# Price Cap Index Design for Ontario's Natural Gas Utilities

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# EXECUTIVE SUMMARY

The Staff of the Ontario Energy Board issued a report on January 5 of this year detailing its views on a new approach to incentive regulation ("IR") for Enbridge Gas Distribution Inc. ("Enbridge") and Union Gas Limited ("Union"). An approach to IR is envisioned in which rate escalation is limited by price cap indexes ("PCIs"). The formulas driving PCI growth would feature a gross domestic product implicit price index ("GDPIPI") and an X factor consisting 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 (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. Staff has directed PEG to undertake input price and productivity research that would support the selection of values for the PCI formula parameters. This document is the preliminary report on our research.

## Overview of Research

Our research considered the input price, productivity, and usage trends of Enbridge and Union and of 36 U.S. gas utilities for which we have gathered data of good quality. The U.S. 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 also featured an econometric study of gas utility cost drivers that was based on the U.S. data. The research provides the basis for straw man proposals concerning the PCI growth rate formulas.

Established methods and publicly available data from respected sources were employed in the research. The sample period for the U.S. research 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 2000-2005.

We calculated input price and productivity trends 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 in support of PCI design. It features replacement (current dollar) valuation of utility plant and a constant rate of depreciation.
- Cost of service ("COS") This is a new approach to capital costing that 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. Input price and productivity indexes computed using COS costing tend to be more sensitive to recent investment activity.

Our research culminated in straw man proposals for the X factor of the summary PCI for each company. At the request of Board Staff, we also developed straw man PCIs for certain service groups. These were identical to the summary PCIs save for the addition of a service group-specific adjustment terms to the X factor. Absent further research, we believe that our straw man proposals are just and reasonable.

## Key Results

Here are the straw man proposals for the summary PCIs.

***Summary PCIs***

| | Geometric Decay | | COS | |
|---|---|---|---|---|
| | Enbridge | Union | Enbridge | Union |
| Productivity Differential | 0.00 | 0.26 | -0.01 | 0.37 |
| Input Price Differential | -0.16 | -0.33 | -0.37 | -0.35 |
| Average Use Factor | -0.49 | -0.73 | -0.49 | -0.73 |
| Stretch Factor | 0.46 | 0.30 | 0.46 | 0.30 |
| **X Factor** [A = sum of above] | **-0.19** | **-0.50** | **-0.39** | **-0.41** |
| Recent GDPIPI Trend [B] | 1.77 | 1.77 | 1.77 | 1.77 |
| **PCI** [B-A] | **1.96** | **2.27** | **2.16** | **2.18** |

It can be seen that both capital costing approaches would sanction PCI growth that is a little above but broadly similar to the growth in the GDPIPI FDD. Ontario gas consumers would, in other words, experience escalations in rates for gas utility services that are similar to the general inflation in the prices of final goods and services paid by Canadians.

Here are the PCIs for individual service groups that result from our calculations using GD capital costing. Separate PCIs have been designed for all rate classes that include service to residential customers. We calculate indicated PCI growth for each group by taking the difference between the recent trend in the GDPIPI and the straw man X factors.

***Service Group PCIs***

| Company | Service Group | Recent GDPIPI Trend [A] | Sum of Common X Terms [B] | ADJ [C] | Total X Factor [D]=B+C | Indicated PCI Growth [A]-[D] |
|---|---|---|---|---|---|---|
| Enbridge | Rate 1 | 1.77 | -0.19 | -0.74 | -0.93 | 2.70 |
| | Nonresidential | 1.77 | -0.19 | 1.36 | 1.17 | 0.60 |
| Union | Rate M2 | 1.77 | -0.50 | 0.37 | -0.13 | 1.90 |
| | Rate 01 | 1.77 | -0.50 | -0.32 | -0.82 | 2.50 |
| | Nonresidential | 1.77 | -0.50 | -0.52 | -1.02 | 2.79 |

Results for the Union service groups must be interpreted cautiously since rates M2 and 01 both contain a mix of residential and business customers.

## Input Price Differential

We compared the input price trends of Ontario gas utilities to that of Canada's economy using both capital costing methods. The comparisons proved challenging due to the special circumstances of rapid growth in gas utility construction costs and the considerable decline in the cost of funds that occurred in 2004 and 2005. The combination of these conditions caused the GD capital service price index to fall sharply during these years.

The events of the 2004-2005 period are, in our opinion, unlikely to repeat themselves during the prospective IR plan period. To exclude this atypical development we chose the 1993-2002 period to compare the input price trends of the industry and the economy when using the GD approach to capital costing. We found that the appropriate input price differentials for Enbridge and Union were -0.16% and -0.33% respectively.

Using the alternative COS approach to capital costing we found that there was no need to choose a sample period with an end date before 2005. We chose, instead, the 1998-2005 period as one with a similar weighted average cost of funds in the start and end years. The appropriate input price differentials for Enbridge and Union were broadly similar, -0.37% and -0.35% respectively.

**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. The chosen targets were compared to the multifactor productivity ("MFP") trends of the Canadian private business sector to calculate the PDs for each company. The TFP trends of Enbridge and Union were calculated using both the GD and COS approaches to capital costing. Under the GD approach the annual TFP growth of Enbridge and Union averaged 1.03% and 1.98% respectively. Using COS capital costing, the TFP growth of Enbridge and Union annually averaged 0.88% and 1.93%, respectively. The productivity of Enbridge in the use of operating and maintenance ("O&M") inputs slowed materially in 2003 upon the expiration of the multi-year IR plan.

We used the research on the TFP trends of U.S. utilities to establish the specific TFP targets used in X factor design. External targets are generally preferable to company specific TFP trends. Our research suggested that U.S. results are quite useful in the selection of targets for both Ontario utilities.

Research of two kinds was undertaken to select appropriate target rates of TFP growth for Enbridge and Union from the U.S. results. One approach was to calculate the average TFP trends of peer groups consisting of U.S. companies with similar opportunities to realize economies of scale. Over the full 1994-2004 sample period in our U.S. sample, the Enbridge peer group averaged 1.34% annual TFP growth, modestly above the company's actual 2000-2005 trend. The Union peer group averaged 0.94% annual TFP growth, well below Union's actual trend.

Our second approach to establishing TFP growth targets was to calculate the TFP growth that can be predicted using our econometric estimates of the elasticity of cost with respect to output growth. The indicated productivity targets for Enbridge and Union were 1.37% and 1.29%, respectively. Our econometric research which is based on GD costing, did not provide strong support for the notion that Enbridge needs a special X factor adjustment to help finance the replacement of cast iron mains.

To stimulate discussion, we propose as a just and reasonable straw man that the Enbridge TFP target be set at the 1.37% econometric projection. As for Union, it is difficult to ascertain to what degree its comparatively rapid TFP growth between 2000 and 2005 is due to good management and to what degree it is due to its special circumstances as a major transmission and storage operator. We conclude that its productivity growth target should be less than the pace that Union has achieved in recent years but may reasonably be somewhat higher than the TFP trend of its peer group. Our straw man proposal is that the productivity target for Union be to set at 1.63%, halfway between the econometric TFP trend projection of its peer group and its own recent trend using GD capital costing. The sum of Union's productivity target and any stretch factor assigned should, in our opinion, not be allowed to exceed its recent actual trend. The analogous straw man TFP growth targets using COS capital costing are 1.22% for Enbridge and 1.58% for Union.

The productivity differentials that follow from these recommendations depend on the productivity growth trend for the Canadian economy during the period used in the input price comparisons. The trend in the multi-factor productivity of Canada's private business sector was 1.37% during the 1993-2002 period used in the GD input price comparison and 1.21% during the 1998-2005 period used in the COS comparison. Using GD costing, the straw man productivity differential for Enbridge is thus -0.00% (1.37 – 1.37). The straw man productivity differential for Union is 0.26% (1.63 – 1.37). Using COS costing, the straw man productivity differentials for Enbridge and Union are 0.01% (1.22-1.21) and 0.37% (1.58-1.21) respectively.

## 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 customer response to higher natural gas prices. This trend has increase the need of gas utilities for rate escalation. The trend affects rates for different customer rate classes differently. Heat-sensitive loads are primarily in the residential and commercial rate classes. Growth in the number of customers is the principle driver of higher gas utility cost other than input price inflation.

The AU factor was calculated as the difference between the revenue-weighted and cost-weighted elasticity output indexes. For Enbridge, the AU factor is –0.49% which is modestly below the US norm of -0.86. For Union, the AU factor was -0.73, very similar to the US norm.

## Stretch Factor

The stretch factor term of the X factor reflects expectations concerning the potential for better performance under the stronger incentives that may be generated by the IR plan. We have relied on two sources in developing our straw man stretch factor proposals. 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 this 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 stylized regulatory systems.[1] By comparing the performance expected under an approximation to the company's current system to that expected under an approximation of the envisioned 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 between the company and its customers.

Our research suggests that there is no reason not to assign Enbridge and Union stretch factors that are in the vicinity of the 0.5% precedential norm. We also find that there may be grounds to assign different stretch factors to the two utilities. We, accordingly,

[1] Details of our incentive power research will be released in a later document.

suggest a 0.46% straw man stretch factor for Enbridge and a 0.30% straw man stretch factor for Union.

**Price Caps for Service Groups**

Price caps for specific service groups were established by calculating X factors that featured five terms: the four from the summary PCI and a special adjustment term, ADJ, that varies by service 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 the growth the utility's base rate revenue and cost. A service class that makes an unusually large contribution to unit cost growth will then be more likely to have a negative ADJ that makes the X factor smaller so that the PCI for the group rises more rapidly. As a just and reasonable straw man, we propose that there be separate PCIs for all of the rate classes that contain residential customers. All other service classes of Enbridge and Union would be subject to common company-specific PCIs. In the table below, we present the ADJ factors for each service group and a notion of the growth trend of the resultant PCIs.

# 1. INTRODUCTION

The Ontario Energy Board ("OEB") has for many years been interested in incentive regulation ("IR") for its jurisdictional utilities. Enbridge, 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 gas utility regulation in Ontario. In its final report on the Forum the Board found that its regulatory goals are best served by multiyear IR plans with annual rate adjustment mechanisms designed with the aid of index research .[2] 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".[3]

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.

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[2] OEB, *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* March 2005.
[3] *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 that included an initial proposal for an IR approach. Staff sees merit in a price cap approach to IR. The terms of IR plans would include a base year and five further years in which rates would be permitted to escalate. The GDP-IPI FDD is proposed as the PCI inflation measure. The PCI formulas would also feature 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 ["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 has directed PEG to undertake index research that would support the design of PCIs for Enbridge Gas Distribution Inc. ("Enbridge") and Union Gas Limited ("Union"). The study addressed the input price and productivity trends of Enbridge, Union, and a group of U.S. gas utilities.

This document reports on our PCI research for Board staff. 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 of IR rate adjustment mechanisms. The rationale for such research, which employs index logic, provides the basis for the PD, IPD, and DU terms in Staff's proposed price cap indexes. It also sheds light on the best indexing methods for choosing these key plan parameters.

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 compare 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 are the major classes of base rate inputs used by gas utilities.

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 cost of distribution and customer services is 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.[4] 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 be greater the more rapid is output growth and the smaller is the initial operating scale.

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 (M&S) 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.

A fourth important source of TFP growth is changes in the miscellaneous business conditions other than input price and productivity 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.

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

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[4] This section relies heavily on research detailed in Denny, Fuss, and Waverman (1981).

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. 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.

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 summarize the trends in the prices of numerous products by taking weighted average of the price trends for major product groups. An index of trends in the rates charged by a utility uses revenue shares as weights because these weights capture the impact of input price growth on cost.

## 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. Moreover, 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 accelerated productivity growth due to the stronger performance incentives of the IR plan.[5] A PCI is then *calibrated* to track the industry unit cost trend to the extent that

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

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

A properly designed PCI provides automatic adjustments for trends in a wide array of external business conditions that affect the unit cost of utility operation. It can therefore 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.

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

It follows that the trend in an industry's *unit* cost is the difference between the trends in industry input price and TFP indexes.[6]

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

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

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

An important issue in the design of a PCI is whether it should be designed to 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 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 prices accelerate (decelerate). 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

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

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

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 U.S. 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, a sample period suitable for calculating the recent long run trend can be chosen using research on the drivers of TFP index volatility. 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. [7]

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

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

of PBR for utilities. Higher regulatory risk can raise the cost of funds and reduce thereby the net benefits of PBR.

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. For example, the rate of return on capital depends on the state of the economy and on expectations regarding future price inflation.[8] From the late 1970s through the mid 1980s, for instance, bond yields 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 exporting countries 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 historical 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

[8] 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.

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 Productivity and Input Price Differentials

Resolved that the price inflation index should track recent input 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 industry-specific inflation measures in rate adjustment indexes. Such a measure was used in the world's first large scale rate indexing plan, which applied to U.S. railroads. Staff of California Public Utilities Commission ("CPUC") developed industry specific inflation measures that have been used in several IR plans. OEB staff chose an industry specific inflation measure, which it called the "IPI" for the first price cap plan for jurisdictional 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 GDP-IPI FDD. This is 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.

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 GDP-IPI. In that event we can restate relation [9] as

$$trendPCI = trendGDPIPI - \left(\text{trend TFP} + (trendGDPIPI - \text{trend Input Prices}) + Stretch\ \text{Factor}\right) \quad [10]$$

It follows that the PCI can still conform to the industry unit cost standard provided that the X factor effectively corrects for any tendency of GDPIPI growth to differ from industry input price growth. The difference between the trends in the GDPIPI and industry input prices can be substantial in

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.

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

Provided that 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:

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

It follows that when the GDP-IPI 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 above, 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. 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 distribution revenue typically depends chiefly on the growth in delivery volume whereas growth in distribution cost 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.

$$\text{trend PCI} = \text{trend GDPIPI}$$
$$- \begin{bmatrix} \left(\text{trend TFP}^{\text{Industry}} - \text{trend TFP}^{\text{Economy}}\right) \\ + \left(\textit{trend}\ \text{Input Prices}^{\text{Economy}} - \text{trend Input Prices}^{\text{Industry}}\right) + \\ \left(\textit{trend}\ \text{Output}^{\text{Revenue-Weighted}} - \text{trend Output}^{\text{Elasticity-Weighted}}\right) + \textit{Stretch} \end{bmatrix} \quad [13]$$
$$= trendGDPIPI - (PD + IPD + DU + Stretch).$$

The average use 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.

## 2.3 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. When GDPIPI is used as the PCI inflation measure, the X factor can be designed to conform to the industry unit cost standard that contains four terms: PD, IPD,AU,and Stretch.
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
4. The complexity of this approach to X factor design results from the decisions to use GDPIPI as the inflation measure and to separate the effects on PCI growth of

trends in cost efficiency and average use. We can, if desired, eliminate the AU term by using a revenue-weighted output index to measure TFP. We can consolidate the PD and IPD term into a single term that reflects the difference between the trends in GDPIPI and industry-specific input prices. We can, finally, eliminate even this term by using an industry specific inflation measure.

# 3. EMPIRICAL RESEARCH

This section presents an overview of our research on the input price and productivity trends of Ontario and U.S. gas utilities. We begin by discussing data sources and the definition of cost, topics that are equally relevant to the input price and productivity research. We then discuss in detail our research on productivity, declining use, and input price trends, the stretch factor, and the design of PCIs for particular service groups. The section concludes with an explanation of how research in each of these areas was used to construct straw man price cap indexes applicable to general services and other services. 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 U.S. 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 U.S. gas utilities file these annual reports with the American Gas Association.[9]

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. Compliance with this system is mandatory for FERC-regulated utilities but not for the companies in our sample, which are in all cases state-regulated. Gas distribution

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

operating data from state reports are also compiled by commercial venders such as Platts. We obtained the 2004 operating data for this study from the Platts *GasDat* package.

Other sources of data were also employed in the U.S. research. Data on the delivery volumes and customers served by U.S. gas utilities were obtained from Form EIA 176. The corresponding data for contract demands and base rate revenues are not available from this source or any other U.S. source we are aware of. Data on U.S. 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 U.S. gas and electric utilities. Other sources of input price data include R.S. Means and Associates; the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor; and the Energy Information Administration ("EIA") of the U.S. Department of Energy.

Our TFP trend calculations are based on quality data for 36 U.S. utilities. The sample includes most of the larger utilities.[10] The sampled utilities are listed by region in Table 1. Inspection of the table reveals that they account for above 45% of gas deliveries in the continental U.S. 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 U.S. South Central utilities account for 2.5% of the customers in the sample but almost 15% of those in the continental U.S.

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.

### 3.1.2 Ontario

The primary source of data used in our research on the index trends of Ontario gas utilities was Enbridge and Union. 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

[10] Large distributors that are not represented in the sample include Atmos, Columbia Gas of Ohio, Entex, Laclede Gas, Michigan Consolidated Gas, and Minnegasco.

Table 1

# SAMPLED U.S. GAS DISTRIBUTORS 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 | | |

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

itemized in these accounts. Partly for this reason, there are noteworthy inconsistencies in the data that Enbridge and Union made available for this study. For example, Union provided data on the labour expenses contained in net operation and maintenance ("O&M") expenses whereas Enbridge did not.

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 this 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. The weight for each group is based 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 4 input categories: capital, labour, gas used in facility operation, 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 of labour that contributed to net O&M expenses plus expenses for pensions and other benefits. *Net* rather than *gross* salaries and wages are required to avoid double counting costs of labour that are capitalized. Net salaries and wages are routinely reported by U.S. utilities and were provided by Union, as noted above. We prepared rough estimates of net salaries and wages from the data provided by Enbridge. 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 expenses attributable to net O&M were provided by Union and were estimated by PEG for Enbridge. Lacking a good basis for analogous estimates for U.S. 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. Enbridge and most U.S. gas utilities consume much less gas in system operation. The weight assigned to gas in their input price and quantity indexes was, accordingly zero.

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 demand-side management expenses of the companies.

The cost of **capital** was calculated using two approaches: geometric decay ("GD") and a novel 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 conventionally uses in its productivity research and that consultants for Union Gas used in its previous PBR proceeding. This approach features replacement (current dollar) valuation of utility plant and a constant rate of depreciation. The value of plant increases each year at the same rate as construction costs. However, cost 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 below.

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. This "service price" approach to capital costing has a solid basis in economics and is well established in the scholarly literature.[11] 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

[11] See, for example, Hall and Jorgenson (1967)

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 depreciation rates, and the cost of aquiring funds in capital markerts. The GD capital service price includes, additionally, a term for capital gains. The difference between the rate of return and capital gains is, effectively, the *real* rate of return on plant ownership. This return can be volatile because the cost of funds is itself quite variable and does not always rise (fall) when capital gains rise.

We computed indexes of the cost of funds for Enbridge and Union using the 65/35 weighting of debt and equity that is currently typical of their regulation. We used an Ontario cost of funds in the U.S. 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 U.S. data for the 1994-2004 period and find that 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 chose to focus on the 2000-2005 period for our Ontario productivity research. 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.

### 3.3.2 Econometric Cost Research

The index logic traced in Section 2.2 revealed that output quantity indexes featuring cost elasticity weights can have a number of uses in PCI design. Most notably, they can be used to calculate TFP indexes especially designed to measure cost efficiency trends and to establish an explicit PCI adjustment for declining average use. The elasticity-weighted output indexes used in this study for both U.S. and Canadian companies employed econometric estimates of the elasticity of cost with respect to output growth. These were drawn from an econometric model of the relationship between the total cost of gas utility (base rate) inputs and various business conditions. PEG developed this model expressly for this project. The econometric research also has uses in fashioning TFP targets for the calculation of productivity differentials, as we discuss further below.

We estimated the parameters of the cost model using the U.S. data for the full 1994-2004 sample period.[12][13] The addition of Ontario data to the sample would have involved major complications and prolonged the study but had little impact on results.[14] The GD approach to capital costing was used in the calculation of total cost. We were able to identify a number of statistically significant drivers of gas utility cost and the model had high explanatory power.

The choice of output quantity subindexes for the econometric cost research was limited by the available U.S. output data. Data are available for the number of customers served 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 employed three subindexes: 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.

All three of these quantity variables were found to be statistically significant cost drivers. Moreover, our research suggests that economies of scale are substantial in the gas utility business. At sample mean values of the business conditions, for instance, 1% growth in output raises the total cost of service by only 0.87%. Scale economies can, apparently, be realized from output growth even from large companies like Enbridge and Union.

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

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

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

[14] One notable source of complications would be the fashioning of consistent input prices.

- Cost was higher the higher was the price of capital services
- Cost was higher the higher was the cost of labour
- Cost was higher the higher was the share of cast iron in the total miles of gas mains.
- Cost was higher for utilities that served an urban core
- Cost was lower the greater was the number of electric customers served
- Cost trended downward by about 1% for reasons other than changes in the specified business conditions. Since the 1% is the estimated value of the cost model's trend variable parameter we call this the parametric trend estimate. It reflects in part 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.

### 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 were based, as noted above, on econometric elasticity estimates. There are three output subindexes: residential and commercial volumes, volumes of other services, and the number of customers served.

The residential and commercial volume data were weather normalized by PEG using heating degree days (HDDs) data provided by the companies and estimates of the impact of HDDs on volumes that we developed econometrically using U.S. volume and HDD data. Details of this work are discussed in Appendix Section A.1.2. We added to the weather normalized volumes estimates, provided by the companies, of their demand-side management ("DSM") savings. This treatment, combined with the exclusion of DSM expenses from cost, is undertaken in the hope that the PCIs will not compensate the utilities for their DSM activities. This task is left to other provisions of the IR plan.

The index weights in the output indexes used in TFP research are the same for all U.S. and Ontario utilities and reflect the estimated elasticities at sample mean values of the

U.S. business conditions. The resulting weights for residential and commercial volumes, other volumes, and the number of customers served were 15%, 11%, and 74% respectively.

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.* In these indexes, the shares of each billing determinant in *revenue* served as the weights. 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 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 U.S. utilities were, due to the data limitations discussed above, the same three used in the elasticity-weighted indexes: 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 U.S. data on the corresponding revenue shares, we employed instead the average of the revenue shares for Union and Enbridge[15]. These were: 52% for residential and commercial volumes, 21% for other volumes, and 27% 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. Our research thus suggests that utility finances will be very sensitive to any 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 may 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

[15] Data are not readily available for the *total* base rate revenue of U.S. gas utilities, much less the breakdown by billing determinant.

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 more accurate measures of output quantity trends. 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 with *fixed* revenue weights in PCI design.[16] 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.

### 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 for most utilities feature subindexes for three input categories: labour, M&S, and capital. The input index for Union features, as well, a quantity subindex for gas used in system operations.

Quantity indexes for capital are discussed in the section below. Each quantity subindex for labour was calculated as the ratio of salary and wage expenses to a labour price index. The labour price variables used in this study were constructed by PEG using data from multiple sources. For the Ontario utilities we used Ontario construction worker salaries and wages index. This was chosen in part in lieu of several available indexes of utility salaries and wages, all of which displayed implausibly slow growth over the 2000-2005 period.

For the U.S. 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

[16] Whether fixed or flexible weights are used in output index design, we use the indexes only to measure multi-year trends.

the national trends in this ECI using regional comprehensive ECIs. All of these ECIs are maintained by the BLS. These indexes were also constructed from BLS data. .

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 U.S. 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 U.S. TFP research. Recall that this research uses only the GD approach to capital costing. 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.[17] 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 0.87%.[18] Output quantity growth averaging 0.97% annually outpaced input quantity growth averaging 0.10%. Over the same period, the annual average growth rate in a federal government index of the trend in the multifactor productivity of the U.S. private business sector was a much more rapid 1.39%.

We also calculated the partial factor productivity (PFP) trend of the U.S. utilities in use of O&M inputs. Their PFP indexes grew at a 1.83% average annual rate over the full sample period for the sample as a whole. O&M inputs were thus a bright spot in the recent productivity experience of the sampled U.S. utilities.

Table 3 presents some details of the input quantity trends of the sampled U.S. utilities. It can be seen that the quantity trends of different kinds of inputs varied considerably. The quantity of capital grew at a 0.67% annual pace that was well above that of the summary input quantity index. Usage of O&M input thus grew at a considerably slower pace on balance. Use of labour declined materially whereas use of materials and

[17] Recall that we do not have base rate revenues for these companies.
[18] All growth trends noted in this report were computed logarithmically.

Table 2

## PRODUCTIVITY RESULTS: U.S. SAMPLE

| Year | Output Quantity Index | Input Quantity Index | TFP Index | O&M PFP Index | US Private Business Sector |
|---|---|---|---|---|---|
| 1994 | 1.000 | 1.000 | 1.000 | 1.000 | 93.7 |
| 1995 | 1.016 | 1.004 | 1.012 | 1.025 | 93.5 |
| 1996 | 1.029 | 1.005 | 1.024 | 1.048 | 95.1 |
| 1997 | 1.042 | 0.989 | 1.054 | 1.117 | 96.0 |
| 1998 | 1.045 | 0.984 | 1.062 | 1.154 | 97.5 |
| 1999 | 1.068 | 0.987 | 1.082 | 1.179 | 98.7 |
| 2000 | 1.087 | 0.992 | 1.095 | 1.179 | 100.0 |
| 2001 | 1.081 | 0.990 | 1.092 | 1.197 | 100.2 |
| 2002 | 1.094 | 0.993 | 1.102 | 1.214 | 101.8 |
| 2003 | 1.094 | 1.002 | 1.092 | 1.203 | 104.7 |
| 2004 | 1.102 | 1.010 | 1.091 | 1.200 | 107.7 |
| Average Annual Growth Rate **1994-2004** | **0.97%** | **0.10%** | **0.87%** | **1.83%** | **1.39%** |

**FIGURE 1: TFP RESULTS FOR U.S. GAS DISTRIBUTION SAMPLE**

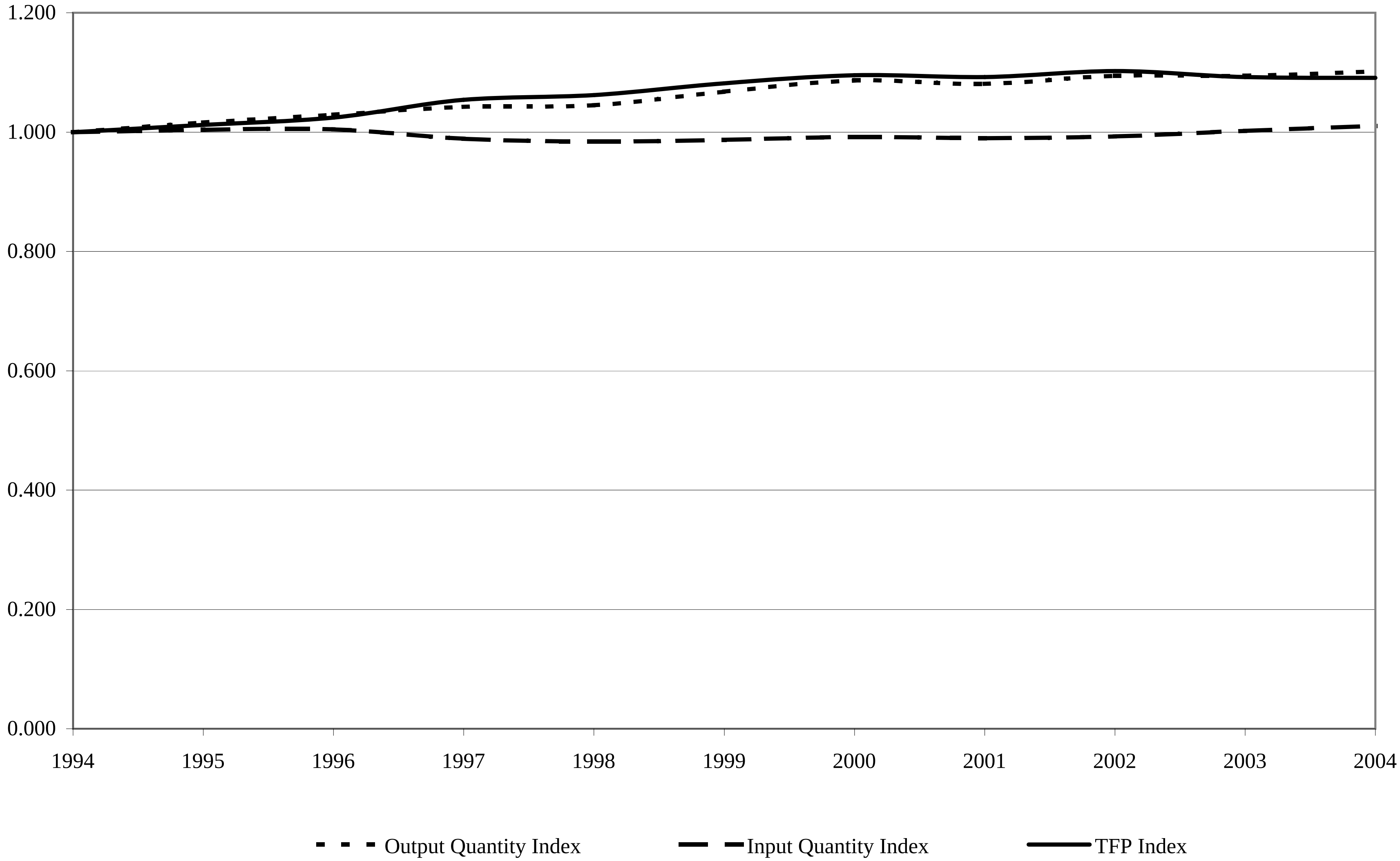

Table 3

## INPUT QUANTITY INDEXES: U.S. GAS DISTRIBUTION SAMPLE

| Year | Summary Input Quantity Index | Input Quantity Subindexes: Labor | Materials & Services | Capital (Geometric Decay) |
|---|---|---|---|---|
| 1994 | 1.000 | 1.000 | 1.000 | 1.000 |
| 1995 | 1.004 | 0.928 | 1.132 | 1.012 |
| 1996 | 1.005 | 0.914 | 1.131 | 1.022 |
| 1997 | 0.989 | 0.898 | 1.038 | 1.030 |
| 1998 | 0.984 | 0.855 | 1.058 | 1.037 |
| 1999 | 0.987 | 0.855 | 1.064 | 1.041 |
| 2000 | 0.992 | 0.790 | 1.198 | 1.046 |
| 2001 | 0.990 | 0.742 | 1.261 | 1.049 |
| 2002 | 0.993 | 0.780 | 1.192 | 1.054 |
| 2003 | 1.002 | 0.782 | 1.215 | 1.062 |
| 2004 | 1.010 | 0.740 | 1.314 | 1.069 |
| Average Annual Growth Rate **1994-2004** | **0.10%** | **-3.00%** | **2.73%** | **0.67%** |

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 U.S. utilities. It can be seen that the number of customers grew at a 1.63% average annual pace. The volume of residential and commercial deliveries grew at a much slower 0.61% average annual pace. The average use of gas by residential and commercial customers thus fell by about 1% annually.[19] We would expect this to result in a substantial difference between the growth trends of the revenue and elasticity weighted output quantity indexes. Output indexes with fixed revenue weights grew at a 0.11% average annual rate whereas output indexes with cost elasticity weights grew at a 0.97% average annual pace. The resultant output quantity trend differential averaged -0.86%.

Enbridge

Table 5 presents results of the TFP indexes for Enbridge and Union. Considering Enbridge first, we find using the GD approach to capital costing that its 1.03% average annual TFP growth from 2000 to 2005 was a little above the U.S. norm. The 2.57% average annual pace of output growth was more than double the U.S. norm. This reflects in large measure the brisk expansion of the Ottawa and Toronto metropolitan areas. Input quantity growth averaged 1.54% annually.

The PFP index for the company's O&M inputs, remarkably, fell at a 0.96% average annual pace. PFP fell substantially in 2003 and did not subsequently regain much of the lost ground. 2003 was the first year following the conclusion of the company's PBR plan for O&M inputs. Thus, there is no evidence that this plan produced lasting benefits for Enbridge customers.

Tables 6 and 7 present some details of the input and output quantity trends of Union and Enbridge. It can be seen that the input growth pattern was quite different from the U.S.

[19] 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 use since these sectors account for more than 95% of all customers.

Table 4

# OUTPUT QUANTITY INDEXES: U.S. GAS DISTRIBUTION SAMPLE

| | Summary Output | | Quantity Subindexes | | |
|---|---|---|---|---|---|
| **Year** | **Cost Elasticity Weights** | **Fixed Revenue Weights** | **Customer Numbers** | **Residential and Commercial Deliveries** | **Other Deliveries** |
| 1994 | 1.000 | 1.000 | 1.000 | 1.000 | 1.000 |
| 1995 | 1.016 | 1.015 | 1.019 | 1.027 | 0.982 |
| 1996 | 1.029 | 1.022 | 1.037 | 1.041 | 0.959 |
| 1997 | 1.042 | 1.030 | 1.056 | 1.060 | 0.930 |
| 1998 | 1.045 | 1.009 | 1.075 | 1.036 | 0.871 |
| 1999 | 1.068 | 1.033 | 1.095 | 1.054 | 0.913 |
| 2000 | 1.087 | 1.054 | 1.113 | 1.077 | 0.933 |
| 2001 | 1.081 | 1.009 | 1.137 | 1.036 | 0.814 |
| 2002 | 1.094 | 1.026 | 1.148 | 1.055 | 0.830 |
| 2003 | 1.094 | 1.016 | 1.163 | 1.081 | 0.737 |
| 2004 | 1.102 | 1.011 | 1.178 | 1.063 | 0.737 |
| Average Annual Growth Rate **1994-2004** | **0.97%** | **0.11%** | **1.63%** | **0.61%** | **-3.05%** |

Table 5

# PRODUCTIVITY RESULTS: ONTARIO

| Year | Output Quantity Index | | Input Quantity Index | | | | TFP Index | | | | O&M PFP Index | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cost Elasticity Weights | | GD Capital Cost | | COS Capital Cost | | GD Capital Cost | | COS Capital Cost | | | |
| | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** |
| 1999 | 1.000 | | 1.000 | | 1.000 | | 1.000 | | 1.000 | | 1.000 | |
| 2000 | 1.021 | 1.000 | 0.975 | 1.000 | 0.973 | 1.000 | 1.047 | 1.000 | 1.049 | 1.000 | 1.134 | 1.000 |
| 2001 | 1.021 | 1.027 | 0.975 | 1.025 | 0.976 | 1.025 | 1.047 | 1.001 | 1.046 | 1.002 | 1.119 | 0.966 |
| 2002 | 1.061 | 1.047 | 1.003 | 1.016 | 1.009 | 1.014 | 1.059 | 1.030 | 1.052 | 1.033 | 1.061 | 1.047 |
| 2003 | 1.075 | 1.093 | 1.000 | 1.062 | 0.998 | 1.065 | 1.075 | 1.029 | 1.077 | 1.026 | 1.121 | 0.944 |
| 2004 | 1.092 | 1.115 | 0.983 | 1.076 | 0.980 | 1.079 | 1.112 | 1.036 | 1.114 | 1.033 | 1.158 | 0.936 |
| 2005 | 1.116 | 1.137 | 0.966 | 1.080 | 0.966 | 1.088 | 1.156 | 1.053 | 1.156 | 1.045 | 1.203 | 0.953 |
| Average Annual Growth Rate | | | | | | | | | | | | |
| **1999-2005** | **1.84%** | NA | **-0.58%** | NA | **-0.58%** | NA | **2.42%** | NA | **2.41%** | NA | **3.08%** | NA |
| **2000-2005** | **1.78%** | **2.57%** | **-0.20%** | **1.54%** | **-0.15%** | **1.68%** | **1.98%** | **1.03%** | **1.93%** | **0.88%** | **1.17%** | **-0.96%** |

Table 6

# INPUT QUANTITY INDEXES: ONTARIO

| Year | Summary Input Quantity Indexes | | | | Input Quantity Subindexes | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | GD Capital Cost | | COS Capital Cost | | Labour | | Non-Labour | | Fuel | | Capital: GD Capital Cost | | Capital: COS Capital Cost | |
| | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union** | **Enbridge** |
| 1999 | 1.000 | | 1.000 | | 1.000 | | 1.000 | | 1.000 | NA | 1.000 | | 1.000 | |
| 2000 | 0.975 | 1.000 | 0.973 | 1.000 | 0.876 | 0.549 | 0.936 | 1.500 | 1.459 | NA | 1.003 | 1.000 | 1.003 | 1.000 |
| 2001 | 0.975 | 1.025 | 0.976 | 1.025 | 0.875 | 0.557 | 0.968 | 1.627 | 1.251 | NA | 1.002 | 1.011 | 1.006 | 1.010 |
| 2002 | 1.003 | 1.016 | 1.009 | 1.014 | 0.903 | 0.475 | 1.144 | 1.596 | 1.346 | NA | 1.003 | 1.020 | 1.008 | 1.020 |
| 2003 | 1.000 | 1.062 | 0.998 | 1.065 | 0.881 | 0.517 | 1.075 | 1.892 | 1.874 | NA | 1.002 | 1.031 | 0.996 | 1.026 |
| 2004 | 0.983 | 1.076 | 0.980 | 1.079 | 0.828 | 0.563 | 1.120 | 1.907 | 1.700 | NA | 0.989 | 1.037 | 0.983 | 1.032 |
| 2005 | 0.966 | 1.080 | 0.966 | 1.088 | 0.851 | 0.584 | 1.040 | 1.880 | 1.601 | NA | 0.975 | 1.043 | 0.973 | 1.044 |
| Average Annual Growth Rate | | | | | | | | | | | | | | |
| **1999-2005** | **-0.58%** | NA | **-0.58%** | NA | **-2.69%** | NA | **0.65%** | NA | **7.84%** | NA | **-0.43%** | NA | **-0.46%** | NA |
| **2000-2005** | **-0.20%** | **1.54%** | **-0.15%** | **1.68%** | **-0.58%** | **1.25%** | **2.11%** | **4.51%** | **1.86%** | NA | **-0.57%** | **0.84%** | **-0.60%** | **0.86%** |

Table 7

# OUTPUT QUANTITY INDEXES: ONTARIO

| Year | Summary Output Quantity Indexes | | | | Output Quantity Subindexes | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Cost Elasticity Weights | | Fixed Revenue Weights | | Customers | | Residential & Commercial Volume | | Other Volume | |
| | **Union** | **Enbridge** | **Union** | **Enbridge** | **Union**[1] | **Enbridge**[2] | **Union**[1] | **Enbridge**[2] | **Union**[1] | **Enbridge**[2] |
| 1999 | 1.000 | | 1.000 | | 1,103,636 | | 5,014 | | 29,613 | |
| 2000 | 1.021 | 1.000 | 1.024 | 1.000 | 1,123,523 | 1,464,738 | 5,164 | 7,179 | 30,525 | 4,597 |
| 2001 | 1.021 | 1.027 | 1.021 | 1.026 | 1,146,376 | 1,519,039 | 5,009 | 7,423 | 27,635 | 4,372 |
| 2002 | 1.061 | 1.047 | 1.059 | 1.022 | 1,171,277 | 1,566,710 | 5,241 | 7,250 | 32,023 | 4,392 |
| 2003 | 1.075 | 1.093 | 1.083 | 1.097 | 1,195,115 | 1,622,016 | 5,410 | 8,000 | 30,082 | 4,479 |
| 2004 | 1.092 | 1.115 | 1.083 | 1.097 | 1,224,276 | 1,676,380 | 5,210 | 7,897 | 31,169 | 4,389 |
| 2005 | 1.116 | 1.137 | 1.079 | 1.110 | 1,248,510 | 1,724,716 | 5,284 | 7,977 | 32,632 | 4,263 |
| Average Annual Growth Rate | | | | | | | | | | |
| **1999-2005** | **1.84%** | NA | **1.27%** | NA | **2.06%** | NA | **0.87%** | NA | **1.62%** | NA |
| **2000-2005** | **1.78%** | **2.57%** | **1.05%** | **2.08%** | **2.11%** | **3.27%** | **0.46%** | **2.11%** | **1.33%** | **-1.51%** |

[1]Union's output quantities are based on actuals that includes volumes saved due to DSM. Residential and commercial volume was weather normalized by PEG.

[2]Enbridge output quantities are based on actual data that includes volumes saved due to DSM. Residential and commercial volume was normalized by PEG

norm.  The 0.84% trend in the capital quantity using GD costing was well below the 1.36% trend in the summary index.

The TFP index for Enbridge that we calculated using COS capital costing had a 0.88% average annual growth rate over the 2000-2005 period—modestly below the pace we calculated using GD costing.  The slower growth reflects the greater sensitivity of the input quantity index to recent plant additions.

### Union

Table 5 reveals that the TFP growth of Union using GD costing averaged 1.98% growth per annum, more than double the U.S. norm and well above that of Enbridge.  The 1.78% average annual pace of output growth was well below that of Enbridge but still well above the North American norm.  Input growth *declined* by 0.20% on average, broadly similar to the U.S. trend.  Union's PFP index for O&M inputs averaged 1.17% annual growth, slower than the U.S. outcome but far above that for Enbridge.

Table 6 shows that the decline in input usage (using GD costing) was due chiefly to a 0.58% per annum decline in the use of capital during the sample period, which was quite different from the U.S. trend.  This goes a long ways towards explaining Union's remarkable TFP performance.  It is difficult to ascertain how much of this slow growth was due to capital spending restraint as opposed to a lack of need for capital investment.

The TFP index for Union that we calculated using COS capital costing exhibited 1.93% average annual growth over the 2000-2005 period.  This is very similar to the pace that we calculated using GD costing.

### 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 trends of other utilities.  This is often computed using the productivity trends of utilities in the same region as the subject utility.[20] 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 large Canadian utilities.
- Utilities in nearby areas of the United States (*e.g.,*Ohio and upstate New York) face different operating challenges than utilities in Ontario.

Research of two kinds was, accordingly, undertaken to assess the normal pace of TFP growth for companies facing the business conditions of Union and Enbridge using available U.S. data. Both approaches made use of our econometric cost research, which revealed that the realization of scale economies is an important potential source of differences in the TFP trends of gas utilities. One approach was to calculate the average TFP trends of peer groups consisting of companies with the same approximate opportunities to realize economies of scale as did Enbridge and Union. The opportunity for a gas distributor to realize scale economies depends chiefly on the pace of its output growth. We, accordingly, selected peer groups for each utility that had similar growth in the elasticity weighted output index.

Results of this analysis are reported in Tables 8 and 9. Each table contains output and productivity trends for all sampled U.S. companies. 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 1.34% TFP growth, a little above the company's actual 2000-2005 TFP trend. The Union peer group averaged 0.94% annual TFP growth, far below that Company's actual trend. A higher trend for the Enbridge peer group than for the Union peer group is consistent with our econometric findings concerning the potential for the realization of incremental scale economies.

Our second approach to establishing TFP targets for Enbridge and Union was to calculate the TFP growth that can be predicted from the econometric cost model given each company's opportunities to realize scale economies. In this exercise, we assigned each company the common parametric trend of 1.06% from the econometric model. We then

[20] 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.

Table 8

# CHOOSING TFP PEERS FOR ENBRIDGE

| | | | | |
|---|---|---|---|---|
| Arithmetic Sample Average fn | 0.79% | 1.17% | -1.40% | |
| **Peer Average** | **1.34%** | **2.60%** | **0.03%** | |
| Enbridge | 1.03% | 2.57% | | |

| | | Expected Scale Economies | | |
|---|---|---|---|---|
| Company | TFP | Company | vs. Enbridge | Peer |
| Southwest Gas | **2.6%** | 4.5% | 1.9% | |
| Cascade Natural Gas | **3.2%** | 3.9% | 1.4% | |
| Northwest Natural Gas | **1.8%** | 3.5% | 0.9% | 1 |
| Public Service of NC | **0.4%** | 3.3% | 0.7% | 1 |
| Washington Natural Gas | **0.6%** | 2.8% | 0.2% | 1 |
| Connecticut Energy | **2.4%** | 2.5% | -0.1% | 1 |
| New Jersey Natural | **1.5%** | 2.4% | -0.1% | 1 |
| Madison Gas & Electric | **0.8%** | 2.2% | -0.4% | 1 |
| Wisconsin Power & Light | **1.9%** | 2.1% | -0.4% | 1 |
| Mountain Fuel Supply | **1.2%** | 2.0% | -0.5% | 1 |
| San Diego Gas & Electric | **-0.5%** | 1.6% | -0.9% | |
| Louisville Gas & Electric | **0.3%** | 1.4% | -1.1% | |
| PG Energy | **1.3%** | 1.3% | -1.2% | |
| Atlanta Gas Light | **1.1%** | 1.3% | -1.3% | |
| Wisconsin Gas | **1.6%** | 1.2% | -1.3% | |
| Northern Illinois Gas | **0.9%** | 1.2% | -1.4% | |
| PECO | **0.5%** | 1.2% | -1.4% | |
| North Shore Gas | **1.7%** | 1.1% | -1.5% | |
| Consumers Power | **0.2%** | 1.0% | -1.5% | |
| Pacific Gas & Electric | **1.8%** | 0.8% | -1.8% | |
| East Ohio Gas | **1.9%** | 0.7% | -1.9% | |
| Central Hudson Gas & Electric | **1.0%** | 0.6% | -1.9% | |
| Nstar Gas | **1.9%** | 0.6% | -1.9% | |
| Washington Gas Light | **-0.1%** | 0.6% | -2.0% | |
| Southern California Gas | **1.1%** | 0.6% | -2.0% | |
| Baltimore Gas and Electric | **0.3%** | 0.6% | -2.0% | |
| Rochester Gas and Electric | **0.8%** | 0.5% | -2.0% | |
| Public Service Electric & Gas | **-0.9%** | 0.3% | -2.2% | |
| Alabama Gas | **-1.9%** | 0.3% | -2.3% | |
| Niagara Mohawk | **0.9%** | 0.2% | -2.4% | |
| Illinois Power | **2.2%** | 0.2% | -2.4% | |
| Consolidated Edison | **0.5%** | 0.1% | -2.5% | |
| People's Natural Gas | **0.3%** | 0.0% | -2.5% | |
| Orange and Rockland | **-3.0%** | -1.0% | -3.6% | |
| Peoples Gas Light & Coke | **-0.4%** | -1.4% | -4.0% | |
| Connecticut Natural Gas | **-1.6%** | -2.1% | -4.7% | |

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

Table 9

# CHOOSING TFP PEERS FOR UNION

| | | | | |
|---|---|---|---|---|
| Arithmetic Sample Average fn | 0.79% | 1.17% | -0.61% | |
| **Peer Average** | **0.94%** | **1.81%** | **0.03%** | |
| Union | 1.98% | 1.78% | | |

| | | Expected Scale Economies | | |
|---|---|---|---|---|
| Company | **TFP** | Company | vs. Union | Peer |
| Southwest Gas | **2.6%** | 4.5% | 2.7% | |
| Cascade Natural Gas | **3.2%** | 3.9% | 2.2% | |
| Northwest Natural Gas | **1.8%** | 3.5% | 1.7% | |
| Public Service of NC | **0.4%** | 3.3% | 1.5% | |
| Washington Natural Gas | **0.6%** | 2.8% | 1.0% | |
| Connecticut Energy | **2.4%** | 2.5% | 0.7% | |
| New Jersey Natural | **1.5%** | 2.4% | 0.6% | 1 |
| Madison Gas & Electric | **0.8%** | 2.2% | 0.4% | 1 |
| Wisconsin Power & Light | **1.9%** | 2.1% | 0.4% | 1 |
| Mountain Fuel Supply | **1.2%** | 2.0% | 0.3% | 1 |
| San Diego Gas & Electric | **-0.5%** | 1.6% | -0.2% | 1 |
| Louisville Gas & Electric | **0.3%** | 1.4% | -0.4% | 1 |
| PG Energy | **1.3%** | 1.3% | -0.5% | 1 |
| Atlanta Gas Light | **1.1%** | 1.3% | -0.5% | 1 |
| Wisconsin Gas | **1.6%** | 1.2% | -0.6% | |
| Northern Illinois Gas | **0.9%** | 1.2% | -0.6% | |
| PECO | **0.5%** | 1.2% | -0.6% | |
| North Shore Gas | **1.7%** | 1.1% | -0.7% | |
| Consumers Power | **0.2%** | 1.0% | -0.7% | |
| Pacific Gas & Electric | **1.8%** | 0.8% | -1.0% | |
| East Ohio Gas | **1.9%** | 0.7% | -1.1% | |
| Central Hudson Gas & Electric | **1.0%** | 0.6% | -1.1% | |
| Nstar Gas | **1.9%** | 0.6% | -1.2% | |
| Washington Gas Light | **-0.1%** | 0.6% | -1.2% | |
| Southern California Gas | **1.1%** | 0.6% | -1.2% | |
| Baltimore Gas and Electric | **0.3%** | 0.6% | -1.2% | |
| Rochester Gas and Electric | **0.8%** | 0.5% | -1.3% | |
| Public Service Electric & Gas | **-0.9%** | 0.3% | -1.4% | |
| Alabama Gas | **-1.9%** | 0.3% | -1.5% | |
| Niagara Mohawk | **0.9%** | 0.2% | -1.6% | |
| Illinois Power | **2.2%** | 0.2% | -1.6% | |
| Consolidated Edison | **0.5%** | 0.1% | -1.7% | |
| People's Natural Gas | **0.3%** | 0.0% | -1.8% | |
| Orange and Rockland | **-3.0%** | -1.0% | -2.8% | |
| Peoples Gas Light & Coke | **-0.4%** | -1.4% | -3.2% | |
| Connecticut Natural Gas | **-1.6%** | -2.1% | -3.9% | |

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

added this to each company's estimated potential for scale economy realization resulting from their historical pace of output growth. This depends on the availability of incremental scale economies from growth in output and on the trend in the elasticity–weighted output index from 2000 to 2005. Results of this analysis are reported in Table 10. It can be seen that the TFP trend targets calculated in this way for Enbridge and Union are 1.37% and 1.29% respectively. Both numbers are close to the corresponding peer group trends.

The econometric model also provides us with an estimate of the effect of cast iron replacement on TFP growth. This could potentially be added to the TFP trend target for Enbridge if supported by the data. As discussed in Section 3.3.2 we found that cast iron mains raise total cost. This implies that a reduction in cast iron would *accelerate* TFP growth. However, this is a long run result and the short term effect on TFP growth may be different since the O&M cost savings may be offset initially by the cost impact of the underappreciated new pipe. As an extra check, we regressed the growth in the TFP of our sampled U.S. utilities on the change in their cast iron reliance using data for the sample period. The hypothesis that a change in cast iron reliance has no effect on TFP growth could not be rejected at a high level of confidence. Our research does not then prompt us to adjust the econometric TFP target for Enbridge to reflect its plan for cast iron reduction. Different results might obtain using the COS approach to capital costing due to the greater sensitivity to the pace of recent investment.

We conclude from our research using GD capital costing that the appropriate productivity growth target for Enbridge should exceed the company's historical trend. Less clear is the margin by which the target should exceed the trend. As a straw man we propose to use the 1.37% productivity growth predicted by the econometric cost research.

As for Union, it is difficult to ascertain to what degree its superior TFP growth between 2000 and 2005 is due to superior management and to what degree it is due to its special circumstances, which include its operation of a sizable transmission and storage system. We conclude that Union's productivity growth target should be less than the pace it achieved from 2000 to 2005 but may reasonably be set above the peer group trend. The sum of Union's productivity target and any stretch factor that is added to X should not be allowed to exceed the company's recent TFP trend. As a straw man, we propose that

Table 10

# TFP GROWTH PROJECTIONS FROM ECONOMETRIC RESEARCH

| | Enbridge | Union | US Mean |
|---|---|---|---|
| **Sample Years** | 2000-2005 | 2000-2005 | 1994-2004 |
| **Technological Change [A]** | **1.06%** | **1.06%** | **1.06%** |
| **Returns to Scale [B]** | **0.31%** | **0.23%** | **0.13%** |
| Sum of Output Elasticities | 0.87 | 0.87 | 0.87 |
| Output Growth (elasticity weighted) | 2.42% | 1.79% | 0.98% |
| Output Parameters | | | |
| Customers | *0.64* | *0.64* | *0.64* |
| RC Deliveries | *0.13* | *0.13* | *0.13* |
| Other Deliveries | *0.09* | *0.09* | *0.09* |
| Weight - Customers | 74.04% | 74.04% | 74.04% |
| Weight - RC Deliveries | 15.10% | 15.10% | 15.10% |
| Weight - Other Deliveries | 10.86% | 10.86% | 10.86% |
| Customer Growth | 3.13% | 2.11% | 1.64% |
| RC Delivery Growth | 1.32% | 0.55% | 0.61% |
| Other Delivery Growth | -0.92% | 1.31% | -3.01% |
| **TFP Projection [A + B]** | **1.37%** | **1.29%** | **1.18%** |

Union's TFP growth target be set at 1.63, halfway between the econometric projction and its own recent trend.

The productivity targets for COS capital costing are more problematic to calculate since we did not calculate the TFP trends of the U.S. utilities using COS costing. As a straw man proposal, we set the targets by means of basis point adjustments to the companies' TFP targets based on GD costing. These adjustments are the difference between each company's TFP trends using COS and GD costing. The straw man target for Enbridge is thus 1.22% (1.37+0.88-1.03). The target for Union is 1.58% (1.63+1.93-1.98).

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 1992-2003 to be a sensible input price comparison period when GD capital costing is used. The MFP trend of the Canadian economy was 1.37% during this period. The straw man productivity differential for Enbridge using GD capital costing is thus -0.00% (1.37 – 1.37). The straw man productivity differential for Union is thus +0.26% (1.63 – 1.37).

As for the TFP results using COS capital costing, we found 1998-2005 to be a sensible input price comparison period. The MFP trend of the Canadian economy was 1.21% during this period. The straw man productivity differential for Enbridge using COS capital costing is thus -0.01% (1.22 – 1.21). The straw man productivity differential for Union is thus +0.37% (1.58-1.21).

## 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, their actual volumes per customer for the period 2000-2005 by service class as well as weather normalized treatments calculated by PEG and the companies. Company figures for Enbridge were calculated using weather normalized data that they provided to PEG. These are compared to numbers provided by the company in a presentation at a fall stakeholders conference, and to the forecasts approved in rate cases on which the company's rates are based. Company figures for Union were calculated using weather normalized volumes provided to PEG by the company.

Table 11a

# Volume Per Customer Trends by Enbridge Rate Class

## Rate 1 (Residential)

| Year | Volumes: Actual [A] | Volumes: Forecasted [B] | Volumes: Normalized PEG [C] | Volumes: Normalized Enbridge [D] | Customers: Actual [E] | Customers: Forecasted [F] | Volume Per Customer: Actual [G]=1000*[A]/[E] | Volume Per Customer: Forecasted [H]=[B]/[F] | Volume Per Customer: Normalized PEG [I]=1000*[C]/[E] | Volume Per Customer: Normalized Enbridge [J]=1000*[D]/[E] | Enbridge Stakeholder Presentation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2000 | 4,008 | 4,266,360 | 4,088 | 4,283 | 1,325,938 | 1,328,659 | 3.023 | 3.211 | 3.083 | 3.230 | 3,043 |
| 2001 | 4,228 | 4,163,327 | 4,196 | 4,147 | 1,377,459 | 1,373,517 | 3.070 | 3.031 | 3.046 | 3.010 | 2,940 |
| 2002 | 4,002 | 4,203,965 | 4,165 | 4,233 | 1,423,525 | 1,418,180 | 2.812 | 2.964 | 2.926 | 2.973 | 2,929 |
| 2003 | 4,735 | 4,241,724 | 4,568 | 4,242 | 1,476,603 | 1,468,966 | 3.207 | 2.888 | 3.094 | 2.873 | 2,900 |
| 2004 | 4,596 | 4,241,724 | 4,557 | 4,342 | 1,529,297 | 1,468,966 | 3.006 | 2.888 | 2.980 | 2.839 | 2,850 |
| 2005 | 4,620 | 4,626,802 | 4,604 | 4,548 | 1,575,322 | 1,568,544 | 2.932 | 2.950 | 2.923 | 2.887 | 2,779 |
| **2000-2005** | **2.84%** | **1.62%** | **2.38%** | **1.20%** | **3.45%** | **3.32%** | **-0.61%** | **-1.70%** | **-1.07%** | **-2.25%** | **-1.82%** |

## Rate 6 (General Service)

| Year | Volumes: Actual [A] | Volumes: Forecasted [B] | Volumes: Normalized PEG [C] | Volumes: Normalized Enbridge [D] | Customers: Actual [E] | Customers: Forecasted [F] | Volume Per Customer: Actual [G]=1000*[A]/[E] | Volume Per Customer: Forecasted [H]=[B]/[F] | Volume Per Customer: Normalized PEG [I]=1000*[C]/[E] | Volume Per Customer: Normalized Enbridge [J]=1000*[D]/[E] | Enbridge Stakeholder Presentation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2000 | 2,999 | 3,175,841 | 3,050 | 3,219 | 136,025 | 138,575 | 22.050 | 22.918 | 22.422 | 23.663 | 22,138 |
| 2001 | 3,200 | 3,148,327 | 3,179 | 3,139 | 138,779 | 138,443 | 23.058 | 22.741 | 22.907 | 22.619 | 21,930 |
| 2002 | 2,932 | 3,200,782 | 3,032 | 3,110 | 140,351 | 144,102 | 20.888 | 22.212 | 21.603 | 22.156 | 21,785 |
| 2003 | 3,485 | 3,119,887 | 3,381 | 3,095 | 142,656 | 143,293 | 24.430 | 21.773 | 23.700 | 21.694 | 21,816 |
| 2004 | 3,314 | 3,119,887 | 3,290 | 3,110 | 144,331 | 143,293 | 22.959 | 21.773 | 22.795 | 21.548 | 21,527 |
| 2005 | 3,327 | 3,324,324 | 3,317 | 3,271 | 146,672 | 147,475 | 22.681 | 22.542 | 22.615 | 22.301 | 21,131 |
| **2000-2005** | **2.07%** | **0.91%** | **1.68%** | **0.32%** | **1.51%** | **1.25%** | **0.56%** | **-0.33%** | **0.17%** | **-1.19%** | **-0.93%** |

## Rate 100 (Large Volume Firm)

| Year | Volumes: Actual [A] | Volumes: Forecasted [B] | Volumes: Normalized PEG [C] | Volumes: Normalized Enbridge [D] | Customers: Actual [E] | Customers: Forecasted [F] | Volume Per Customer: Actual [G]=1000*[A]/[E] | Volume Per Customer: Forecasted [H]=[B]/[F] | Volume Per Customer: Normalized PEG [I]=1000*[C]/[E] | Volume Per Customer: Normalized Enbridge [J]=1000*[D]/[E] | Enbridge Stakeholder Presentation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2000 | 1,395 | 1,480,125 | 1,412 | NA | 2,019 | 1,993 | 691.035 | 742.662 | 699.356 | NA | NA |
| 2001 | 1,405 | 1,425,997 | 1,398 | NA | 2,043 | 1,911 | 687.714 | 746.205 | 684.288 | NA | NA |
| 2002 | 1,358 | 1,393,737 | 1,391 | NA | 2,087 | 1,956 | 650.455 | 712.544 | 666.507 | NA | NA |
| 2003 | 1,466 | 1,394,623 | 1,434 | NA | 2,029 | 2,007 | 722.425 | 694.822 | 706.752 | NA | NA |
| 2004 | 1,433 | 1,394,623 | 1,425 | NA | 2,069 | 2,007 | 692.412 | 694.822 | 688.739 | NA | NA |
| 2005 | 1,421 | 1,401,603 | 1,418 | NA | 2,065 | 1,985 | 687.893 | 706.127 | 686.683 | NA | NA |
| **2000-2005** | **0.36%** | **-1.09%** | **0.08%** | **NA** | **0.45%** | **-0.08%** | **-0.09%** | **-1.01%** | **-0.37%** | **NA** | **NA** |

Table 11b

# Volume Per Customer Trends by Union Overall Rate Class

### Rate M2: (General Service South, includes residential)

| Year | Volumes | | | Customers | Volume Per Customer[1] | | | |
|---|---|---|---|---|---|---|---|---|
| | Actual | Weather Normalized | | Actual | Actual | Weather Normalized | | Union Stakeholder Presentation |
| | | PEG | Union | | | PEG | Union | |
| | [A] | [B] | [C] | [D] | [E]=1000*[A]/[D] | [F]=1000*[B]/[D] | [G]=1000*[C]/[D] | |
| 1999 | 3,748 | 3,784 | | 836,601 | | | | NA |
| 2000 | 3,898 | 3,843 | 3,897 | 848,719 | 4.593 | 4.528 | 4.592 | NA |
| 2001 | 3,668 | 3,773 | 3,902 | 869,021 | 4.221 | 4.342 | 4.490 | NA |
| 2002 | 3,911 | 3,951 | 4,054 | 890,233 | 4.393 | 4.438 | 4.554 | NA |
| 2003 | 4,164 | 4,074 | 3,948 | 911,282 | 4.569 | 4.471 | 4.332 | NA |
| 2004 | 3,945 | 3,925 | 3,976 | 935,557 | 4.217 | 4.195 | 4.250 | NA |
| 2005 | 4,028 | 4,010 | 4,015 | 956,004 | 4.213 | 4.195 | 4.200 | NA |
| **2000-2005** | **0.66%** | **0.85%** | **0.60%** | **2.38%** | **-1.72%** | **-1.53%** | **-1.78%** | **NA** |

### Rate 01: (General Service North, includes residential)

| Year | Volumes | | | Customers | Volume Per Customer[1] | | | |
|---|---|---|---|---|---|---|---|---|
| | Actual | Weather Normalized | | Actual | Actual | Weather Normalized | | Union Stakeholder Presentation |
| | | PEG | Union | | | PEG | Union | |
| | [A] | [B] | [C] | [D] | [E]=1000*[A]/[D] | [F]=1000*[B]/[D] | [G]=1000*[C]/[D] | |
| 1999 | 844 | 856 | | 263,686 | | | | NA |
| 2000 | 945 | 930 | 959 | 271,537 | 3.480 | 3.425 | 3.532 | NA |
| 2001 | 855 | 879 | 932 | 274,087 | 3.119 | 3.207 | 3.400 | NA |
| 2002 | 912 | 908 | 939 | 277,588 | 3.285 | 3.271 | 3.383 | NA |
| 2003 | 957 | 945 | 921 | 280,373 | 3.413 | 3.371 | 3.285 | NA |
| 2004 | 919 | 905 | 926 | 285,201 | 3.222 | 3.173 | 3.247 | NA |
| 2005 | 886 | 894 | 921 | 288,801 | 3.068 | 3.096 | 3.189 | NA |
| **2000-2005** | **-1.29%** | **-0.79%** | **-0.81%** | **1.57%** | **-2.52%** | **-2.02%** | **-2.04%** | **NA** |

### Rate 10: (General Service North)

| Year | Volumes | | | Customers | Volume Per Customer[1] | | | |
|---|---|---|---|---|---|---|---|---|
| | Actual | Weather Normalized | | Actual | Actual | Weather Normalized | | Union Stakeholder Presentation |
| | | PEG | Union | | | PEG | Union | |
| | [A] | [B] | [C] | [D] | [E]=1000*[A]/[D] | [F]=1000*[B]/[D] | [G]=1000*[C]/[D] | |
| 1999 | 355 | 359 | | | | | | NA |
| 2000 | 386 | 382 | 396 | 2,631 | 146.712 | 145.192 | 150.513 | NA |
| 2001 | 348 | 355 | 367 | 2,632 | 132.219 | 134.878 | 139.438 | NA |
| 2002 | 382 | 381 | 387 | 2,841 | 134.460 | 134.108 | 136.220 | NA |
| 2003 | 394 | 390 | 380 | 2,842 | 138.635 | 137.227 | 133.709 | NA |
| 2004 | 384 | 380 | 384 | 2,914 | 131.778 | 130.405 | 131.778 | NA |
| 2005 | 385 | 388 | 397 | 3,114 | 123.635 | 124.599 | 127.489 | NA |
| **2000-2005** | **-0.05%** | **0.31%** | **0.05%** | **3.37%** | **-3.42%** | **-3.06%** | **-3.32%** | **NA** |

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

Inspecting the tables, it is evident that there were material declines in actual and weather normalized average use for all of the service classes of both companies that included residential customers. Weather normalization tended to increase the average use declines of Enbridge and to reduce the average use declines of Union. This result is explained by the fact that the former company reported volumes on a fiscal year data whereas the latter company reported on a calendar year basis. The HDDs for the heating seasons of the two companies can therefore differ considerably.

It is also interesting to not that whereas the weather normalized trends computed by PEG and Union are similar, the trends computed by PEG and Enbridge are quite different. The figures calculated by PEG suggest average use declines for Enbridge that are less severe than those calculated by the company. This discrepancy merits further investigation in the coming weeks.

Note finally, that Union has a major service class with commercial customers (Rate 10) that has been found to display a pronounced average use decline using both the company's and PEG's normalization method. Enbridge does not.

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 were -0.49% (2.08-2.57) and -0.73% (1.05-1.78) respectively. The AU for Union is thus modestly more negative than that for Enbridge despite Union's smaller reliance on residential and commercial services for base rate revenue.

## 3.5 Input Price Research

The trend in an input price index was noted in Section 2.1 to be a cost share weighted average of the growth in subindexes that measure inflation in the prices of certain input groups. 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 different from those in the input quantity indexes because all taxes were removed from the cost of capital. We assume, effectively, that tax rates rise at the average rate of the prices of all inputs.

U.S. Research

In the U.S. research, the price subindex for labour was constructed using the ECI for the *total* labour cost of the electric, gas, and sanitary sector of the U.S. economy. This includes the cost of pensions and benefits. An adjustment was made for the difference between regional and national labour cost trends. The price subindex for other O&M inputs was the chain-weighted gross domestic product price index. The price subindex for distribution plant was a capital service price index. This did not contain a term for taxes, as just noted.

Ontario Research

In the Ontario input price research, 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 construction cost index was constructed using a Stats Canada index of trends in *power* distribution construction costs. No analogous index of trends in gas utility construction costs appears to be available. We adjusted the growth rate in the power distribution construction cost index for the difference between the trends in the corresponding Handy Whitman indexes of U.S. gas utility and power distribution utility construction costs. The rate of return was a 65/35 average of Stats Canada indexes for long term corporate bond yields and the return on equity of Canada utilities.

### 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. The input price index for the industry is commonly computed using utility cost share data and input price subindexes drawn from external sources such as Stats Canada. It is not necessary to use the same sample periods for the IPD and PD calculations.

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 apparently rose at a brisk pace in 2004, 2005, and 2006 due, chiefly, to a runup in world market prices of steel and polyvinyl chloride, the material used to make most plastic natural gas piping. The impact of these developments on gas utility cost was, to some degree, offset by a downward trend in yields on long term bonds.

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 can fluctuate remarkably if the cost of funds does not rise when construction cost accelerates. 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.

Details of the calculation of the capital service price index using GD costing are reported in Table 12 and Figures 2 & 3. It can be seen that the following years of slow growth, the construction cost index grew by about 10% in 2004 and 11% in 2005 after years of slow growth. The weighted average cost of funds, meanwhile, was little changed in 2004 and fell 12% in 2005. The end result was that the (unsmoothed) real rate of return fell sharply in 2004 and 2005 to values in the negative range. The *smoothed* rate of return also declined substantially and entered negative territory in 2005.

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. Note in particular that natural gas is an itemized input category for Union but not for Enbridge. That is because Union operates a number of compressors in its storage and transmission system.

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 index for Enbridge fell by about 25% and 38% in 2004 and 2005. 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.

Table 12

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

| Year | Rate of Return | | | | | | Construction Cost Index | | | Real Rate of Return | | | | Depreciation Rate[7] | Capital Service Price Indexes | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Corporate Long Term Bond Yield | | Return on Equity[3] | | Weighted Average Cost of Capital | | | | Capital Gain (Smoothed) | 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] = (.65*A+.35*B) | (%) | [D] | $[E]=\frac{(D_t-D_{(t-1)})}{D_{(t-1)}}$ | [F]=3 Year Moving Average of [E] | [G]=C-E | (%) | [H]=3 Year Moving Average of [G] | (%) | [I] | $[J]=G*D_{(t-1)}+I*D_t$ | (%) | $[K]=D_{(t-1)}*H+I*D_t$ | (%) |
| 1988 | 10.9% | | 12.7% | 6.4% | 9.4% | | 9.5 | 6.7% | 3.6% | 2.7% | | | | 3.7% | 0.58 | | | |
| 1989 | 10.8% | -1.1 | 11.5% | 5.5% | 8.9% | -4.6 | 9.8 | 3.8% | 3.2% | 5.2% | 64.7 | | | 3.7% | 0.85 | 38.8 | | |
| 1990 | 11.9% | 9.7 | 7.6% | 4.2% | 9.2% | 2.9 | 10.1 | 2.5% | 4.3% | 6.7% | 26.6 | 4.9% | | 3.7% | 1.04 | 19.4 | 0.85 | |
| 1991 | 10.8% | -9.7 | 3.9% | 3.5% | 8.3% | -10.9 | 10.0 | -0.3% | 2.0% | 8.5% | 23.6 | 6.8% | 33.6 | 3.7% | 1.23 | 17.3 | 1.06 | 21.7 |
| 1992 | 9.9% | -8.8 | 1.7% | 6.0% | 8.5% | 3.1 | 10.3 | 3.1% | 1.8% | 5.4% | -45.6 | 6.9% | 1.2 | 3.7% | 0.93 | -28.4 | 1.08 | 1.7 |
| 1993 | 8.8% | -11.2 | 3.8% | 6.2% | 7.9% | -7.0 | 10.7 | 3.1% | 2.0% | 4.8% | -12.0 | 6.2% | -9.9 | 3.7% | 0.89 | -3.8 | 1.04 | -3.2 |
| 1994 | 9.4% | 6.5 | 6.7% | 5.9% | 8.2% | 3.3 | 11.6 | 8.4% | 4.9% | -0.2% | NA | 3.3% | -63.1 | 3.7% | 0.40 | -79.3 | 0.78 | -28.5 |
| 1995 | 9.0% | -4.6 | 9.8% | 5.5% | 7.8% | -5.1 | 12.3 | 6.7% | 6.1% | 1.1% | NA | 1.9% | -56.0 | 3.7% | 0.59 | 37.8 | 0.68 | -14.6 |
| 1996 | 8.1% | -10.6 | 10.3% | 6.2% | 7.4% | -4.7 | 12.3 | 0.0% | 5.0% | 7.4% | 187.6 | 2.8% | 37.9 | 3.7% | 1.37 | 84.6 | 0.80 | 16.6 |
| 1997 | 7.0% | -15.4 | 10.9% | 5.4% | 6.4% | -14.7 | 12.7 | 3.0% | 3.2% | 3.4% | -77.4 | 4.0% | 36.5 | 3.7% | 0.89 | -43.0 | 0.96 | 18.7 |
| 1998 | 6.2% | -11.1 | 8.8% | 5.0% | 5.8% | -10.2 | 13.1 | 3.4% | 2.1% | 2.4% | -34.0 | 4.4% | 10.3 | 3.7% | 0.80 | -11.5 | 1.05 | 8.5 |
| 1999 | 6.6% | 6.5 | 9.9% | 8.9% | 7.4% | 24.6 | 13.8 | 5.0% | 3.8% | 2.5% | 0.9 | 2.8% | -46.9 | 3.7% | 0.83 | 4.6 | 0.88 | -18.2 |
| 2000 | 7.1% | 7.1 | 10.9% | 7.3% | 7.2% | -3.2 | 14.4 | 4.1% | 4.1% | 3.1% | 24.0 | 2.7% | -3.7 | 3.7% | 0.96 | 14.4 | 0.90 | 2.8 |
| 2001 | 7.1% | -0.5 | 7.4% | 10.2% | 8.2% | 12.9 | 14.3 | -0.7% | 2.8% | 8.8% | 104.2 | 4.8% | 58.8 | 3.7% | 1.80 | 62.5 | 1.22 | 30.3 |
| 2002 | 7.0% | -1.6 | 5.7% | 6.4% | 6.8% | -18.8 | 14.2 | -0.3% | 1.0% | 7.1% | -22.5 | 6.3% | 27.7 | 3.7% | 1.54 | -15.9 | 1.43 | 16.1 |
| 2003 | 6.5% | -7.1 | 9.6% | 7.4% | 6.8% | 0.5 | 14.4 | 1.3% | 0.1% | 5.6% | -23.9 | 7.2% | 12.1 | 3.7% | 1.33 | -14.7 | 1.55 | 8.0 |
| 2004 | 6.1% | -7.0 | 11.4% | 8.4% | 6.9% | 0.7 | 15.8 | 9.7% | 3.5% | -2.8% | NA | 3.3% | -78.1 | 3.7% | 0.18 | -197.8 | 1.06 | -38.3 |
| 2005 | 5.4% | -12.3 | 11.4% | 7.4% | 6.1% | -12.2 | 17.6 | 11.4% | 7.4% | -5.3% | NA | -0.9% | NA | 3.7% | -0.19 | NA | 0.52 | -71.4 |
| 2006 | 5.4% | 0.6 | 11.2% | 5.7% | 5.5% | -9.9 | *17.6* [7] | 0.1% | 7.1% | 5.4% | NA | -0.9% | NA | 3.7% | 1.62 | NA | 0.51 | -1.9 |
| **Average Annual Growth Rate (%)** | | | | | | | | | | | | | | | | | | |
| 1991-2005 | | -5.00 | 7.76 | 5.28 | | -2.19 | | 4.01 | 3.43 | | NA | | NA | 0.00 | | NA | | -5.09 |
| **1993-2002** | | **-2.64** | **4.46** | **0.31** | | **-1.74** | | **3.20** | **3.68** | | **4.30** | | **0.17** | **0.00** | | **6.03** | | **3.54** |
| **1994-2004** | | **-4.43** | **5.32** | **3.46** | | **-1.78** | | **3.11** | **3.19** | | **NA** | | **-0.13** | **0.00** | | **-7.89** | | **3.00** |
| 2000-2005 | | -5.69 | 0.90 | 0.21 | | -3.39 | | 4.06 | 2.98 | | NA | | NA | 0.00 | | NA | | -11.06 |

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

[1]Source: Statistics Canada, average bond yields on Canadian corporate bonds.

[2]All growth rates are logarithmic except the Construction Cost Index.

[3]Source: Statistics Canada, 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]Source: Statistics Canada, Electric Distribution Utility Construction Cost Index. This was adjusted for differences in the growth rates of the Handy Whitman indexes of gas and electric utility construction costs.

[6]This number is computed using the Electric Utility Construction Cost Index, but was only adjusted for the differences in the growth rates of the Handy Whitman indexes for January 2006.

[7]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**

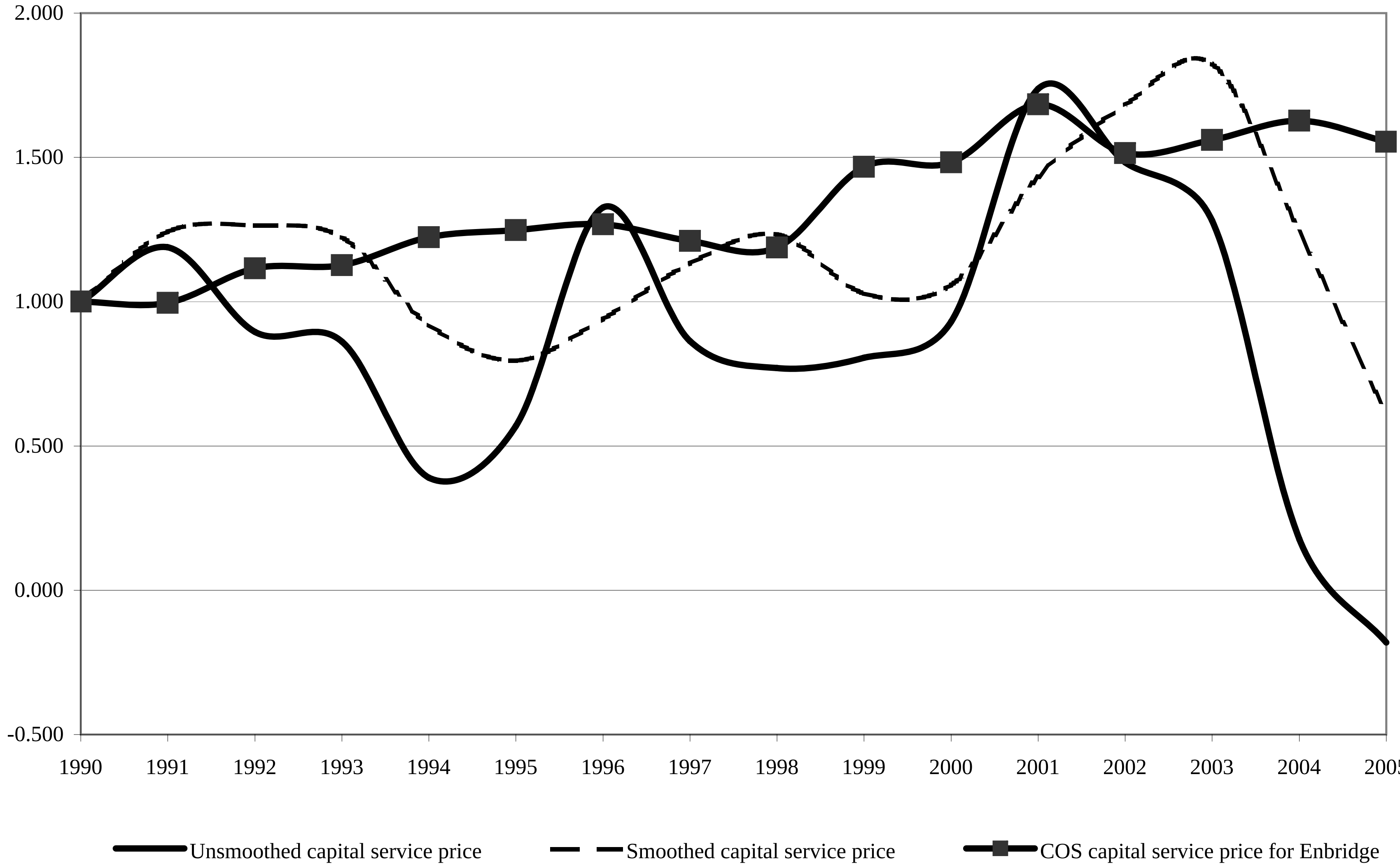

Table 13a

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

| | Capital (Unsmoothed) | | | Capital (Real Rate Smoothed) | | | Labour | | | Cost of Natural Gas | | | Materials and Services | | | IPI - Enbridge Unsmoothed | | IPI - Enbridge Smoothed | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Index[1] | Growth Rate (%) | Weight° (%) | Index[1] | Growth Rate (%) | Weight° (%) | Index[2] | Growth Rate (%) | Weight° (%) | Index[3] | Growth Rate (%) | Weight° (%) | Index[4] | Growth Rate (%) | Weight° (%) | Level | Growth Rate (%) | Level | Growth Rate (%) |
| 1988 | 0.58 | | | | | | 80.1 | | | 100.2 | | | 82.2 | | | 1.00 | | | |
| 1989 | 0.85 | 39 | 70.8 | | | 70.8 | 85.1 | 6.1 | 9.4 | 95.6 | -4.7 | 0.0 | 86.4 | 5.0 | 19.9 | 1.34 | 29.0 | | |
| 1990 | 1.04 | 19 | 70.8 | 0.85 | | 70.8 | 90.3 | 5.9 | 9.4 | 96.5 | 0.9 | 0.0 | 89.2 | 3.2 | 19.9 | 1.55 | 14.9 | | |
| 1991 | 1.23 | 17 | 70.8 | 1.06 | 22 | 70.8 | 96.5 | 6.6 | 9.4 | 98.2 | 1.7 | 0.0 | 93.0 | 4.2 | 19.9 | 1.78 | 13.7 | 1.00 | |
| 1992 | 0.93 | -28 | 70.8 | 1.08 | 2 | 70.8 | 100 | 3.6 | 9.4 | 98.4 | 0.2 | 0.0 | 93.2 | 0.2 | 19.9 | 1.46 | -19.7 | 1.02 | 1.6 |
| 1993 | 0.89 | -4 | 70.8 | 1.04 | -3 | 70.8 | 102.6 | 2.6 | 9.4 | 104.5 | 6.0 | 0.0 | 94.6 | 1.5 | 19.9 | 1.43 | -2.1 | 1.00 | -1.7 |
| 1994 | 0.40 | -79 | 70.8 | 0.78 | -28 | 70.8 | 105.7 | 3.0 | 9.4 | 114.8 | 9.4 | 0.0 | 94.7 | 0.1 | 19.9 | 0.82 | -55.8 | 0.82 | -19.9 |
| 1995 | 0.59 | 38 | 70.8 | 0.68 | -15 | 70.8 | 108.3 | 2.4 | 9.4 | 94.2 | -19.8 | 0.0 | 96.8 | 2.2 | 19.9 | 1.08 | 27.4 | 0.74 | -9.6 |
| 1996 | 1.37 | 85 | 70.8 | 0.80 | 17 | 70.8 | 109.5 | 1.1 | 9.4 | 94.6 | 0.4 | 0.0 | 98.4 | 1.6 | 19.9 | 1.97 | 60.3 | 0.84 | 12.2 |
| 1997 | 0.89 | -43 | 70.8 | 0.96 | 19 | 70.8 | 111.5 | 1.8 | 9.4 | 100.0 | 5.6 | 0.0 | 100.0 | 1.6 | 19.9 | 1.46 | -29.9 | 0.96 | 13.7 |
| 1998 | 0.80 | -11 | 70.8 | 1.05 | 9 | 70.8 | 113.6 | 1.9 | 9.4 | 111.1 | 10.5 | 0.0 | 100.3 | 0.3 | 19.9 | 1.35 | -7.9 | 1.03 | 6.3 |
| 1999 | 0.83 | 5 | 70.8 | 0.88 | -18 | 70.8 | 115.4 | 1.6 | 9.4 | 125.7 | 12.3 | 0.0 | 101.0 | 0.7 | 19.9 | 1.40 | 3.5 | 0.90 | -12.6 |
| 2000 | 0.96 | 14 | 70.8 | 0.90 | 3 | 70.8 | 117.9 | 2.1 | 9.4 | 167.6 | 28.8 | 0.0 | 102.7 | 1.7 | 19.9 | 1.55 | 10.7 | 0.93 | 2.5 |
| 2001 | 1.80 | 62 | 72.6 | 1.22 | 30 | 72.6 | 120.8 | 2.4 | 8.3 | 250.1 | 40.0 | 0.0 | 103.9 | 1.2 | 19.0 | 2.46 | 45.8 | 1.16 | 22.4 |
| 2002 | 1.54 | -16 | 76.1 | 1.43 | 16 | 76.1 | 124.6 | 3.1 | 6.7 | 214.8 | -15.2 | 0.0 | 106.1 | 2.1 | 17.2 | 2.19 | -11.5 | 1.32 | 12.8 |
| 2003 | 1.33 | -15 | 74.1 | 1.55 | 8 | 74.1 | 127.8 | 2.5 | 7.0 | 225.0 | 4.6 | 0.0 | 107.8 | 1.6 | 19.0 | 1.97 | -10.4 | 1.41 | 6.4 |
| 2004 | 0.18 | -198 | 66.9 | 1.06 | -38 | 66.9 | 131.5 | 2.9 | 9.3 | 226.8 | 0.8 | 0.0 | 110.1 | 2.1 | 23.8 | 0.53 | -131.5 | 1.10 | -24.9 |
| 2005 | -0.19 | NA | 53.6 | 0.52 | -71 | 53.6 | 135.6 | 3.1 | 13.7 | 239.6 | 5.5 | 0.0 | 111.2 | 1.0 | 32.6 | NA | NA | 0.75 | -37.5 |
| 2006 | 1.62 | NA | 53.6 | 0.51 | -2 | 53.6 | 139.1 | 2.5 | 13.7 | 251.4 | 4.8 | 0.0 | *113.6* [5] | 2.1 | 32.6 | NA | NA | 0.75 | 0.0 |
| **Average Annual Growth Rate (%)** | | | | | | | | | | | | | | | | | | | |
| 1991-2005 | | NA | | | -3.55 | | | 2.90 | | | 6.50 | | | 1.57 | | | NA | | -2.02 |
| **1993-2002** | | **6.03** | | | **3.54** | | | **2.16** | | | **8.01** | | | **1.27** | | | **4.74** | | **3.10** |
| **1994-2004** | | **-0.08** | | | **3.00** | | | **2.18** | | | **6.81** | | | **1.51** | | | **-4.34** | | **2.93** |
| 2000-2005 | | NA | | | -11.06 | | | 2.80 | | | 7.14 | | | 1.59 | | | NA | | -4.15 |

° Source: Cost shares based on PEG research on Enbridge Gas Distribution.

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

[2] Source: Statistics Canada, Construction Union Wage Rate Index for Ontario with selected pay supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for natural gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at market prices.

[5] The GDP-IPI number for Ontario has not yet been released. Therefore, we approximated this number by adjusting the 2005 Ontario GDP-IPI information with the growth rate for the Canadian GDP-IPI i 2005-2006 period.

Table 13b

# Input Price Index: Geometric Decay Capital Cost for Union Gas

| | Capital (Unsmoothed) | | | Capital (Real Rate Smoothed) | | | Labour | | | Cost of Natural Gas | | | Materials and Services | | | IPI - Union Unsmoothed | | IPI - Union Smoothed | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Index[1] | Growth Rate (%) | Weight[o] (%) | Index[1] | Growth Rate (%) | Weight[o] (%) | Index[2] | Growth Rate (%) | Weight[o] (%) | Index[3] | Growth Rate (%) | Weight[o] (%) | Index[4] | Growth Rate (%) | Weight[o] (%) | Level | Growth Rate (%) | Level | Growth Rate (%) |
| 1988 | 0.58 | | | | | | 80.1 | | | 100.2 | | | 82.2 | | | 1.00 | | | |
| 1989 | 0.85 | 39 | 65.5 | | | 65.5 | 85.1 | 6.1 | 19.3 | 95.6 | -4.7 | 1.3 | 86.4 | 5.0 | 13.9 | 1.31 | 27.2 | | |
| 1990 | 1.04 | 19 | 65.5 | 0.85 | | 65.5 | 90.3 | 5.9 | 19.3 | 96.5 | 0.9 | 1.3 | 89.2 | 3.2 | 13.9 | 1.51 | 14.3 | | |
| 1991 | 1.23 | 17 | 65.5 | 1.06 | 22 | 65.5 | 96.5 | 6.6 | 19.3 | 98.2 | 1.7 | 1.3 | 93.0 | 4.2 | 13.9 | 1.73 | 13.2 | 1.00 | |
| 1992 | 0.93 | -28 | 65.5 | 1.08 | 2 | 65.5 | 100 | 3.6 | 19.3 | 98.4 | 0.2 | 1.3 | 93.2 | 0.2 | 13.9 | 1.45 | -17.9 | 1.02 | 1.8 |
| 1993 | 0.89 | -4 | 65.5 | 1.04 | -3 | 65.5 | 102.6 | 2.6 | 19.3 | 104.5 | 6.0 | 1.3 | 94.6 | 1.5 | 13.9 | 1.42 | -1.7 | 1.01 | -1.3 |
| 1994 | 0.40 | -79 | 65.5 | 0.78 | -28 | 65.5 | 105.7 | 3.0 | 19.3 | 114.8 | 9.4 | 1.3 | 94.7 | 0.1 | 13.9 | 0.85 | -51.2 | 0.84 | -18.0 |
| 1995 | 0.59 | 38 | 65.5 | 0.68 | -15 | 65.5 | 108.3 | 2.4 | 19.3 | 94.2 | -19.8 | 1.3 | 96.8 | 2.2 | 13.9 | 1.10 | 25.3 | 0.77 | -9.0 |
| 1996 | 1.37 | 85 | 65.5 | 0.80 | 17 | 65.5 | 109.5 | 1.1 | 19.3 | 94.6 | 0.4 | 1.3 | 98.4 | 1.6 | 13.9 | 1.92 | 55.9 | 0.86 | 11.4 |
| 1997 | 0.89 | -43 | 65.5 | 0.96 | 19 | 65.5 | 111.5 | 1.8 | 19.3 | 100.0 | 5.6 | 1.3 | 100.0 | 1.6 | 13.9 | 1.46 | -27.5 | 0.98 | 12.9 |
| 1998 | 0.80 | -11 | 65.5 | 1.05 | 9 | 65.5 | 113.6 | 1.9 | 19.3 | 111.1 | 10.5 | 1.3 | 100.3 | 0.3 | 13.9 | 1.36 | -7.0 | 1.04 | 6.1 |
| 1999 | 0.83 | 5 | 65.5 | 0.88 | -18 | 65.5 | 115.4 | 1.6 | 19.3 | 125.7 | 12.3 | 1.3 | 101.0 | 0.7 | 13.9 | 1.41 | 3.6 | 0.93 | -11.3 |
| 2000 | 0.96 | 14 | 66.0 | 0.90 | 3 | 66.0 | 117.9 | 2.1 | 18.6 | 167.6 | 28.8 | 2.5 | 102.7 | 1.7 | 12.9 | 1.57 | 10.8 | 0.96 | 3.2 |
| 2001 | 1.80 | 62 | 68.5 | 1.22 | 30 | 68.5 | 120.8 | 2.4 | 16.6 | 250.1 | 40.0 | 2.6 | 103.9 | 1.2 | 12.2 | 2.44 | 44.4 | 1.20 | 22.3 |
| 2002 | 1.54 | -16 | 70.7 | 1.43 | 16 | 70.7 | 124.6 | 3.1 | 14.7 | 214.8 | -15.2 | 2.0 | 106.1 | 2.1 | 12.6 | 2.19 | -10.8 | 1.35 | 11.8 |
| 2003 | 1.33 | -15 | 70.9 | 1.55 | 8 | 70.9 | 127.8 | 2.5 | 14.5 | 225.0 | 4.6 | 3.3 | 107.8 | 1.6 | 11.3 | 1.99 | -9.7 | 1.44 | 6.4 |
| 2004 | 0.18 | -198 | 63.0 | 1.06 | -38 | 63.0 | 131.5 | 2.9 | 18.3 | 226.8 | 0.8 | 4.0 | 110.1 | 2.1 | 14.6 | 0.58 | -123.8 | 1.14 | -23.3 |
| 2005 | -0.19 | NA | 51.8 | 0.52 | -71 | 51.8 | 135.6 | 3.1 | 25.0 | 239.6 | 5.5 | 5.6 | 111.2 | 1.0 | 17.6 | NA | NA | 0.80 | -35.7 |
| 2006 | 1.62 | NA | 51.8 | 0.51 | -2 | 51.8 | 139.1 | 2.5 | 25.0 | 251.4 | 4.8 | 5.6 | *113.6* [5] | 2.1 | 17.6 | NA | NA | 0.80 | 0.28 |
| **Average Annual Growth Rate (%)** | | | | | | | | | | | | | | | | | | | |
| 1991-2005 | | NA | | | -3.55 | | | 2.90 | | | 6.50 | | | 1.57 | | | NA | | -1.63 |
| **1993-2002** | | **6.03** | | | **3.54** | | | **2.16** | | | **8.01** | | | **1.27** | | | **4.83** | | **3.26** |
| **1994-2004** | | **-0.08** | | | **3.00** | | | **2.18** | | | **6.81** | | | **1.51** | | | **-3.88** | | **3.04** |
| 2000-2005 | | NA | | | -11.06 | | | 2.80 | | | 7.14 | | | 1.59 | | | NA | | -3.70 |

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

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

[2]Source: Statistics Canada, Construction Union Wage Rate Index for Ontario with selected pay supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for natural gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at market prices.

[5] The GDP-IPI number for Ontario has not yet been released. Therefore, we approximated this number by adjusting the 2005 Ontario GDP-IPI information with the growth rate for the Canadian GDP-IPI in the 2005-2006 period.

We do not believe that the unusual input price conditions of 2004 and 2005 are likely to repeat themselves during the prospective IR periods of the two companies. Accordingly, we excluded 2004 and 2005 from consideration in the calculation of the input price differential using the geometric decay approach. We sought, instead, a period ending before 2004 in which the start and end years had a similar real rate of return. The 1993-2002 period was chosen using these criteria. 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 data are available.

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 GDP-IPI as an output price index and the multifactor productivity ("MFP") index for the Canadian private business sector as a measure of the economy's TFP growth we can then calculate the trend in the economy's input prices.

Results for the 1993-2002 period are calculated and highlighted in Table 14 for reader convenience.[21] We found that the appropriate input price differentials for Enbridge and Union using GD capital costing were -0.16% and -0.33% respectively.[22] The small difference reflects chiefly Union's greater reliance on natural gas, which grew rapidly in price over the sample period.

Figure 3 suggests that the COS capital service price indexes are much less sensitive to the special events of the 2004-2005 period than are their GD counterparts. There is then no need for smoothing and we may reasonably choose 2005 as the end date for the calculation of IPDs. We chose 1998 as the corresponding start date since (from Table 12) it is a year with a similar weighted average cost of funds.

[21] We also highlight results for the 1994-2004 period, which also started and ended with similar real rates of return.

[22] Similar results obtained for the 1994-2004 period.

Table 14

# Input Price Differentials: Geometric Decay Capital Cost

| | Input Price Indexes | | | | | | | | | Input Price Differentials | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Canadian Economy | | | | | Enbridge (Growth Rate) | | Union (Growth Rate) | | (Economy - Enbridge) | | (Economy - Union) | |
| | GDP-IPI[1] | | MFP[2] | | Estimated | Not | Real Rate | Not | Real Rate | Not | Real Rate | Not | Real Rate |
| | Level | Growth Rate [A] (%) | Level | Growth Rate [B] (%) | Growth Rate [C]=A+B (%) | Smoothed[4] [D] (%) | Smoothed[4] [E] (%) | Smoothed[5] [F] (%) | Smoothed[5] [G] (%) | Smoothed [C]-[D] (%) | Smoothed [C]-[E] (%) | Smoothed [C]-[F] (%) | Smoothed [C]-[G] (%) |
| 1988 | 81.6 | | 101.2 | | | | | | | | | | |
| 1989 | 85.2 | 4.3 | 99.9 | -1.3 | 3.0 | 29.0 | NA | 27.2 | NA | -26.0 | NA | -24.2 | NA |
| 1990 | 88.4 | 3.7 | 97.7 | -2.2 | 1.5 | 14.9 | NA | 14.3 | NA | -13.4 | NA | -12.8 | NA |
| 1991 | 91.4 | 3.3 | 95.0 | -2.8 | 0.5 | 13.7 | NA | 13.2 | NA | -13.2 | NA | -12.7 | NA |
| 1992 | 93.0 | 1.7 | 95.9 | 0.9 | 2.7 | -19.7 | 1.6 | -17.9 | 1.8 | 22.4 | 1.1 | 20.6 | 0.9 |
| 1993 | 94.9 | 2.0 | 96.3 | 0.4 | 2.4 | -2.1 | -1.7 | -1.7 | -1.3 | 4.6 | 4.1 | 4.1 | 3.7 |
| 1994 | 96.3 | 1.5 | 99.0 | 2.8 | 4.2 | -55.8 | -19.9 | -51.2 | -18.0 | 60.0 | 24.1 | 55.5 | 22.2 |
| 1995 | 97.4 | 1.1 | 99.5 | 0.5 | 1.6 | 27.4 | -9.6 | 25.3 | -9.0 | -25.8 | 11.3 | -23.7 | 10.7 |
| 1996 | 98.5 | 1.1 | 98.7 | -0.8 | 0.3 | 60.3 | 12.2 | 55.9 | 11.4 | -60.0 | -11.9 | -55.6 | -11.0 |
| 1997 | 100.0 | 1.5 | 100.0 | 1.3 | 2.8 | -29.9 | 13.7 | -27.5 | 12.9 | 32.7 | -10.9 | 30.3 | -10.1 |
| 1998 | 101.3 | 1.3 | 101.1 | 1.1 | 2.4 | -7.9 | 6.3 | -7.0 | 6.1 | 10.3 | -3.9 | 9.4 | -3.7 |
| 1999 | 102.6 | 1.3 | 103.5 | 2.3 | 3.6 | 3.5 | -12.6 | 3.6 | -11.3 | 0.1 | 16.2 | 0.1 | 15.0 |
| 2000 | 105.0 | 2.3 | 106.1 | 2.5 | 4.8 | 10.7 | 2.5 | 10.8 | 3.2 | -5.9 | 2.3 | -6.0 | 1.6 |
| 2001 | 106.8 | 1.7 | 106.7 | 0.6 | 2.3 | 45.8 | 22.4 | 44.4 | 22.3 | -43.5 | -20.1 | -42.1 | -20.1 |
| 2002 | 109.3 | 2.3 | 108.9 | 2.0 | 4.4 | -11.5 | 12.8 | -10.8 | 11.8 | 15.9 | -8.5 | 15.2 | -7.4 |
| 2003 | 110.8 | 1.4 | 109.0 | 0.1 | 1.5 | -10.4 | 6.4 | -9.7 | 6.4 | 11.8 | -5.0 | 11.2 | -4.9 |
| 2004 | 112.7 | 1.7 | 109.5 | 0.5 | 2.2 | -131.5 | -24.9 | -123.8 | -23.3 | 133.7 | 27.0 | 126.0 | 25.5 |
| 2005 | 114.7 | 1.8 | *110.0* [3] | 0.5 | 2.3 | NA | -37.5 | NA | -35.7 | NA | 39.8 | NA | 38.0 |
| 2006 | 116.8 | 1.8 | *110.0* [3] | 0.5 | 2.3 | NA | 0.0 | NA | 0.3 | NA | 2.3 | NA | 2.0 |
| **Average Annual Growth Rate (%)** | | | | | | | | | | | | | |
| 1991-2005 | | 1.62 | | 1.05 | 2.67 | NA | -2.02 | NA | -1.63 | NA | 4.69 | NA | 4.30 |
| **1993-2002** | | **1.57** | | **1.37** | **2.94** | **4.74** | **3.10** | **4.83** | **3.26** | **-1.81** | **-0.16** | **-1.89** | **-0.33** |
| 1994-2004 | | 1.57 | | 1.01 | 2.58 | -4.34 | 2.93 | -3.88 | 3.04 | 6.92 | -0.35 | 6.46 | -0.46 |
| 2000-2005 | | 1.77 | | 0.73 | 2.50 | NA | -4.15 | NA | -3.70 | NA | 6.65 | NA | 6.20 |

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

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

[3] The MFP level and growth rates for 2005 and 2006 were imputed using the 2004 MFP Growth Rate due to a lack of data.

[4] See Tables 12 and 13a for details of calculations

[5] Source: See Tables 12 and 13b for details of calculations.

Input price trends using the alternative COS approach to capital costing are reported in Tables 15a and 15b. These employ the same price subindexes for labour, gas, and M&S that are used with the GD costing. It can be seen that these indexes did not exhibit unusual behavior in 2004 and 2005. The decline in the indexes in 2005 was due solely to the fairly substantial decline in the weighted average cost of funds.

Input price differentials using COS costing are reported in Table 16. Results for the 1998-2005 period are calculated and highlighted for reader convenience. We found that the appropriate input price differentials for Enbridge and Union using COS costing are -0.37% and -0.35%, respectively. These differentials are similar to those obtained using GD capital costing. Results using both methods substantiate the notion that the input price trends of Ontario gas utilities are considerably more rapid than the trend in GDPIPI FDD.

The greater stability of the COS input price index is a major advantage in the calculation of IPDs. The choice of an appropriate sample period for IPD calculations will be less controversial The COS method can thus serve as an alternative means of capital costing in addition to providing a useful point of comparison for IPDs calculated using GD costing.

## 3.6 Stretch Factor

The stretch factor term of the X factor was noted in Section 2 to reflect expectations concerning the potential for better performance under the stronger incentives that may be generated by the IR plan. We have relied on two sources in developing our straw man stretch factor proposals. 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 energy utilities in approved 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 stylized regulatory systems.[23] By comparing the performance expected under an approximation to the company's current system to that expected under an approximation of the envisioned IR plan, we can estimate the expected

[23] Details of our incentive power research will be released in a later document.

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. Table 15a

Table 15a

# Input Price Index with COS Capital Cost: Enbridge Gas Distribution

| | Capital (COSR Method) | | | Labour | | | Natural Gas | | | Materials and Services | | | Input Price Index | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Index[1] | Growth Rate (%) | Weight[0] (%) | Index[2] | Growth Rate (%) | Weight[0] (%) | Index[3] | Growth Rate (%) | Weight[0] (%) | Index[4] | Growth Rate (%) | Weight[0] (%) | Index | Growth Rate (%) |
| 1990 | 0.643 | | 71.8 | 90.3 | | 9.0 | 96.5 | | 0.0 | 89.2 | | 19.2 | 1.000 | |
| 1991 | 0.639 | -0.6 | 71.8 | 96.5 | 6.6 | 9.0 | 98.2 | 1.7 | 0.0 | 93.0 | 4.2 | 19.2 | 1.009 | 0.9 |
| 1992 | 0.714 | 11.2 | 71.8 | 100 | 3.6 | 9.0 | 98.4 | 0.2 | 0.0 | 93.2 | 0.2 | 19.2 | 1.098 | 8.4 |
| 1993 | 0.721 | 0.9 | 71.8 | 102.6 | 2.6 | 9.0 | 104.5 | 6.0 | 0.0 | 94.6 | 1.5 | 19.2 | 1.111 | 1.1 |
| 1994 | 0.784 | 8.5 | 71.8 | 105.7 | 3.0 | 9.0 | 114.8 | 9.4 | 0.0 | 94.7 | 0.1 | 19.2 | 1.184 | 6.4 |
| 1995 | 0.802 | 2.2 | 71.8 | 108.3 | 2.4 | 9.0 | 94.2 | -19.8 | 0.0 | 96.8 | 2.2 | 19.2 | 1.210 | 2.2 |
| 1996 | 0.815 | 1.6 | 71.8 | 109.5 | 1.1 | 9.0 | 94.6 | 0.4 | 0.0 | 98.4 | 1.6 | 19.2 | 1.230 | 1.6 |
| 1997 | 0.778 | -4.7 | 71.8 | 111.5 | 1.8 | 9.0 | 100.0 | 5.6 | 0.0 | 100.0 | 1.6 | 19.2 | 1.195 | -2.9 |
| 1998 | 0.763 | -2.0 | 71.8 | 113.6 | 1.9 | 9.0 | 111.1 | 10.5 | 0.0 | 100.3 | 0.3 | 19.2 | 1.181 | -1.2 |
| 1999 | 0.947 | 21.6 | 71.8 | 115.4 | 1.6 | 9.0 | 125.7 | 12.3 | 0.0 | 101.0 | 0.7 | 19.2 | 1.383 | 15.8 |
| 2000 | 0.960 | 1.4 | 71.8 | 117.9 | 2.1 | 9.0 | 167.6 | 28.8 | 0.0 | 102.7 | 1.7 | 19.2 | 1.403 | 1.5 |
| 2001 | 1.089 | 12.6 | 70.5 | 120.8 | 2.4 | 9.0 | 250.1 | 40.0 | 0.0 | 103.9 | 1.2 | 20.5 | 1.542 | 9.4 |
| 2002 | 0.977 | -10.8 | 71.3 | 124.6 | 3.1 | 8.1 | 214.8 | -15.2 | 0.0 | 106.1 | 2.1 | 20.6 | 1.438 | -7.0 |
| 2003 | 1.004 | 2.7 | 67.5 | 127.8 | 2.5 | 8.7 | 225.0 | 4.6 | 0.0 | 107.8 | 1.6 | 23.7 | 1.473 | 2.4 |
| 2004 | 1.045 | 4.0 | 66.4 | 131.5 | 2.9 | 9.4 | 226.8 | 0.8 | 0.0 | 110.1 | 2.1 | 24.2 | 1.525 | 3.5 |
| 2005 | 0.996 | -4.8 | 65.9 | 135.6 | 3.1 | 10.1 | 239.6 | 5.5 | 0.0 | 111.2 | 1.0 | 24.0 | 1.485 | -2.7 |
| **Average Annual Growth Rates (%)** | | | | | | | | | | | | | | |
| 1990-2005 | | 2.92 | | | 2.71 | | | 6.06 | | | 1.47 | | | 2.64 |
| **1997-2003** | | **4.24** | | | **2.27** | | | **13.52** | | | **1.25** | | | **3.49** |
| **1998-2005** | | **3.80** | | | **2.53** | | | **10.98** | | | **1.47** | | | **3.28** |
| 2000-2005 | | 0.73 | | | 2.80 | | | 7.14 | | | 1.59 | | | 1.14 |

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

[1] PEG calculation using Enbridge plant data.

[2] Source: Statistics Canada, Construction Union Wage Rate Index with selected pay supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for natural gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at market prices.

Table 15b

# Input Price Index with COS Capital Cost: Union Gas

| Year | Capital (COSR Method) Index[1] | Capital Growth Rate (%) | Capital Weight[0] (%) | Labour Index[2] | Labour Growth Rate (%) | Labour Weight[0] (%) | Natural Gas Index[3] | Natural Gas Growth Rate (%) | Natural Gas Weight[0] (%) | Materials and Services Index[4] | Materials and Services Growth Rate (%) | Materials and Services Weight[0] (%) | Input Price Index Index | Input Price Index Growth Rate (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 0.636 | | 62.5 | 90.3 | | 21.0 | 96.5 | | 1.4 | 89.2 | | 15.1 | 1.000 | |
| 1991 | 0.646 | 1.5 | 62.5 | 96.5 | 6.6 | 21.0 | 98.2 | 1.7 | 1.4 | 93.0 | 4.2 | 15.1 | 1.030 | 2.963 |
| 1992 | 0.710 | 9.5 | 62.5 | 100 | 3.6 | 21.0 | 98.4 | 0.2 | 1.4 | 93.2 | 0.2 | 15.1 | 1.102 | 6.710 |
| 1993 | 0.715 | 0.8 | 62.5 | 102.6 | 2.6 | 21.0 | 104.5 | 6.0 | 1.4 | 94.6 | 1.5 | 15.1 | 1.116 | 1.329 |
| 1994 | 0.777 | 8.3 | 62.5 | 105.7 | 3.0 | 21.0 | 114.8 | 9.4 | 1.4 | 94.7 | 0.1 | 15.1 | 1.185 | 5.946 |
| 1995 | 0.815 | 4.8 | 62.5 | 108.3 | 2.4 | 21.0 | 94.2 | -19.8 | 1.4 | 96.8 | 2.2 | 15.1 | 1.228 | 3.555 |
| 1996 | 0.818 | 0.4 | 62.5 | 109.5 | 1.1 | 21.0 | 94.6 | 0.4 | 1.4 | 98.4 | 1.6 | 15.1 | 1.236 | 0.713 |
| 1997 | 0.773 | -5.7 | 62.5 | 111.5 | 1.8 | 21.0 | 100.0 | 5.6 | 1.4 | 100.0 | 1.6 | 15.1 | 1.202 | -2.851 |
| 1998 | 0.753 | -2.5 | 62.5 | 113.6 | 1.9 | 21.0 | 111.1 | 10.5 | 1.4 | 100.3 | 0.3 | 15.1 | 1.190 | -1.007 |
| 1999 | 0.926 | 20.6 | 62.5 | 115.4 | 1.6 | 21.0 | 125.7 | 12.3 | 1.4 | 101.0 | 0.7 | 15.1 | 1.361 | 13.494 |
| 2000 | 0.940 | 1.5 | 64.3 | 117.9 | 2.1 | 19.5 | 167.6 | 28.8 | 2.6 | 102.7 | 1.7 | 13.6 | 1.391 | 2.175 |
| 2001 | 1.067 | 12.7 | 63.6 | 120.8 | 2.4 | 19.2 | 250.1 | 40.0 | 3.0 | 103.9 | 1.2 | 14.1 | 1.536 | 9.871 |
| 2002 | 0.961 | -10.5 | 65.4 | 124.6 | 3.1 | 17.4 | 214.8 | -15.2 | 2.4 | 106.1 | 2.1 | 14.8 | 1.442 | -6.307 |
| 2003 | 0.985 | 2.5 | 61.7 | 127.8 | 2.5 | 19.0 | 225.0 | 4.6 | 4.4 | 107.8 | 1.6 | 14.9 | 1.477 | 2.427 |
| 2004 | 1.022 | 3.7 | 59.5 | 131.5 | 2.9 | 20.1 | 226.8 | 0.8 | 4.4 | 110.1 | 2.1 | 16.0 | 1.525 | 3.169 |
| 2005 | 0.970 | -5.2 | 59.5 | 135.6 | 3.1 | 21.0 | 239.6 | 5.5 | 4.7 | 111.2 | 1.0 | 14.8 | 1.494 | -2.062 |
| **Average Annual Growth Rates (%)** | | | | | | | | | | | | | | |
| 1990-2005 | | 2.81 | | | 2.71 | | | 6.06 | | | 1.47 | | | 2.68 |
| **1997-2003** | | **4.04** | | | **2.27** | | | **13.52** | | | **1.25** | | | **3.44** |
| **1998-2005** | | **3.61** | | | **2.53** | | | **10.98** | | | **1.47** | | | **3.25** |
| 2000-2005 | | 0.64 | | | 2.80 | | | 7.14 | | | 1.59 | | | 1.42 |

[0]Weights based on research for Union Gas

[1] PEG calculation using Union plant data.

[2] Source: Statistics Canada, Construction Union Wage Rate Index with selected pay supplements.

[3] Source: Statistics Canada, Raw Materials Price Index for natural gas.

[4] Source: Statistics Canada, Ontario GDP-IPI at market prices.

Table 16

# Input Price Differentials with COS Capital Cost

| | Ontario Economy | | | | | Ontario Gas Industry | | Input Price Differential | |
|---|---|---|---|---|---|---|---|---|---|
| | GDP-IPI[1] | | MFP[2] | | Implied IPI | | | | |
| | Level | Growth Rate [A] (%) | Level | Growth Rate [B] (%) | Growth Rate [C]=A+B (%) | Enbridge[4] [D] (%) | Union[5] [E] (%) | Enbridge [C]-[D] (%) | Union [C]-[E] (%) |
| 1990 | 89.2 | | 97.7 | | | | | | |
| 1991 | 92.3 | 3.4 | 95.0 | -2.8 | 0.6 | 0.9 | 3.0 | -0.3 | -2.3 |
| 1992 | 93.4 | 1.2 | 95.9 | 0.9 | 2.1 | 8.4 | 6.7 | -6.3 | -4.6 |
| 1993 | 95.3 | 2.0 | 96.3 | 0.4 | 2.4 | 1.1 | 1.3 | 1.3 | 1.1 |
| 1994 | 96.4 | 1.1 | 99.0 | 2.8 | 3.9 | 6.4 | 5.9 | -2.5 | -2.0 |
| 1995 | 97.6 | 1.2 | 99.5 | 0.5 | 1.7 | 2.2 | 3.6 | -0.5 | -1.8 |
| 1996 | 98.6 | 1.0 | 98.7 | -0.8 | 0.2 | 1.6 | 0.7 | -1.4 | -0.5 |
| 1997 | 100.0 | 1.4 | 100.0 | 1.3 | 2.7 | -2.9 | -2.9 | 5.6 | 5.6 |
| 1998 | 101.5 | 1.5 | 101.1 | 1.1 | 2.6 | -1.2 | -1.0 | 3.8 | 3.6 |
| 1999 | 102.6 | 1.1 | 103.5 | 2.3 | 3.4 | 15.8 | 13.5 | -12.3 | -10.1 |
| 2000 | 105.1 | 2.4 | 106.1 | 2.5 | 4.9 | 1.5 | 2.2 | 3.4 | 2.7 |
| 2001 | 106.9 | 1.7 | 106.7 | 0.6 | 2.3 | 9.4 | 9.9 | -7.2 | -7.6 |
| 2002 | 109.2 | 2.1 | 108.9 | 2.0 | 4.2 | -7.0 | -6.3 | 11.2 | 10.5 |
| 2003 | 110.7 | 1.4 | 109.0 | 0.1 | 1.5 | 2.4 | 2.4 | -1.0 | -1.0 |
| 2004 | 112.5 | 1.6 | 109.5 | 0.5 | 2.1 | 3.5 | 3.2 | -1.4 | -1.1 |
| 2005 | 114.3 | 1.6 | *110.0* [3] | *0.5* | 2.0 | -2.7 | -2.1 | 4.7 | 4.1 |
| **Average Annual Growth Rates (%)** | | | | | | | | | |
| 1990-2005 | | 1.65 | | 0.79 | 2.44 | 2.64 | 2.68 | -0.19 | -0.23 |
| 1997-2003 | | 1.69 | | 1.44 | 3.13 | 3.49 | 3.44 | -0.36 | -0.31 |
| **1998-2005** | | **1.70** | | **1.21** | **2.90** | **3.28** | **3.25** | **-0.37** | **-0.35** |
| 2000-2005 | | 1.68 | | 0.72 | 2.40 | 1.14 | 1.42 | 1.27 | 0.98 |

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

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

[3] The MFP level and growth rate for 2005 were imputed using the 2004 MFP growth rate due to a lack of data.

[4] Source: See Table 15a for details of calculations.

[5] Source: See Table 15b for details of calculations.

The straw man productivity differential for Enbridge reflects exclusively the TFP trends of U.S. gas utilities. Assuming that these utilities held rate cases 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%.

The straw man productivity differential for Union is based partly on U.S. TFP trends and partly on the recent trend of Union. Union completed only one rate case in the six-year 2000-2005 period but its productivity growth target is based 50% on U.S. results. We may thus reason that its target reflects 4.5 year regulatory lag. Our incentive power research suggests that annual performance growth should accelerate in this case by 0.2% on average. Half of this is 0.1%.

These findings suggest that there are grounds to assign different stretch factors to the two utilities. We, accordingly, suggest as a just and reasonable straw man proposal that the stretch factors for the two companies be set half way between the incentive power prediction and the 0.5% precedential norm. This procedure results in stretch factors of 0.46 for Enbridge and 0.30 for Union.

### 3.7 Summary of Results

For reader convenience, we now summarize the results of our research to calculate X factors for the summary PCIs of Enbridge and Union.

| | **Geometric Decay** | | **COS** | |
|---|---|---|---|---|
| | **Enbridge** | **Union** | **Enbridge** | **Union** |
| $TFP^{Industry}$ [A] | 1.37 | 1.63 | 1.22 | 1.58 |
| $TFP^{Economy}$ [B] | 1.37 | 1.37 | 1.21 | 1.21 |
| **PD [C=A-B]** | **-0.00** | **0.26** | **-0.01** | **0.37** |
| Input $Prices^{Economy}$ [D] | 2.94 | 2.94 | 2.90 | 2.90 |
| Input $Prices^{Industry}$ [E] | 3.10 | 3.26 | 3.28 | 3.25 |
| **IPD [F=D-E]** | **-0.16** | **-0.33** | **-0.37** | **-0.35** |
| $gOutput^{Revenue\text{-}Weighted}$ [G] | 2.08 | 1.05 | 2.08 | 1.05 |

| | | | | |
|---|---|---|---|---|
| Output$^{\text{Elasticity-Weighted}}$ [H] | 2.57 | 1.78 | 2.57 | 1.78 |
| **AU [I=G-H]** | **-0.49** | **-0.73** | **-0.49** | **-0.73** |
| **Stretch [J]** | **0.46** | **0.30** | **0.46** | **0.30** |
| **X [C+F+I+J]** | **-0.19** | **-0.50** | **-0.39** | **-0.41** |

It can be seen that both approaches would sanction overall growth in gas utility rates that is broadly similar to the growth in the GDPIPI FDD. The average X factors for the two companies are very similar to the two capital costing approaches (-.255 for GD and -.335 for COS). However, the X factors for the individual companies using COS differ considerably from those using the GD approach. The difference is attributable chiefly to the more sensitive treatment of the cost impact of plant additions under COS.

## 3.8 Price Caps for Service Groups

Price caps for specific service groups were established by calculating X factors that featured the four terms from the summary PCI and a special adjustment term, ADJ, that varied by service group. Original theoretical and empirical research was undertaken to provide a foundation for the design of this term. The basic intuition is that the PCI for a specific service group should reflect the manner in which its impact on revenue growth and cost growth differs from the impact of all services. Details of the theory are set forth in Section A.7.4 of the Appendix.

Regarding empirical implementation, we gauge the differential impact of services on revenue growth (the "revenue effect") using revenue-weighted output indexes. This is a matter of taken the difference between the trends in the output of the service group and total output. We gauge the differential impact of services on cost using the growth rates of individual service quantities and our econometric estimates of cost elasticities.

To implement the adjustment, we propose that the PCIs for all service groups have a GDPIPI-X growth rate formula in which the X factor has five terms. Four of these terms are the same ones featured in the X factor of the summary PCI. The fifth is a special adjustment factor ("ADJ") that is specific to the service group. Each ADJ is the sum of terms that represent the special revenue effect and cost effect of the service group.

As a just and reasonable straw man, we propose that there be separate PCIs for all of the rate classes that contain residential customers. All other service classes of Enbridge and Union would be subject to common PCIs. In table 17 we provide information on the

Table 17

# Calculation of the ADJ Factors

| Company<br>Service | Share Volume<br>Residential (2002) | Revenue Effect<br>[A] | Cost Effect<br>[B] | ADJ<br>[A+B] |
|---|---|---|---|---|
| **Enbridge** | | | | |
| Rate 1 (Residential) | 100% | 0.68% | -1.42% | -0.74% |
| Rate 6 (General Services) | 0% | -0.40% | 2.06% | 1.66% |
| Rate 100 (Large Volume Firm) | 0% | -2.01% | 2.51% | 0.50% |
| All Non-Residential Services | 0% | -0.85% | 2.21% | 1.36% |
| **Union** | | | | |
| Rate 01 (General Services North) | 75% | -1.13% | 0.81% | -0.32% |
| Rate M2 (General Services South) | 54% | 0.39% | -0.02% | 0.37% |
| Rate 10 (General Services North) | 0% | -0.21% | 0.97% | 0.76% |
| All Non-Residential Services | 0% | -0.16% | -0.36% | -0.52% |

calculation of the ADJ factors for each service group and a notion of the growth trend of the resultant PCIs. It can be seen that the service classes that include service to residential customers generally have more negative ADJ factors. This would cause residential customers to pay for the manner in which growth in service accelerates unit cost growth. The -0.52% ADJ for the (entirely) non-residential services of Union is something of an anomaly and will be the subject of ongoing investigation.

Here are the PCIs for individual service groups that result from our calculations using GD capital costing. We calculate indicated PCI growth for each group by taking the difference between the recent trends in the GDPIPI and the straw man X factors.

### Service Group PCIs

| Company | Service Group | Recent GDPIPI Trend [A] | Sum of Common Terms [B] | ADJ [C] | Total X Factor [D]=B+C | Indicated PCI Growth [A]-[D] |
|---|---|---|---|---|---|---|
| Enbridge | Rate 1 | 1.77 | -0.19 | -0.74 | -0.93 | 2.70 |
| | Nonresidential | 1.77 | -0.19 | 1.36 | 1.17 | 0.60 |
| Union | Rate M2 | 1.77 | -0.50 | 0.37 | -0.13 | 1.90 |
| | Rate 01 | 1.77 | -0.50 | -0.32 | -0.82 | 2.50 |
| | Nonresidential | 1.77 | -0.50 | -0.52 | -1.02 | 2.79 |

Results for the Union service groups must be interpreted cautiously since rates M2 and 01 both contain a mix of residential and business customers.

Table 18

# Econometric Models For Weather Normalization: U.S. Gas Industry

## VARIABLE KEY

yvrc = Residential and Commercial Throughput
yvres= Residential Throughput
yvcom= Commercial Throughput
HDD= Heating Degree Days for Each Region

| **Dependent Variable** | **ycrc** | | **yvres** | | **yvcom** | |
|---|---|---|---|---|---|---|
| | **Parameter Estimate[1]** | **T-statistic** | **Parameter Estimate** | **T-statistic** | **Parameter Estimate** | **T-statistic** |
| constant | 0.009 | 2.172 | 0.008 | 1.976 | 0.011 | 1.772 |
| HDD | 0.355 | 12.374 | 0.418 | 14.814 | 0.256 | 5.982 |
| sample period | 1994-2005 | | 1994-2005 | | 1994-2005 | |

1. Each HDD parameter is the elasticity of volume with respect to HDD due to the double log form of the model.

Table 19

# Econometric Model of Total Gas Utility Cost

### VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
VRC = Weather Adjusted Residential & Commercial Deliveries
VO = Other Deliveries
NIM = % Non-Iron Miles in Distribution Miles
NE = Number of Electric Customers
UD = Urban Core Dummy
Trend = Time Trend

| EXPLANATORY VARIABLE | ESTIMATED COEFFICIENT | T-STATISTIC | EXPLANATORY VARIABLE | ESTIMATED COEFFICIENT | T-STATISTIC |
|---|---|---|---|---|---|
| **L** | 0.222 | 15.20 | **VRC** | 0.132 | 4.37 |
| LL | -0.372 | -2.86 | VRCVRC | -0.564 | -3.28 |
| LK | -0.097 | -6.90 | VRCVO | 0.106 | 2.11 |
| LN | 0.032 | 2.78 | | | |
| LVRC | -0.051 | -4.84 | **VO** | 0.095 | 4.77 |
| LVO | 0.009 | 2.27 | VOVO | 0.118 | 5.93 |
| LTrend | 0.001 | 0.41 | | | |
| | | | **NIM** | -0.627 | -11.81 |
| **K** | 0.562 | 93.01 | | | |
| KK | 0.158 | 11.75 | **NE** | -0.006 | -5.97 |
| KN | -0.101 | -6.99 | | | |
| KVRC | 0.081 | 5.95 | **UD** | 0.045 | 3.42 |
| KVO | 0.024 | 5.97 | | | |
| KTrend | 0.007 | 6.61 | Trend | -0.011 | -4.99 |
| | | | | | |
| **N** | 0.645 | 17.49 | Constant | 8.177 | 369.38 |
| NN | 0.187 | 0.94 | | | |
| NVRC | 0.191 | 1.09 | System Rbar-Squared | 0.983 | |
| NVO | -0.216 | -3.83 | | | |
| | | | Sample Period | 1994-2004 | |
| | | | Number of Observations | 396 | |

# Appendix

This appendix contains additional details of our TFP research for the Ontario Energy Board. 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 discuss the econometric cost research. The mathematical logic for our approach to PCI design is detailed in section A.7. The qualifications of the authors are discussed in A.8.

## 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.

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

Here in each year $t$,

$\textit{Output Quantities}_t$ = Output quantity index

$Y_{i,t}$ = Aggregate measure of output $i$ for companies in the region.

$SE_i$ = 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 general formula.

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

Here in each year $t$,

$Output\ Quantities_t$ = Output quantity index

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

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

It can be seen that the growth rate of the index is 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 pact 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 used fixed revenue weights for each company that were based on its revenue shares in 2005.

### A.1.2 Weather Normalization of Volume Data

Weather adjusted delivery volumes for both Union and Enbridge were computed in the same way. In general, this involved adjusting the volumes for major service classes with heat sensitive loads. We adjusted the volumes for Union Gas rates 01 and 10 and Enbridge rates 1, 6, and 10.

The weather adjustment involved two separate steps. In the first step, we determined the impact of heating degree day (HDD) growth on long term delivery growth. We used US delivery volumes and heating degree days data to accomplish this.

In particular, we regressed the growth rates of residential, residential and commercial, commercial deliveries on the growth rate of HDDs to obtain coefficients that indicate the impact of HDD growth on these categories of deliveries. We used the data from 36 US gas utilities, covering the years 1994-2005, to determine the impact of HDD growth on residential, residential and commercial, and commercial deliveries growth. The regression model used is:

$$\ln(yv_t / yv_{t-1}) = \alpha_o + \alpha_d * \ln(HDD_t / HDD_{t-1}) + \varepsilon$$

where the term on the left hand side is the logarithmic growth of deliveries from year *t-1* to year *t* and the second term on the right hand side is the parameter of the logarithmic growth of heating degree days, to be estimated, times the growth of heating degree days from year *t-1* to year *t*. The first term on the right hand side is an intercept variable, that is estimated, and the last one is the stochastic term of the regression.

Table 18 provides the parameter estimates from the three regressions undertaken using the US data. We note that the parameter estimates or coefficients of all the regressions are positive, indicating that growth in HDD affects growth in volume positively. While the signs of the coefficients indicate the direction of the effect of heating degree days growth on volume growth, the magnitudes reflect the extent of this effect. For instance, the coefficient from the regression of residential and commercial delivery growth on heating degree days growth indicates that for a 1% growth in heating degree days, residential and commercial deliveries grow by 0.36%.

Once we obtained these parameter estimates we weather normalized the residential and commercial delivery volumes of Enbridge and Union volumes by removing the effect of actual HDDs and using instead the effect of the average HDDs over the six year sample period. The formula for this purpose is:

$$\ln(yv_t) + \hat{\alpha}_d * \ln(average(HDD) / HDD_t)$$

where $\hat{\alpha}_d$ is the parameter estimate from our regression. For example, as noted above, the value of this parameter estimate is 0.36 for the residential and commercial volume regression. Union's deliveries in rate class 01 were normalized using the coefficient from the residential and commercial deliveries regression while those in rate class 10 were normalizes using the coefficient from the commercial deliveries regression. Enbridge's rate class 1 deliveries were normalized using the coefficient from the residential deliveries regression while those from rates 6 and 100 were normalized using the coefficient from the residential and commercial, and commercial deliveries regressions, respectively. The value that is given by the above formula is then exponentiated to obtain the weather adjusted delivery values.

## A.2 Price Indexes

The growth rate of a summary input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

### A.2.1 Input 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:

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

Here 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.2.2 Output Price Indexes

The flexible-weight output price indexes used in this study are calculated using the following general formula.

$$\ln\left( \frac{\text{Rates}_t}{\text{Rates}_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left( SR_{i,t} + SR_{i,t-1} \right) \cdot \ln\left( \frac{P_{i,t}}{P_{i,t-1}} \right). \qquad [A4]$$

Here in each year *t*,

$Rates_t$ = Output price index

$P_{i,t}$ = Rate element i

$SR_{i,t}$ = Share of rate element I in total base rate revenue

The fixed-rate output price indexes fix the revenue shares at their 2005 values.

## A.3 Input Quantity Indexes

### A.3.1 Index Form

The input quantity index for each company included in the TFP research was of Törnqvist form.[24] This means that its annual growth rate was determined by the following general formula:

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

Here in each year *t*,

$InputQuantities_t$ = Input quantity index

$X_{j,t}$ = 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. The input quantity trend for each region considered was a size-weighted average of the growth rates of the companies in that region.[25]

### 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,

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j . \quad \text{[A6]}$$

[24] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).
[25] In the case of power distribution only one region --- the nation --- was considered, as noted above.

## A.4 Capital Cost

A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[26] It facilitates the use of benchmarking of cost data for utilities with different plant vintages. In this section, we explain the calculation of capital costs, prices, and quantities using the geometric decay and COS 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 our gas distribution research there is only one category of plant. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering. In constructing capital quantity indexes for gas we took 1983, 1985 and 1989 as the benchmark or starting years for the U.S. utilities, Enbridge, and Union respectively. 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.[27] The construction cost indexed used in the Ontario calculations was based on the trend in an index of power distribution construction costs as adjusted for the difference

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

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

between the trends in the Handy Whiteman Indexes of trends in the construction ocsts of U.S. gas utilities and power distribution utilities.

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

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

Here, the parameter *d* is the economic depreciation rate and $VI_{j,t}$ is the value of gross additions to utility plant. The economic depreciation rate was calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category used in the U.S. research was derived from data reported by the BEA. The depreciation rates applied to the Ontario utilities were based on a depreciation study provided by Union.

The full formula for the capital service price indexes based on geometric decay that were used in the input price research is

$$WKS_{j,t} = d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A7]$$

The first term in the expression corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility. In this formula, $r_t$ is the opportunity cost of plant ownership per dollar of plant value. As a proxy for this, we calculated the user cost of capital for the U.S. economy using data in the National Income and Product Accounts (NIPA). This variable reflects returns on equity as well as bond yields. The NIPA accounts are published by the BEA in its *Survey of Current Business* series. In the input price indexes for Ontario, we used an average of the corporate long bond yield and Board-approved ROEs for Enbridge and Union.

### 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 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

$WKA_{t-s}$ = Unit cost of plant installed in year t-s (the "price" of capital assets)

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

$xk_t$ = 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

$N$ = Service life of Tx plant

$I_t$ = Interest rate

$WKS_t$ = Price of capital service

Basic Assumptions

The analysis is based on several assumptions.

(1) All kinds of plant have the same service life N.

(2) Full 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

(3) The price cap index is not designed to recover changes in taxes.

Straightforward adjustments to the formulas are possible if more realistic alternatives to these assumptions are needed.

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,

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s}\right) \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s} \left(1/N\right) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s}\right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{\left(1/N\right) \cdot a_{t-s}}{xk_{t-1}}. \end{aligned} \quad [A9]$$

where, as per assumption 2 above,

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

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

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}.$$

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

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \quad [A10]$$

Equations [A8] and [A9] together imply that,

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

Here,

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

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 reflects a weighted average of the capital asset prices in the N most recent years (including the current year). The weight for each year, t-s, is the estimated share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year This share will be larger the more recent the plant addition year (due to construction cost inflation) and the larger were the plant additions in that year. This average asset price rises over time as the price for each of the 40 years is replaced with the higher price 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 assets service life is 100%.[28]

Simplifications

The implementation of this formula obviously entails calculations of capital quantities that are at best burdensome and at worst impossible. Simplifications of the formula should thus be entertained. One possibility is to assume a standard triangularized weighted averaging in lieu of weights based on a company's actual capital quantities.

$$WKS_t = \sum_{s=1}^{N} \frac{N-s+1}{\sum_{s=1}^{N} N-s+1} \cdot WKA_{t-s} \cdot I_t + \sum_{s=1}^{N} \frac{N-s+1}{\sum_{s=1}^{N} N-s+1} \cdot WKA_{t-s} \cdot \frac{1}{N-s+1}$$
$$= \sum_{s=1}^{N} \frac{N-s+1}{\sum_{s=1}^{N} N-s+1} \cdot WKA_{t-s} \cdot I_t + \frac{\sum_{s=1}^{N} WKA_{t-1}}{N} \cdot \frac{N}{\sum_{s=1}^{N} N-s+1}$$

As another simplification, suppose that there is book valuation of capital but a geometric decay of plant where *d* is the (constant) rate of decay. Then

$$ck_t = ck_t^{opportunity} + ck_t^{depreciation}$$
$$= \sum_{s=0}^{N-1} WKA_{t-s} \cdot xk_{t-1}^{t-s} \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s} \cdot xk_t^{t-s} \cdot d$$
$$= xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot d$$
$$= xk_t \cdot \left( \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \left( I_t + d \right)$$
$$= xk_t \cdot WKS_t^{GD}.$$

where

$$WKS_t^{GD} = \left( \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot \left( I_t + d \right).$$

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

A variety of further simplifying assumptions are possible with the geometric decay approach regarding the weighting of the capital asset prices. One is the triangularized weighting discussed above. Here,

$$WKS_t^{GD/TWA} = \left( \sum_{s=0}^{N-1} \frac{N-s}{\sum_{s=0}^{N-1} N-S} \cdot WKA_{t-s} \right) \cdot \left( I_t + d \right). \qquad [A12]$$

## A.5 TFP Growth Rates and Trends

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

$$\ln\left( \frac{TFP_t}{TFP_{t-1}} \right) = \ln\left( \frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) - \ln\left( \frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right). \qquad [A13]$$

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 normal pace 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 it performs 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. Here is a simple example of a linear cost model

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t} \qquad \text{[A14]}$$

where, 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.

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t}\,. \qquad \text{[A15]}$$

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.[29]

A more sophisticated translog functional form was employed in our econometric research for the Board.[30] This very flexible function is common in econometric cost research, and by some accounts the most reliable of several available flexible forms.[31] Here is an analogous cost function of translog form.

$$\begin{aligned}\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} \\ + a_4 \cdot \ln W_{h,t} \cdot \ln W_{h,t} + a_5 \cdot \ln W_{h,t} \cdot \ln N_{h,t} + e_{h,t}\end{aligned} \qquad \text{[A16]}$$

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

29 Cost elasticities are not constant in the linear model that is exemplified by equation [A13].

30 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.

31 See Guilkey (1983), et. al.

respect to each business condition variable to differ at different values of the variable. 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.

The general form of the total cost function used in our study is captured by the following formula:

$$\begin{aligned}\ln C &= \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \alpha_j \ln W_j + \sum_\ell \alpha_\ell \ln Z_\ell + \alpha_t T \\ &+ \frac{1}{2}\left[\sum_i \sum_m \gamma_{im} \ln Y_i \ln Y_m + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\ &+ \sum_i \sum_j \gamma_{ij} \ln Y_i \ln W_j + \varepsilon.\end{aligned} \qquad [A17]$$

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:

$$\sum_{j=1}^{J} \frac{\partial \ln C}{\partial \ln W_j} = 1 \qquad [A18]$$

$$\sum_{i}^{M} \frac{\partial^2 \ln C}{\partial \ln Y_i \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots,J \qquad [A19]$$

$$\sum_{n=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_j \partial \ln W_n} = 0 \qquad \forall j = 1,\ldots,J \qquad [A20]$$

These conditions were imposed prior to model estimation.

Estimation of the parameters of equation [A17] 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:

$$SC_j = \alpha_j + \sum_i \gamma_{ij} \ln Y_i + \sum_n \gamma_{jn} \ln W_n. \qquad [A21]$$

The parameters in this equation also appear in the cost model. Thus, information about cost shares can be used to sharpen estimates of 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.[32] 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.

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)[33]. 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.[34] Since we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators (MLE).[35] Our estimates thus possess all the highly desirable properties of MLEs.

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[32] The estimation of model parameters in this type of model is sometimes called <u>regression</u>. .

[33] See Zellner, A. (1962)

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

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

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.[36] 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 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 are three output quantity variables in our model: the number of retail customers, the volume of residential and commercial deliveries, and the volume of other deliveries. We expect cost to be higher the higher are the values of each of these workload measures.

Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, 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.

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

## Other Explanatory Variables

Three additional business condition variables are included in the cost model. One is the percentage of distribution main not made of cast iron. This is calculated from American Gas Association data. Cast iron steel 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 a combination of higher maintenance and replacement costs. 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 this 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.

A third additional business condition is a binary variable that equals one if a company serves a densely settled urban core. Gas service is generally more costly in urban cores due in part to the greater difficulty of performing O&M tasks. Accordingly, we expect the parameter of this variable to have a positive sign.

The gas distribution 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, including technological change in the industry.

## Estimation Results

Estimation results for the gas distribution cost model are reported in Table 25. The parameter values for the additional business conditions and for the first order terms of the translogged variables 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 table shades the results for these terms for reader convenience.

The table also reports 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.

Examining the results in Table 25, it can be seen 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 of the translogged variables, cost was found to be higher the higher were the input prices and the two output quantities. At the sample mean, a 1% increase in the number of customers raised cost by 0.65%. A 1% hike in residential and commercial volume raised cost by about 0.13%. A 1% hike in residential and commercial volume raised cost by about 0.10%. The number of customers served was clearly the dominant output-related cost driver.

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 0.562%. This was almost three times the estimated elasticity of the price of labour. This comparison reflects the capital intensiveness of the gas distribution business.

The estimates of the parameters of the other business conditions were also sensible.

- Cost was lower the greater was the percentage of distribution mains not made with cast iron and bare steel.
- Cost was lower the greater were the number of electric customers served.
- Cost was higher for distributors that served a core urban area
- Cost shifted downward over time by 1.1% annually for reasons not otherwise explained in the model.

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 0.983, suggesting that the explanatory power of the model was high.

## 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:

*W*= Index of growth in the prices paid for inputs

*X*= Index of growth in the amounts of inputs used

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

$Y^E$ = (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 an enterprise experiences revenue growth that matches its cost growth as in a competitive industry or a utility industry.

$$\Delta \text{Revenue} = \Delta \text{Cost} \qquad \text{[A22]}$$

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.

$$\Delta \text{Cost} = \Delta W + \Delta X \qquad \text{[A23]}$$

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.

$$\Delta \text{Revenue} = \Delta P + \Delta Y^R \qquad \text{[A24]}$$

The weights for these indexes are the shares of the individual outputs in total revenue. Equations [A22]-[A24] together imply that:

$$\Delta P = \Delta W - (\Delta Y^R - \Delta X)$$

$$= \Delta W - \Delta TFP^R \qquad [A25]$$

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,

$$\Delta P = \Delta GDPIPI + (\Delta W - \Delta GDPIPI) - \Delta TFP^R \qquad [A26]$$

Since GDPIPI is an index of *output* price inflation, it is reasonable to suppose, using the result in [A25], that:

$$\Delta GDPIPI = \Delta W_{Economy} - \Delta TFP_{Economy} \qquad [A27]$$

[A26] and [A27] together imply that:

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

$$= \Delta GDPIPI - [(\Delta W_{Economy} - \Delta W) + (\Delta TFP^R - \Delta TFP_{Economy})] \qquad [A28]$$

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 [A25]. Denny, Fuss, and Waverman (1984) show that the elasticity-weighted output quantity index, $Y^E$, is the proper output quantity index when the goal of productivity research is to measure progress in *cost* efficiency but not in marketing efficiency. We can restate [A24] as

$$\Delta P = \Delta W - [(\Delta Y^E - \Delta X) + (\Delta Y^R - \Delta Y^E)]$$

$$= \Delta W - [\Delta TFP^E + (\Delta Y^R - \Delta Y^E)]. \qquad [A29]$$

It can be seen that we have decomposed $\Delta TFP^{R}$ into the sum of the growth in $\Delta TFP^{E}$ ---a measure of *cost* efficiency progress --- and ($\Delta Y^{R}$-$\Delta Y^{E}$), 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

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

$$= \Delta GDPIPI - [(\Delta W_{Economy} - \Delta W) + (\Delta TFP^{E} - \Delta TFP_{Economy}) + (\Delta Y^{R} - \Delta Y^{E}) . \qquad [A30]$$

## 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 price cap index. The escalation in rates is measured by a price index $(P^R)$ that is a revenue-weighted average of the growth in the individual rate elements. Formally,

$$\Delta P^R = \sum_{\ell} \sum_{i} \frac{R_{i\ell}}{R} \Delta P_{i,\ell} \qquad [A31]$$

where

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

$R =$ total revenue

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

The growth rate formula for the summary PCI is

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

This can be simplified without loss of generality to

$$\begin{aligned}\Delta PCI &= \Delta GDPIPI - [\Delta TFP^{R} + (GDPIPI - \Delta W) + Stretch] \\ &= GDPIPI - \left[\Delta TFP^{R} + A\right]\end{aligned} \qquad [A32]$$

where

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

$$\Delta TFP^R = \Delta Y^R - \Delta X \qquad [A33]$$

$Y^R =$ revenue-weighted output index

$$\Delta Y^R = \sum_{\ell} \sum_{i} \frac{R_{i\ell}}{R} \Delta Y_{i,\ell} \qquad [A34]$$

$Y_{i,\ell} =$ the amount of billing determinant $i$ for service group $\ell$
X = cost-weighted input quantity index
$C_j =$ cost of input group $j$
$X_j =$ quantity of input $j$
$\Delta W =$ input price index weighted by the costs actually incurred

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

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

$$\Delta P^R = \sum_\ell \frac{R_\ell}{R} \Delta PCI_\ell = \Delta PCI \qquad \text{[A35]}$$

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

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

However, this approach ignores differences in the way in which the growth in the output of various service groups affects utility profit.

## Contributions from Cost Theory

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

$$\Delta Y_\ell^R = \sum_i \frac{R_{i\ell}}{R_\ell} \cdot \Delta Y_{i,\ell} \qquad \text{[A36]}$$

[A34] and [A36] imply that the growth rate formula for $Y^R$ can also be written as follows:

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

In words, output growth is a revenue weighted average of growth in the output indexes for the individual service groups.[37]

Let's consider now the effect of growth in the output of each service group $\ell$ 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

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

Totally differentiating each side with respect to time we find that

$$\begin{aligned}
\frac{d \ln C}{dT} = \Delta C &= \frac{1}{C}\left( \sum_{\ell} \sum_{i} \frac{\partial g}{\partial Y_{i,\ell}} \frac{dY_{i\ell}}{dT} + \sum_{j} \frac{\partial g}{\partial Wj} \frac{dW_j}{dT} \right) \\
&= \sum_{\ell} \sum_{i} \frac{\partial g}{\partial Y_{i,\ell}} \frac{Y_{i\ell}}{C} \frac{1}{Y_{i,\ell}} \frac{dY_{i\ell}}{dT} + \sum_{j} \frac{\partial g}{\partial Wj} \frac{W_j}{C} \frac{1}{W_j} \frac{dW_j}{dT} \\
&= \sum_{\ell} \sum_{i} \varepsilon_{i,\ell} \frac{d \ln Y_{i\ell}}{dT} + \sum_{j} \frac{\partial g}{\partial W_j} \frac{Y_i}{C} \frac{d \ln W_j}{dT} \\
& \sum_{\ell} \sum_{i} \varepsilon_{i,\ell} \Delta Y_{i,\ell} + \sum_{j} \frac{\partial g}{\partial W_j} \frac{W_j}{C} \Delta W_j
\end{aligned} \qquad [A37]$$

where $\varepsilon_{i,\ell}$ is the elasticity of cost with respect to a change in the amount of billing determinant *i* of service group $\ell$. 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

$$\frac{\partial g}{\partial W_j} = X_j \qquad [A38]$$

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

Equations [A37] and [A38] imply that

$$\begin{aligned}\Delta C &= \sum_{\ell} \sum_{i} \varepsilon_{i,\ell} \Delta Y_{i\ell} + \sum j \frac{X_j W_j}{C} \Delta W_j \\ &= \sum_{\ell} \sum_{i} \varepsilon_{i,\ell} \Delta Y_{i\ell} + W^* \end{aligned} \qquad [A39]$$

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

$$\Delta X = \Delta C - \Delta W \qquad [A40]$$

Assuming that growth in this input price index is the same as the growth in $W^*$, Equations [A39] and [A40] imply that

$$\Delta X = \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \cdot \Delta Y_{i,\ell} \qquad [A41]$$

From [A34], [A35], and [A41] 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

$$\Delta TFP^R = \sum_{\ell} \frac{R_\ell}{R} \Delta Y_\ell^R - \sum_{\ell} \sum_{i} \varepsilon_{i\ell} \cdot \Delta Y_{i,\ell}$$

The ADJ Factor

With this background, we now consider how to design the price cap indexes for particular service groups. This can be done by establishing X factors for the $PCI_\ell$ growth formulas that differ from the formula for the summary PCI only in featuring a special adjustment term, $ADJ_\ell$, in the X factor that may vary by service group.

The idea behind $ADJ_\ell$ is to reflect the special impact of the service group on $TFP^R$. To do this, it is necessary to effectively replace the $\Delta Y^R$ and $\Delta X$ components of $TFP^R$ with terms that are specific to the service group. On the demand side, this can be accomplished by taking the difference between the (revenue-weighted) output growth of the group and overall output growth.

$$\Delta Y_\ell^R - \Delta Y^R$$

On the cost side, the following term has intuitive appeal

$$\sum_\ell \ \sum_i \ \varepsilon_{i\ell}\Delta Y_{i\ell} - \frac{\sum_i \ \varepsilon_i}{\sum_i \ \varepsilon_{i\ell}} \sum_i \ \varepsilon_{i\ell}\Delta Y_{i\ell}$$

This is the difference between the cost impact of growth in the quantities of *all* services and the hypothetical cost impact that growth of the output of service group $\ell$ *alone* might have if it was the only service offered. The cost impact of growth in the output of service group $\ell$ is scaled up using the elasticity ratio $\frac{\sum_i \ \varepsilon_i}{\sum_i \varepsilon_{i\ell}}$ where the numerator and the denominator are the elasticities of cost with respect to the growth in *all* services and *group* $\ell$ services, respectively.

Note, however, that this term will not achieve consistency with the summary PCI if the current rate design results in a mismatch between the revenue impact of service $\ell$ growth and the cost impact. We thus replace the *elasticity* adjustment with the analogous *revenue* adjustment R/R$\ell$. The proposed formula for each $ADJ_\ell$ is thus

$$ADJ_\ell = \left[\left(\Delta Y_\ell^R - \Delta Y^R\right) + \left(\sum_i \ \Delta Y^E \varepsilon_i \Delta Y_i - \frac{R}{R_\ell}\sum_i \ \varepsilon_{i\ell}\Delta Y_{i\ell}\right)\right] \qquad \text{[A42]}$$

Equations [A31],[A32],[A35], and [A41] together imply that

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

Thus, the addition of the $ADJ_\ell$ terms 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 [11]? If the marginal cost of each billing determinant *i* is the same for each service group $\ell$

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

then

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

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

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

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

$$= \sum_i \varepsilon_i\Delta Y_{i,}$$

The $ADJ_\ell$ formula then simplifies to

$$ADJ_\ell = \left(\Delta Y_\ell^R - \Delta Y^R\right) + \left(\sum_i \varepsilon_i \Delta Y_i - \frac{R}{R_\ell}\sum_i \varepsilon_{i\ell}\Delta Y_{i\ell}\right) \qquad \text{[A43]}$$

The Y and R terms would all be utility specific. Estimates of the elasticities can be obtained from our econometric cost research. Since

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

it is possible to compute estimates of the elasticities corresponding to individual service groups fairly easily from our estimates of the *overall* elasticities.

## A.8 PEG Qualifications

### A.8.1 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, CA. 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 holds the Jeffrey Miller Chair of Government and the Economy 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 PBR services. Our personnel have over 30 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.8.2 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 PBR 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 PBR plans. He has testified or filed commentary 14 times on statistical benchmarking, and more than 20 times on industry productivity trends and other PBR issues. The venues for this testimony have included California, Hawaii, Kentucky, Maine, Massachusetts, Oklahoma, Ontario, New York, 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 French and 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 PBR.

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 and advanced empirical methods in market 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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