inputs. The amount of work performed can be multidimensional and may require several variables for effective measurement. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, it predicts that a firm's cost will typically be higher the higher are input prices and the greater is the amount of work performed.

A.6.2 Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. A simple example of a linear cost model is

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t} \quad \text{[A18]}$$

Here, for each firm h in year t, cost is a function of the number of customers served ($N_{h,t}$), the prevailing wage rate ($W_{h,t}$), and an error term ($e_{h,t}$). Here is an analogous cost model of double log form.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t}\,. \quad \text{[A19]}$$

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. It is also noteworthy that in a double log model, the elasticities are *constant* across every value that the cost and business condition variables might assume.[55]

A more sophisticated translog functional form was used in the research supporting the first draft of this report.[56] This very flexible function is common in econometric cost research and, by some accounts, the most reliable of several available flexible forms.[57] Here is a cost function of translog form that is analogous to [A18] and [A19].

$$\begin{aligned}\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ + a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} + e_{h,t}\end{aligned} \quad \text{[A20]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each translogged business condition variable to differ at different values of the variable. This would permit the incremental economies of scale from output growth to diminish (or increase) at larger operating scales. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable.

In attempting to operationalize the use of company specific elasticities in our calculations we discovered that the translog cost function generated some unreasonable

[55] Cost elasticities are not constant in the linear model that is exemplified by equation [A17].

[56] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[57] See Guilkey (1983), et. al.

values for these. The reasons for this include multicollinearity between the output variables and perhaps also a sample of inadequate size. Preservation of the full translog form is, in our view, less important than including several measures of output in the cost model. We experimented with several alternative specifications and finally settled on one that differed from the translog form only in excluding the "output interaction" terms. We believe that this approach preserves as much flexibility as possible in the cost model while still permitting the multidimensional output specifications that are needed in gas utility cost research.

The general form of this function is captured by the following formula:

$$\begin{aligned}\ln C &= \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \alpha_j \ln W_j \\ &+ \frac{1}{2}\left[\sum_i \gamma_i \ln Y_i \ln Y_i + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\ &+ \sum_i \sum_j \gamma_{ij} \ln Y_i \ln W_j + \sum_\ell \alpha_\ell \ln Z_\ell + \alpha_T T + \varepsilon.\end{aligned} \qquad [A21]$$

Here, Y_i denotes one of several variables that quantify output and W_j denotes one of several input prices. The *Z'*s denote the additional business conditions, *T* is a trend variable, and ε denotes the error term. Note that in order to preserve degrees of freedom and thereby to permit the recognition of additional business conditions we did not translog the Z variables. This practice is common in econometric cost research.

Cost theory requires a well-behaved cost function to be linearly homogeneous in input prices. This implies the following three sets of restrictions on the parameter values.

$$\sum_{j=1}^{J} \frac{\partial \ln C}{\partial \ln W_j} = 1 \qquad [A22]$$

$$\sum_{i}^{M} \frac{\partial^2 \ln C}{\partial \ln Y_i \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots,J \qquad [A23]$$

$$\sum_{n=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_j \partial \ln W_n} = 0 \qquad \forall j = 1,\ldots,J\,. \qquad [A24]$$

These conditions were imposed prior to model estimation.

Estimation of the parameters of equation [A21] is now possible but this approach does not utilize all of the information available in helping to explain the factors that determine cost. Better parameter estimates can be obtained by augmenting the cost equation with some of the cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j*, can be written as:

$$SC_j = \alpha_j + \sum_i \gamma_{ij} \ln Y_i + \sum_n \gamma_{jn} \ln W_n . \qquad [A25]$$

The parameters in this equation also appear in the total cost function. Thus, information about cost shares can be used to sharpen estimates of the cost model parameters.

A.6.3 Estimating Model Parameters

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data on the dependent and explanatory variables.[58] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. The sample used in model estimation can be a time series (consisting of data over several years for a single firm), a cross section (consisting of one observation for each of several firms), or a panel data set that pools time series data for several companies. In this study we have employed panel data because such data are available and their use should enhance the precision of the parameter estimates.

Numerous statistical methods have been established for estimating parameters of economic models. The desirability of each method depends on the assumptions that are made about the probability distribution of the error term. The assumptions under which the best known estimation procedure, ordinary least squares, is ideal often do not hold in statistical cost research.

In this study, we employed a variant of an estimation procedure first proposed by Zellner (1962).[59] If there exists a contemporaneous correlation between the error terms in a system of regression equations, more efficient estimates of their parameters can be obtained using a Feasible Generalized Least Squares (FGLS) approach. To achieve an even better estimator, we corrected as well for heteroskedasticity in the error terms and iterated the procedure to convergence.[60] Since we estimated these unknown disturbance matrices

[58] The estimation of model parameters in this type of model is sometimes called regression.

[59] See Zellner, A. (1962)

[60] That is, given any two estimated consecutive disturbance matrices, if we form another matrix that is their difference, this determinant is approximately zero in the final run.

consistently, our estimators are equivalent to Maximum Likelihood Estimators (MLE).[61] Our estimates thus possess all the highly desirable properties of MLEs.

We used an estimation procedure that corrects for heteroskedasticity because this is a common problem in statistical cost research. A correction for another possible error term problem, autocorrelation, would have involved substantial additional work and was not deemed to be a priority given the many other project challenges. To the extent that autocorrelation is not corrected, we may note that this affects the variance of our estimators but not their bias.

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[62] This does not pose a problem since the MLE procedure is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. It is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates. Once such variables have been removed, the model is re-estimated. An econometric model in which business condition variables are selected in this manner is not a "black box" that confounds earnest attempts at appraisal.

A.6.4 Multicollinearity

Multicollinearity exists in a sample used in econometric research if data for some variables are correlated. In statistical cost research, multicollinearity is especially likely to be encountered in the output variables. The volume of gas delivered by a utility, for instance, is apt to rise with customer growth. To the extent that this is a problem, estimates of the elasticity of cost with respect to the output variables will be less precise in the sense

[61] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[62] This equation can be estimated indirectly if desired from the estimates of the parameters remaining in the model.

that they may be scattered further from their true values. However, they are not apt to be biased.

A conventional remedy for multicollinearity is to pool time series data for numerous companies to create a large panel data set. Comments to this effect are frequently encountered in econometric textbooks. Kennedy, for instance, states that

> Panel data create more variability, through combining variation across micro units with variation over time, alleviating multicollinearity problems. With this more informative data, more efficient estimation is possible.[63]

and that

> Practitioners should…view a multicollinearity problem as equivalent to having a small sample. Realize that getting more information is the only solution.[64]

Baltagi states that

> Panel data give more informative data, more variability, less collinearity among the variables, more degrees of freedom and more efficiency. Time-series studies are plagued with multicollinearity:… With additional, more informative data one can produce more reliable parameter estimates.[65]

Greene states that

> Strategies have been proposed for coping with multicollinearity. Under the view that a multicollinearity "problem" arises because of a shortage of information, one suggestion is to obtain more data. One might argue that if analysts had such additional information available at the outset, they ought to have used it before reaching this juncture.[66]

The value of a large panel data set in gas utility cost research can be seen by returning to our output example. Estimates of output elasticities now depend on the substantial differences in the operating scales of companies in the sample in addition to output trends. Companies with many customers also tend to have large volumes, but this problem is diminished to the extent that we can pool data for companies that serve regions that vary in the extent of industrialization and weather severity. It is thus desirable to use data for a company like Southern California Gas in estimating an econometric cost model

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[63] Kennedy, Peter. *A Guide to Econometrics*, Fifth Edition. MIT Press, Cambridge, 2003, p. 402.
[64] *Ibid*, p. 412.
[65] Baltagi, Badi. *Econometric Analysis of Panel Data*. Wiley, 1995, p. 4.
[66] Greene, William H. *Econometric Analysis*, Fourth Edition. Prentice Hall, 2000, p. 258.

even if the model is being used to set TFP targets in Ontario. If, under these circumstances, models were estimated using subsets of the entire available sample, it would not be surprising if the estimates of the output elasticities were quite different.

To illustrate this principle, we compared the extent of multicollinearity in the full sample to that of samples consisting only of data for utilities that provide only gas services. Using both methods considered, we found that multicollinearity was much more pronounced in the "gas only" sample. The fact that econometric results for this sample are different from those for the full sample is thus evidence of the multicollinearity "disease" without considering the effectiveness of our conventional "cure".

A.6.5 Gas Utility Cost Model

Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. There were three output quantity variables in each model featured in our previous two reports: the number of retail customers, the volume of residential and commercial deliveries, and the volume of other deliveries. Following suggestions from Enbridge consultants we considered as an alternative output variable the sum of transmission and distribution line miles. The introduction of the line miles into the cost model caused the estimate of the other deliveries volume parameter to be insignificant. Moreover, a volume variable was found to be significant only if we added quadratic terms to the line miles index and, effectively, treated it as an output variable. We have treated line miles as an output variable in our power distribution cost research and have elected to do the same in this study. We expect cost to be higher the higher are the values of all three output measures.

Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In these models, we have specified input price variables for capital, labour, and other O&M inputs. These are the same input price variables used in the TFP research. We expect cost to be higher the higher are the values of these variables.

Other Explanatory Variables

Two additional business condition variables were found to be statistically significant cost drivers in the new round of econometric work and included in the cost models.[67] One is the percentage of distribution main not made of cast iron. This is calculated from American Gas Association data. Cast iron pipes were common in gas system construction in the early days of the industry. They are more heavily used in the older distribution systems found in the northeastern United States. Greater use of cast iron typically involves high O&M expenses, and may also involve an expensive program of replacement investment. A higher value for this variable means that a company owns fewer cast iron mains. Hence, we would expect the sign for this variable's parameter to be negative.

A second additional business condition variable in each model is the number of power distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into power distribution. Such diversification will typically lower cost due to the realization of scope economies. The extent of diversification is greater the greater is the value of the variable. We would therefore expect the value of this variable's parameter to be negative.

Each cost model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. A trend variable captures the net effect on cost of diverse conditions, which include technological change in the industry.

Estimation Results

Estimation results for the models developed using GD and COS costing are reported in Tables 19a and 19b, respectively. In both tables, the parameter values for the additional business conditions and for the first order terms of the input prices and output quantities are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The tables shade the results for these useful elasticity estimates for reader convenience.

[67] Variables that were *not* found to be statistically significant cost drivers included frost depth and an earthquake risk measure.

Table 19a

Econometric Model of Gas Utility Base Rate Cost
Geometric Decay

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
V = Total Deliveries
M = Dx and Tx Line Miles
NIM = % Non-Iron Miles in Distribution Miles
NE = Number of Electric Customers
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.209	14.81	**V**	0.119	2.88
LL	-0.582	-4.61	VV	-0.043	-1.10
LK	-0.131	-8.68			
LN	-0.033	-2.51			
LV	0.031	2.74	**M**	0.219	6.80
LM	-0.001	-0.09	MM	0.059	1.22
LTrend	0.006	2.18			
			NIM	-0.959	-13.04
K	0.553	88.01			
KK	0.170	9.93	**NE**	-0.007	-6.53
KN	-0.070	-6.47			
KV	0.039	3.81			
KM	0.039	3.69			
KTrend	0.006	6.20	Trend	-0.010	-4.59
N	0.555	12.17	Constant	8.198	526.53
NN	-0.004	-0.07			
			System Rbar-Squared	0.969	
			Sample Period	1994-2004	
			Number of Observations	396	

Table 19b

Econometric Model of Gas Utility Base Rate Cost:
Cost of Service

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
V = Total Deliveries
M = Dx and Tx Line Miles
NIM = % Non-Iron Miles in Distribution Miles
NE = Number of Electric Customers
Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.215	13.99
LL	-0.702	-5.05
LK	-0.125	-8.48
LN	-0.055	-3.98
LV	0.050	4.25
LM	0.005	0.57
LTrend	0.008	2.76
K	0.522	83.70
KK	0.175	10.97
KN	-0.056	-4.93
KV	0.018	1.68
KM	0.042	4.16
KTrend	0.007	6.88
N	0.610	13.63
NN	0.036	0.65

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
V	0.085	2.02
VV	-0.039	-0.95
M	0.194	6.31
MM	-0.001	-0.01
NIM	-0.949	-12.17
NE	-0.007	-7.07
Trend	-0.012	-5.94
Constant	8.136	513.61
System Rbar-Squared	0.968	
Sample Period	1994-2004	
Number of Observations	396	

The tables also report the values of the asymptotic *t* ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The critical value was 1.645.

The *t* ratios were used in model specification. The output quantities and input prices (which were translogged in model specification) were required to have first order terms with statistically significant parameters. The other variables (which were not translogged) were also required to have statistically significant parameters. We examine here the results for COS costing. The results for GD costing are quite similar. It can be seen in Table 19b that all of the key cost function parameter estimates were statistically significant. Moreover, all were plausible as to sign and magnitude. With regard to the first order terms, cost was found to be higher the higher were the input prices and the two output quantities. At sample mean values of the business condition variables, a 1% increase in the number of customers raised cost by 0.61%. A 1% hike in total throughput raised cost by about 0.09%. A 1% hike in the line miles index raised cost by about 0.19%. The number of customers served was clearly the dominant output-related cost driver. The sum of the elasticities of the output variables was 0.89. This means that simultaneous 1% of growth in all three output dimensions would raise total cost by only 0.89% for a firm with a sample mean operating scale.

The results suggest, importantly, that the scale economies available from incremental output growth do not diminish materially with operating scale. This is due to the fact that the quadratic terms for the output variables are not sizable and positively-signed. The quadratic terms for delivery volumes and line miles are, in fact, negatively signed. Since Enbridge and Union are both large companies facing brisk output growth, they both have good opportunities to realize scale economies and this should materially bolster their productivity growth.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was about 0.52%. This was more than double the estimated elasticity of the price of labour. This comparison reflects the capital intensiveness of the gas distribution business.

The table also reports the system R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.968, suggesting that the explanatory power of the model was high. Please note, however, that high R^2 values are often encountered in cost models estimated using a sample of companies with diverse operating scales.

A.7 Mathematical Basis for the Proposed Price Cap Index

A.7.1 Glossary of Terms

For a given utility or group of utilities let:

P = Index of growth in the prices charged for utility services

W = Index of growth in the prices paid for inputs

X = Index of growth in the amounts of inputs used

Y^E = (cost) elasticity-weighted index of growth in the quantity of outputs

Y^R = revenue-weighted index of growth in the quantity of output

$Cost$ = Total Cost of Service

$Revenue$= Total Revenue

Δ= Growth Rate

A.7.2 Basic Divisia Index Logic

Suppose now that a utility experiences, in the long run, revenue growth that matches its cost growth as in a competitive industry or a utility industry.

$$\Delta Revenue = \Delta Cost \qquad [A26]$$

For *any* enterprise, or group of same, there exist input price and quantity indexes such that the growth of cost is the sum of the growth of the indexes.

$$\Delta Cost = \Delta W + \Delta X \qquad [A27]$$

The weights for these indexes are the shares of the individual inputs in total cost. By analogous logic, there exist output price and quantity indexes such that the growth in revenue is the sum of the growth in the indexes.

$$\Delta Revenue = \Delta P + \Delta Y^R \qquad [A28]$$

The weights for these indexes are the shares of the individual outputs in total revenue. Equations [A26]-[A28] together imply that:

$$\Delta P = \Delta W\text{-}(\Delta Y^{R}\text{-}\Delta X)$$
$$= \Delta W\text{-}\,\Delta TFP^{R} \qquad \text{[A29]}$$

In words, output price growth is the difference between the growth in the input price index and the growth in a TFP index that is calculated using a revenue-weighted output quantity index. This is the logic behind the use of input price and TFP indexes in the design of price cap indexes. A properly designed TFP^{R} index will pick up the impact of declining volume per customer on revenue. A stretch factor is commonly added to the X-factor formula. We omit the stretch factor from the equations in this treatise only for expositional convenience.

Consider next that if *GDPIPI* is used as the inflation measure of the price cap index,

$$\Delta P= \Delta GDPIPI+ (\Delta W\text{-}\Delta GDPIPI) \text{ - } \Delta TFP^{R} \qquad \text{[A30]}$$

This formula is sometimes used in X factor calibration. However, since *GDPIPI* is an index of *output* price inflation, it is reasonable to suppose, using the result in [A29], that:

$$\Delta GDPIPI{=}\Delta W_{Economy} \text{ - } \Delta TFP_{Economy} \qquad \text{[A31]}$$

[A30] and [A31] together imply that:

$$\Delta P= \Delta GDPIPI + \Delta W\text{- } (\Delta W_{Economy} \text{ - } \Delta TFP_{Economy}) \text{ - } \Delta TFP^{R}$$
$$= \Delta GDPIPI - [(\Delta W_{Economy} \text{ - } \Delta W) + (\Delta TFP^{R} \text{ - } \Delta TFP_{Economy})] \qquad \text{[A32]}$$

This explains the focus on input price and productivity differentials in the Union Gas and many other price cap proceedings.

A.7.3 Decomposing TFP^{R}

For simplicity of exposition, let us return for now to the simpler formula in equation [A29]. Denny, Fuss, and Waverman (1984) show that the elasticity-weighted output quantity index, Y^{E}, is a useful output quantity index when the goal of productivity research is to measure progress in *cost* efficiency but not in marketing efficiency. We can use Y^{E} to restate [A29] as

$$\Delta P= \Delta W\text{-}[(\Delta Y^{E} \text{ - } \Delta X) + (\Delta Y^{R}\text{-}\Delta Y^{E})]$$
$$=\Delta W\text{-}[\Delta TFP^{E} + (\Delta Y^{R}\text{-}\Delta Y^{E})]. \qquad \text{[A33]}$$

It can be seen that we have decomposed ΔTFP^R into the sum of the growth in ΔTFP^E ---a measure of *cost* efficiency progress --- and (ΔY^R-ΔY^E), the difference between the growth rates of the two output quantity indexes. The analogous formula in the situation where GDPIPI is the inflation measure is

$$\Delta P = \Delta GDPIPI - (\Delta W_{Economy} - \Delta W) - \{[\Delta TFP^E + (\Delta Y^R - \Delta Y^E)] - \Delta TFP_{Economy}\}$$

$$= \Delta GDPIPI - [(\Delta W_{Economy} - \Delta W) + (\Delta TFP^E - \Delta TFP_{Economy}) + (\Delta Y^R - \Delta Y^E)]\ . \quad \text{[A34]}$$

A.7.4. Rationale for Service-Specific PCIs

Stating the Problem

Suppose that the escalation in the rates of a utility is limited by a summary price cap index. The impact of growth in rates on the growth in revenue is measured by a price index (P^R) that is a revenue-weighted average of the growth in the individual rate elements. Formally,

$$\Delta P^R = \sum_{\ell} \sum_{i} \frac{R_{i\ell}}{R} \Delta P_{i\ell} \quad \text{[A35]}$$

where

R = total revenue

$R_{i\ell}$ = revenue from billing determinant i of service group ℓ

$P_{i\ell}$ = rate element corresponding to billing determinant i of service group ℓ

and the symbol Δ indicates the instantaneous growth rate of a variable.

The growth rate formula for the summary PCI is

$$\Delta PCI = \Delta GDPIPI - (PD + IPD + AU + Stretch)$$

Recalling relation [A30], this can be simplified without loss of generality to[68]

$$\Delta PCI = \Delta GDPIPI - [\Delta TFP^R + (GDPIPI - \Delta W) + Stretch] \quad \text{[A36]}$$

$$= GDPIPI - (\Delta TFP^R + A)$$

where

TFP^R = TFP index with a revenue-weighted output index

$$\Delta TFP^R = \Delta Y^R - \Delta X \quad \text{[A37]}$$

[68] The formulas for the design of the ADJ factor are still relevant if there are PD and IPD terms in the X factor formula.

Y^R = revenue-weighted output index

$$\Delta Y^R = \sum_{\ell} \sum_{i} \frac{R_{i\ell}}{R} \Delta Y_{i\ell} \qquad \text{[A38]}$$

$Y_{i,\ell}$ = total amount of billing determinant i for service group ℓ

X = cost-weighted input quantity index

C_j = cost of input group j

X_j = quantity of input j

ΔW = input price index weighted by the costs actually incurred

Suppose, now, that we want to design caps on rates for particular services or service groups that are consistent with the summary PCI. If PCI_ℓ is the price cap index for service group ℓ, we seek a set of price cap indexes such that

$$\Delta PCI = \sum_{\ell} \frac{R_\ell}{R} \Delta PCI_\ell . \qquad \text{[A39]}$$

One option is to have the same PCI $_\ell$ for all service groups. This is at least consistent with the summary PCI since

$$\sum_{\ell} \frac{R_\ell}{R} \Delta PCI = \Delta PCI \cdot \sum_{\ell} \frac{R_\ell}{R} = \Delta PCI .$$

However, this approach ignores differences in the way that the services that a utility provides affects its TFP growth.

Contributions from Cost Theory

Consider, now, that the impact on the revenue from service group $\ell\,(R_\ell)$ of growth in the billing determinants corresponding to that group is measured by the revenue-weighted output index Y_ℓ^R where

$$\Delta Y_\ell^R = \sum_{i} \frac{R_{i\ell}}{R_\ell} \cdot \Delta Y_{i\ell} . \qquad \text{[A40]}$$

[A38] and [A40] imply that the growth rate formula for Y^R can also be written as follows:

$$\Delta Y^R = \sum_{\ell} \frac{R_\ell}{R} \sum_{i} \frac{R_{i\ell}}{R_\ell} \cdot \Delta Y_{i\ell}$$

$$= \sum_{\ell} \frac{R_\ell}{R} \Delta Y_\ell^R .$$

In words, output growth is a revenue weighted average of growth in the output indexes for the individual service groups.[69]

Consider, next, the effect of growth in the output of each service group ℓ on *cost*. Suppose that the cost of service (*C*) is a function of vectors of output quantities (***Y***) and input prices (***W***)

$$C = g(\mathbf{y}, \mathbf{W})$$

so that

$$\ln C = \ln g(\mathbf{y}, \mathbf{W})\,.^{70}$$

Totally differentiating each side with respect to time we find that

$$\begin{aligned}
\frac{d\ln C}{dT} = \Delta C &= \frac{1}{C}\left(\sum{}_{\ell}\sum{}_{i}\frac{\partial g}{\partial Y_{i\ell}}\frac{dY_{i\ell}}{dT} + \sum{}_{j}\frac{\partial g}{\partial W_j}\frac{dW_j}{dT}\right) \\
&= \sum{}_{\ell}\sum{}_{i}\frac{\partial g}{\partial Y_{i\ell}}\frac{Y_{i\ell}}{C}\frac{1}{Y_{i\ell}}\frac{dY_{i\ell}}{dT} + \sum{}_{j}\frac{\partial g}{\partial W_j}\frac{W_j}{C}\frac{1}{W_j}\frac{dW_j}{dT} \\
&= \sum{}_{\ell}\sum{}_{i}\,\varepsilon_{i\ell}\frac{d\ln Y_{i\ell}}{dT} + \sum{}_{j}\frac{\partial g}{\partial W_j}\frac{W_j}{C}\frac{d\ln W_j}{dT} \\
&\sum{}_{\ell}\sum{}_{i}\,\varepsilon_{i\ell}\Delta Y_{i\ell} + \sum{}_{j}\frac{\partial g}{\partial W_j}\frac{W_j}{C}\Delta W_j
\end{aligned} \qquad [A41]$$

where $\varepsilon_{i\ell}$ is the elasticity of cost with respect to a change in the amount of billing determinant *i* of service group ℓ. Note that $\varepsilon_{i\ell}$ will be larger the greater is the sensitivity of cost to $Y_{i\ell}$ growth and the higher is the level of $Y_{i\ell}$.

Shepherd's Lemma, a condition for cost minimization, holds that

$$\frac{\partial g}{\partial W_j} = X_j\,. \qquad [A42]$$

---

[69] The impact of growth in service group ℓ billing determinants on the growth in total revenue is $\frac{R_\ell}{R}\cdot\Delta Y_\ell^R$.

[70] To simplify the analysis we abstract from the possible existence of additional business condition variables. This complication is addressed in the context of peer group selection in Section A.8.

Equations [A41] and [A42] imply that

$$\begin{aligned}\Delta C &= \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} + \sum_{j} \frac{X_j W_j}{C} \Delta W_j \\ &= \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} + W^{*}\end{aligned} \qquad [A43]$$

where W^* is an input price index in which the cost shares are consistent with cost minimization. Growth in the input quantity index of any firm or industry is the difference between the growth in its cost and the growth in an input price index

$$\Delta X = \Delta C - \Delta W \,. \qquad [A44]$$

Assuming that growth in this input price index is the same as the growth in W^*, equations [A43] and [A44] imply that

$$\Delta X = \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \cdot \Delta Y_{i\ell} + \sum_{h} \varepsilon_{h} \cdot \Delta Z_{h} \,. \qquad [A45]$$

From [A37], [A40], and [A45] it follows that we can restate in the growth of TFP^R as a function of the growth of the outputs of the individual service groups

$$\Delta TFP^{R} = \sum_{\ell} \frac{R_{\ell}}{R} \Delta Y_{\ell}^{R} - \Big(\sum_{\ell} \sum_{i} \varepsilon_{i\ell} \cdot \Delta Y_{i\ell} + \sum_{h} \varepsilon_{h} \cdot \Delta Z_{h}\Big) \,. \qquad [A46]$$

Note that output growth has an effect on cost as well as an effect on revenue.

The ADJ Factor

With this background, we now consider how to design the PCIs for particular service groups. This can be done by establishing X factors for the PCI_{ℓ} growth formulas that differ from the formula for the summary PCI only in featuring a special adjustment term, ADJ_{ℓ}, in the X factor that varies by service group.

The idea behind ADJ_{ℓ} is to adjust the X factor so that it reflects the special contributions of service group ℓ to TFP growth rather than the net impact of all services. Since TFP growth is a function of output growth, this involves a calculation of how the TFP impact of the output growth of the service group differs from the TFP impact of output growth overall. With this approach, the X factor of a service group that does not contribute to the declining use problem would not be sensitive to it.

From [A46], the growth in TFP^R that would result if the utility offered only group ℓ services may be written

$$\begin{aligned}\Delta TFP_\ell^R &= \Delta Y_\ell^R - \textstyle\sum_i \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C_\ell} \cdot \Delta Y_{i\ell} + \textstyle\sum_h \varepsilon_h \cdot \Delta Z_h \\ &= \Delta Y_\ell^R - \frac{C}{C_\ell} \cdot \textstyle\sum_i \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_i}{C} \cdot \Delta Y_{i\ell}\end{aligned} \qquad [A47]$$

Relations [A46] and [A47] imply that the difference between the TFP^R growth of the hypothetical specialized utility and the TFP of the integrated utility is given by the formula

$$\begin{aligned}\Delta TFP_\ell^R - \Delta TFP^R &= \left(\Delta Y_\ell^R - \frac{C}{C_\ell} \cdot \textstyle\sum_i \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell}\right) - \left(\Delta Y^R - \textstyle\sum_\ell \sum_i \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell}\right) \\ &= \left(\Delta Y_\ell^R - \Delta Y^R\right) + \left[\left(\textstyle\sum_\ell \sum_i \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell}\right) - \frac{C}{C_\ell}\left(\textstyle\sum_i \frac{\partial g}{\partial Y_{i\ell}} \cdot \frac{Y_{i\ell}}{C} \cdot \Delta Y_{i\ell}\right)\right] \\ &= \left(\Delta Y_\ell^R - \Delta Y^R\right) + \left(\textstyle\sum_\ell \sum_i \varepsilon_{i\ell} \Delta Y_{i\ell} - \frac{C}{C_\ell} \sum_i \varepsilon_{i\ell} \Delta Y_{i\ell}\right)\end{aligned}$$

It can be seen that we have decomposed this difference into a *revenue* effect and a *cost* effect. The revenue effect captures how the revenue impact of growth in the output of service group ℓ differs from the revenue impact of overall output growth. The cost effect captures how the cost impact of growth in the output of service group ℓ differs from the cost impact of overall output growth. Both terms are essential to the development of just and reasonable ADJs. Service to residential customers, for instance, may require a special X factor because growth in the number of these customers has a disproportionate impact on utility cost in addition to the fact that it involves average use decline. The indicated adjustment to the X factor for a particular service group will be more negative to the extent that it has a disproportionately *small* impact on *revenue* and a disproportionately *large* impact on *cost*.

Note that this formula for ADJ calculation will not achieve consistency with the summary PCI if the current rate design results in a mismatch between the cost and revenue impacts of different service groups. We thus replace the *cost* adjustment term C/C_ℓ with the analogous *revenue* adjustment R/R_ℓ. The proposed formula for each ADJ_ℓ is thus

$$ADJ_\ell = \left[\left(\Delta Y_\ell^R - \Delta Y^R\right) + \left(\sum_\ell \sum_i \varepsilon_i \Delta Y_{i\ell} - \frac{R}{R_\ell}\sum_i \varepsilon_{i\ell}\Delta Y_{i\ell}\right)\right] \qquad [A48]$$

Equations [A35], [A36], [A39], and [A45] together imply that

$$\begin{aligned}
\Delta P^R &= \sum_\ell \frac{R_\ell}{R}\Delta PCI_\ell \\
&= \sum_\ell \frac{R_\ell}{R}\left[\Delta GDPIPI - \left(A + \Delta TFP^R + ADJ_\ell\right)\right] \\
&= \Delta GDPIPI - \left(A + \Delta TFP^R + \sum_\ell \frac{R_\ell}{R}\Delta ADJ_\ell\right) \\
&= \Delta GDPIPI - \left(\begin{array}{l} A + \Delta TFP^R + \\ \sum_\ell \frac{R_\ell}{R}\left(\sum_i \frac{R_{i\ell}}{R_\ell}\Delta Y_{i\ell} - \Delta Y^R\right) - \\ \sum_\ell \frac{R_\ell}{R}\left(\sum_\ell \sum_i \varepsilon_{i\ell}\Delta Y_{i\ell} - \sum_i \frac{R}{R_\ell}\varepsilon_{i\ell}\Delta Y_{i\ell}\right) \end{array}\right) \\
&= \Delta GDPPI - \left(\Delta TFP^R + A\right).
\end{aligned}$$

This formula for the ADJ_ℓ terms thus permits the calculation of service group specific X factors that are consistent with the summary price cap index.

Operationalizing the Theory

How do we operationalize [A48]? Assume that the hypothetical marginal cost of each quantity *i* provided by a specialized service provider is the same as that of the integrated utility. Then for any Y_i and $Y_{i\ell}$

$$\frac{\partial g}{\partial Y_{i\ell}} = \frac{\partial g}{\partial Y_i}$$

and

$$\sum_{\ell} \sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} = \sum_{\ell} \sum_{i} \frac{\partial g}{\partial Y_i} \frac{Y_{i\ell}}{C} \Delta Y_{i\ell}$$

$$= \sum_{i} \frac{\partial g}{\partial Y_i} \frac{Y_i}{C} \sum_{\ell} \frac{Y_{i\ell}}{Y_i} \frac{1}{Y_{i\ell}} \frac{dY_{i\ell}}{dT}$$

$$= \sum_{i} \varepsilon_i \frac{1}{Y_i} \frac{d \sum_{\ell} Y_{i\ell}}{dT}$$

$$= \sum_i \varepsilon_i \frac{d \ln Y_i}{dT}$$

$$= \sum_i \varepsilon_i \Delta Y_i .$$

The ADJ_ℓ formula then simplifies to

$$ADJ_\ell = \left(\Delta Y_\ell^R - \Delta Y^R\right) + \left(\sum_i \varepsilon_i \Delta Y_i - \frac{R}{R_\ell} \sum_i \varepsilon_{i\ell} \Delta Y_{i\ell}\right). \qquad \text{[A49]}$$

Estimates of the elasticities can be obtained for each company from econometric cost research using data for vertically integrated companies. Since

$$\varepsilon_{i\ell} = \frac{\partial g}{\partial Y_{i\ell}} \frac{Y_{i\ell}}{C} = \frac{\partial g}{\partial Y_i} \frac{Y_i}{C} \frac{Y_{i\ell}}{Y_i} = \varepsilon_i \frac{Y_{i\ell}}{Y_i}$$

it is possible to compute estimates of the elasticities corresponding to individual service groups fairly easily from our estimates of the *overall* elasticities. While the methodology involves assumptions, we believe that it generates better results than simpler methods that involve hidden assumptions.

The addition of a line miles variable to the cost function raises the question of how this variable should be treated for purposes of the ADJ calculation since, previously, all quantity variables in the cost model could be assigned to specific services. We assume that line miles are entirely a function of the number of customers that a utility serves. Specifically, we posit that each service is accountable for a share of the total line miles that equals its share of the total number of customers.

A.8 Peer Group Selection

A peer group used to establish a TFP target should consist of utilities facing similar drivers of TFP growth. Mathematical theory and econometric research provide a rigorous basis for identifying these drivers and choosing peer groups. An informal discussion of the theory can be found in Section 2.

Here is a more formal treatment that involves an extension of the reasoning we used in Section A.7 to derive the ADJ factor. The starting point for the analysis is the assumption that the actual cost incurred by a firm is the product of its minimum total cost, C^*, and a term, η, that may be called the inefficiency factor.

$$C = C^* \cdot \eta. \qquad [A50]$$

The inefficiency factor indicates how high the actual cost of a firm is above the minimum attainable level. Equation [A50] implies that the instantaneous growth rate of total cost is the sum of the growth rates of minimum total cost and the inefficiency factor.[71]

$$\dot{C} = \dot{C}^* + \dot{\eta}. \qquad [A51]$$

It is a basic result of economic theory that given a well-behaved production technology, the minimum total cost of an enterprise is a function of various input prices (***W***), output quantities (***Y***), and variables that measure miscellaneous other business conditions (***Z***). The resultant cost function can be represented mathematically as

$$C^* = g(\boldsymbol{W}, \boldsymbol{Y}, \boldsymbol{Z}). \qquad [A52]$$

Note that this model differs from the simplified model used to calculate ADJ factors due to the addition of Z variables. The elasticity of cost with respect to each output variable Y_i is denoted by ε_{Y_i}. The other elasticities and business condition variables are denoted analogously.

Total differentiation of Equation [A52] with respect to time reveals that

$$\dot{C}^* = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_h \varepsilon_{Z_h} \cdot \dot{Z}_h + \sum_j \varepsilon_{W_j} \cdot \dot{W}_j \right) + \dot{g}. \qquad [A53]$$

[71] All growth rates in this discussion are assumed to be instantaneous.

The growth rate of minimum total cost can be seen to be the sum of two terms. The first is the sum of the products of the growth rates of the business condition variables and their corresponding cost elasticities. The second is the proportional shift in the cost function ($\dot{g}$).

Invoking Shephard's lemma once again, equation [A53] may be rewritten as

$$\dot{C}^{*} = \sum_{i} \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_{h} \varepsilon_{Z_h} \cdot \dot{Z}_h + \dot{W}^{*} + \dot{g}. \qquad \text{[A54]}$$

where $\dot{W}^{*}$ is the growth rate of the optimal input price index. We once again assume for simplicity that this equals the growth of the actual input price index ($\dot{W}$)

Let us now define the growth rate of a TFP index (TFP^E) to be the difference between the growth rates of a cost elasticity output quantity index (Y^E) and an input quantity index (X). Formally

$$T\dot{F}P^{E} = \dot{Y}^{E} - \dot{X}\,. \qquad \text{[A55]}$$

The growth rate of the input quantity index is known to be the difference between the growth rates of cost and the (actual) input price index (W).

$$\dot{X} = \dot{C} - \dot{W} \qquad \text{[A56]}$$

Equations [A54] - [A56] imply that

$$\begin{aligned}
T\dot{F}P^{E} &= \dot{Y}^{E} - \left(\dot{C} - \dot{W}\right) \\
&= \dot{Y}^{E} - \left[\left(\sum_{i} \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_{h} \varepsilon_{Z_h} \cdot \dot{Z}_h + \dot{W} + \dot{g} + \dot{\eta}\right) - \dot{W}\right] \\
&= \dot{Y}^{E} - \left[\left\{\sum_{i} \varepsilon_{Y_i} \left[\left(\sum_{i} \frac{\varepsilon_{Y_i}}{\sum_{i} \varepsilon_{Y_i}}\right) \cdot \dot{Y}_i\right] + \sum_{h} \varepsilon_{Z_h} \cdot \dot{Z}_h + \left(\dot{g} + \dot{\eta}\right)\right\}\right] \qquad \text{[A57]} \\
&= \dot{Y}^{E} - \left[\sum_{i} \varepsilon_{Y_i} \dot{Y}^{E} + \sum_{h} \varepsilon_{Z_h} \cdot \dot{Z}_h + \left(\dot{g} + \dot{\eta}\right)\right] \\
&= \dot{Y}^{E} - \left[\Big(\sum_{i} \varepsilon_{Y_i} - 1\Big)\dot{Y}^{E} + \dot{Y}^{E} + \sum_{h} \varepsilon_{Z_h} \cdot \dot{Z}_h + \left(\dot{g} + \dot{\eta}\right)\right] \\
&= \Big(1 - \sum_{i} \varepsilon_{Y_i}\Big)\dot{Y}^{E} - \sum_{h} \varepsilon_{Z_h} \cdot \dot{Z}_h - \left(\dot{g} + \dot{\eta}\right)
\end{aligned}$$

The growth rate of the TFP index has been decomposed theoretically into four terms. The first is the **scale economy effect**. Returns to scale are realized to the extent that incremental scale economies are available and output quantity grows. Incremental scale economies exist if the sum of the cost elasticities with respect to the output variables is less than 1.

The second term measures the effect on TFP growth of growth in the values of the Z variables. We will call this the **other business condition effect**. If the cost elasticity of a given Z variable, *h*, is positive (negative), an increase in the value of the variable will decelerate (accelerate) TFP growth.

The third term measures the effect on TFP growth of the proportional shift in the cost function. It may be called the **technological change effect**. The cost function will shift downward (upward) if cost falls (rises) at given values of the business condition variables. A downward (upward) shift in the cost function will accelerate (decelerate) TFP growth.

The fourth term measures the effect on TFP growth of a change in the inefficiency factor. We will call this the **inefficiency effect**. A decline (increase) in the inefficiency factor will accelerate (decelerate) TFP growth.

Equation (A57) reveals that TFP growth depends on the *growth rates* of outputs and other business condition variables and not on their *levels*. It makes sense, then, to search for peers facing similar growth rates in key business conditions.

PEG used Equation (A57) and the econometric estimates of cost elasticities which it developed for the Board to prepare peer groups for Enbridge and Union rigorously. The econometric research readily provides the estimates needed for the scale economy effect and the parametric trend effect. In principle, other business condition effects could also be included in the model. The econometric research identified three other business conditions: number of electric customers, % of line miles that are not cast iron, and the presence or absence in the service territory of an urban core. With regard to these

- The value of the urban core variable doesn't change.
- Enbridge and Union don't have electric customers
- The estimate on the cast iron variable suggests that reducing cast iron *lowers* cost rather and does not *raise* cost as Enbridge suggests.

Feeling that the cast iron effect might be different in the short run PEG chose not to use this variable in our TFP target research. Since the parametric change effect is similar for all companies and the other two business conditions are not germane, the research suggested that similarity in the scale economy effect was the sole basis for choosing peers. Since

Enbridge and Union are experiencing brisk customer growth, the peers will tend to be companies that also have brisk customer growth.

A.9 PEG Qualifications

A.9.1 Pacific Economics Group

Pacific Economics Group (PEG) is an economic consulting firm with practices in the fields of utility regulation and civil litigation. Our home office is located in Pasadena, California. The chief satellite office is based in Madison, Wisconsin. Five principals of the company are PhD economists and three are current or former faculty members at respected universities. Founding partner Charles Cicchetti is a professor of economics at the University of Southern California. He was previously chair of Wisconsin's Public Service Commission and an economics professor at the University of Wisconsin. Founding partner Jeff Dubin is an economics professor at Cal Tech.

PEG is a leading provider of energy utility performance measurement and IR services. Our personnel have over 40 man years of experience in these areas. This work has required a thorough understanding of the energy industry and the science of performance measurement.

A.9.2 Mark Newton Lowry

Senior author Mark Newton Lowry is the managing partner in PEG's Madison office and directs our North American practice in the areas of IR and statistical benchmarking. His specific duties include the supervision of performance research, the design of IR plans, and expert witness testimony. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin-Madison.

Over the years he has prepared numerous utility performance studies and developed many IR plans. He has testified or filed commentary 14 times on statistical benchmarking, and more than 20 times on industry productivity trends and other IR issues. The venues for this testimony have included California, Georgia, Hawaii, Kentucky, Maine, Massachusetts, Oklahoma, Ontario, New York, Quebec, and British Columbia. His practice has extended beyond our shores to include projects in Asia, Australia, Europe, and Latin America. Dr. Lowry is multilingual and can advise clients in Spanish as well as English.

Before joining PEG, Dr. Lowry worked for several years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of the Regulatory Strategy practice. In total, he has over 16 years of consulting experience in the areas of performance measurement and IR.

His career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory, econometrics, and numerical methods in industry analysis. He has been a referee for several scholarly journals and has an extensive record of professional publications and public appearances.

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