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Ontario Energy Board
EB-2006-0209

Staff Discussion Paper

On an Incentive Regulation Framework for Natural Gas Utilities

January 5, 2007

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EXECUTIVE SUMMARY

The Ontario Energy Board report, *Natural Gas Regulation in Ontario: A Renewed Policy Framework* dated March 30, 2005, outlined the key parameters that need to be addressed in an incentive regulation framework for natural gas utilities in Ontario.

Board staff has undertaken research, commissioned expert advice and consulted with stakeholders on the further development of such a framework.

This discussion paper outlines a potential incentive regulation framework. The key elements of the framework are:

- A price cap mechanism based on the following formula:

  $\%\Delta P = \%\ \Delta GDP\ IPI\ \ FDD - (X + DU) + Z + Y$

  where:
  - ΔP is the annual percentage change in price;
  - ΔGDP IPI FDD is the percentage change in the actual Canada GDP IPI for final domestic demand;
  - X includes the implicit input price differential, productivity differential, and stretch factor;
  - DU is the declining average usage factor (which is separate from the X factor);
  - Z provides for non-routine rate adjustments for events that are beyond the control of the utilities' management; and
  - Y captures routine (or expected) rate adjustments that have been established in the base year;

- A plan term of four or five years (i.e., base year plus 4 or 5 years); and

- Provision for off-ramps.

The services of the consulting firm Pacific Economics Group were retained to support Board staff in this process. Pacific Economics Group is conducting a Total Factor Productivity study and other analyses to be completed in early 2007.

1 INTRODUCTION

This discussion paper sets out Board staff's initial thoughts on an incentive regulation ("IR") framework for Union Gas Limited ("Union"), Enbridge Gas Distribution Inc. ("Enbridge"), and Natural Resource Gas Limited ("NRG"). In developing the concepts set out in this paper Board staff were informed by:

1. The incentive regulation policy described in the Ontario Energy Board's March 30, 2005 report entitled *Natural Gas Regulation in Ontario: A Renewed Policy Framework* (the "NGF Report");

2. The views of stakeholders expressed in consultations with Board staff;

3. Board staff's own research regarding incentive regulation mechanisms adopted and considered in other jurisdictions; and

4. The Pacific Economics Group ("PEG"), Board staff's technical expert.

In the NGF Report, the Ontario Energy Board ("Board" or "OEB") stated that a firm framework would ensure that consistent expectations are held by both utilities and customers. The framework should also meet the following criteria: establish incentives for sustainable efficiency improvements that benefit both customers and shareholders; ensure appropriate quality of service for customers; and create an environment that is conducive to investment, to the benefit of both customers and shareholders. The Board believed that a ratemaking framework that meets these criteria would ensure that the statutory objectives of consumer protection, infrastructure development and financial viability are met, and that rates would be just and reasonable.

The Board, in the NGF Report, addressed the following key parameters for an IR framework:

- Annual adjustment mechanism;
- Rebasing;
- Earnings sharing mechanism;
- The term of the plan;
- Off-ramps, Z factors and deferral or variance accounts;
- Service quality monitoring;
- Financial reporting; and
- Filing guidelines.

The Board, in the NGF Report, stated that an earning sharing mechanism ("ESM") should not form part of the IR plan. The Board believed that an ESM would reduce the utility's efficiency incentives.

The Board subsequently dealt with some of these parameters as follows:

- The Board undertook a consultation to amend the Gas Distribution Access Rule ("GDAR") to establish a service quality framework (standards and reporting requirements) for the natural gas utilities.

- The Board established 2007 as the test year to be used to set base year rates for Union and Enbridge. At this time, base year rates have been set for Union, and Enbridge's 2007 rate case proceeding is currently underway. With regard to NRG, the Board has stated that it will have another cost-of-service application in fiscal year 2008.

- The Board issued Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications to be used for setting the 2007 base year rates.

This discussion paper addresses the remainder of the parameters listed above. With the benefit of stakeholder consultation, this paper has been produced to share Board staff's current thinking on an incentive regulation framework.

1.1 Structure of the Discussion Paper

This discussion paper is organized as follows. Section 2 describes Board staff's view on the underlying principles of an IR plan while sections 3 and 4 address the IR plan design and other issues respectively.

1.2 Process and Stakeholder Meetings

Board staff focused its research, commissioned expert advice and consulted with stakeholders on the following parameters:

- The annual adjustment mechanism (i.e. inflation factor, and X factor including a stretch factor);
- The term of the IR plan;
- Routine and non-routine adjustments;
- The need for off-ramps;
- The reporting requirements that will apply during the term of the IR plan;
- Rebasing requirements;
- The treatment of demand side management ("DSM"); and
- The need for any other adjustments.

Starting in October 2006, Board staff held a number of meetings with stakeholders (listed in Appendix 1). At these meetings, Board staff outlined a list of key elements in an IR plan based on the above listed parameters to initiate discussion on the IR framework. Stakeholders were asked to review the list to confirm accuracy and completeness. Based on these stakeholder discussions, Board staff revised the list. On November 2-3, 2006, an all stakeholder meeting was held where stakeholders, Board staff and the Board's technical expert presented material. This meeting assisted Board staff in formulating the key elements of an IR plan. Then, at the November 24th stakeholder meeting, Board staff presented its current thinking on the generic IR framework for natural gas utilities. All material related to these consultations are available on the Board's website.

2 UNDERLYING PRINCIPLES

The Board's ultimate responsibility is to set rates that are just and reasonable. It has been left to the discretion of the Board to select, amongst available approaches, the rate-setting methodology that is optimally suited to achieving that end and to the Board's guiding objectives as set out in section 2 of the *Ontario Energy Board Act, 1998*.

In the NGF Report, the Board stated that an effective ratemaking framework must meet the following criteria:

- establish incentives for sustainable efficiency improvements that benefit both customers and shareholders;
- establish appropriate quality of service for customers; and
- create an environment that is conducive to investment to the benefit of both customers and shareholders.

Building upon this foundation, Board staff believes that the Board's statutory responsibility is best fulfilled, and its statutory objectives in relation to natural gas are best promoted, using a rate-setting methodology that is designed on the basis of the following principles:

1. **Storage, transmission and distribution rates should be predictable and stable.** This should provide an environment where utilities and consumers are better able to plan and make decisions.

2. **The rate adjustment mechanism should be clear.** The mechanism should be clearly articulated and not be subject to multiple interpretations by stakeholders.

3. **The pursuit of efficiency should be encouraged.** The plan should encourage greater economic efficiency by providing incentives for the implementation of sustainable operational efficiency improvements. The benefits of these efficiency improvements should be shared by customers and shareholders.

4. **Utilities should be encouraged to continue infrastructure investment to maintain safety and reliability.** The plan should encourage investment of funds to maintain safety and reliability of gas delivery.

5. **Customer service standards should be maintained.** Appropriate service quality standards are the cornerstone of consumer protection. A service quality framework should include performance standards, reporting requirements, and compliance measures to ensure customer service standards are maintained.

6. **DSM activities should be encouraged.** The IR framework and the conservation and demand management policies should be compatible.

7. **A balance between the financial viability of the utilities and the interests of natural gas consumers should be maintained.** A financially viable natural gas distribution sector will help to sustain a robust natural gas market in Ontario, which will benefit consumers in terms of price, reliability and safety.

8. **System expansion into new communities should be facilitated.** Not all parts of Ontario have access to natural gas service. The plan should ensure that where extension of such service is economically viable, the utility has a reasonable opportunity to earn a return on its investment in a timely manner.

In addition, the rate-setting methodology should be capable of implementation through a regulatory process that is efficient while at the same time addressing the concerns of interested parties and ensuring openness and transparency. The costs of administering the plan, including the costs imposed on all participants, should not exceed the benefits to be derived from the plan.

At the stakeholder meetings, stakeholders generally agreed with the above principles. One stakeholder proposed that financial viability of the industry needed to be included, and has been reflected above.

Other stakeholders suggested as a further principle that ratepayers be better off, or at least not worse off, in real terms, in moving from cost-of-service (“COS”) regulation to IR (in terms of rates, service quality and financial soundness). Board staff believes that this is an underlying assumption of the IR plan.

3 INCENTIVE REGULATION PLAN DESIGN

3.1 Price and Revenue Caps

Price and revenue caps are common types of incentive regulation mechanisms. Under these mechanisms, prices or revenues are set independent of costs for some years. During this period, the utility can increase its profitability by improving performance. Thus, price and revenue cap mechanisms generate incentives for cost containment and other operational efficiencies.

3.1.1 Price Cap

A price cap plan sets the maximum rate escalation that the utility is allowed. It is called a cap because the utilities usually have the flexibility to charge rates that are less than the maximum allowed. Price cap index ("PCI") formulas vary from plan to plan but have the following general structure. The PCI growth rate is the difference between the growth in an inflation measure ("P") less an X factor, plus or minus non-routine adjustments due to extraordinary events ("Z"), as depicted in the following formula:

$$\boxed{growth\ PCI = growthP - X \pm Z}$$

3.1.2 Revenue Cap

A revenue cap limits the escalation in revenue that the utility is allowed. The revenue requirement in a year is set according to the previous year's revenue requirement indexed by an inflation factor and adjusted for an X factor, output growth and non-routine adjustments due to extraordinary events. A balancing account mechanism is established to capture the difference between actual revenue and the approved revenue requirement.

A revenue cap index ("RCI") typically has the following general form:

$$\boxed{growth\ RCI = growthP - X + growthO \pm Z}$$

Where "O" is a measure of output growth.

3.1.3 Comparison

Revenue caps differ from price caps in reducing both the incentive and risk to the utility associated with demand fluctuations. Under a revenue cap, the difference between actual revenue and the approved revenue requirement is captured in a balancing account, and the ratepayer is at risk for this balance. Therefore, utilities may be less aggressive in promoting customer attachments and throughput growth. Similarly, utilities will be protected in cases where they experience decline in throughput without corresponding decrease in costs.

Since prices (not quantities) are constrained under a price cap, revenue caps can be more compatible with energy efficiency programs. However, the design of a price cap can be adapted to meet energy efficiency objectives. For example, some price cap plans treat expenditures associated with energy efficiency programs as a rate adjustment. In contrast, under revenue caps, rates will automatically be adjusted to reflect the declining average usage in customer demands.

Price caps generally result in rates that are more stable and predictable than a revenue cap mechanism. This is a result of the balancing account under a revenue cap. Additionally, revenue caps typically do not specify how revenue growth would be reflected in rates.

Revenue caps have been used in circumstances where utilities have been exposed to declining average use per customer because they can provide automatic compensation. Under a revenue cap, the compensation is proportional to the declining average use that actually occurs during the term of the plan. The X factor can then be designed solely to reflect cost efficiency trends. Under a price cap, rate relief for declining average use per customer is accounted for in the X factor, or alternatively can be dealt with through a separate rate adjustment. In either case, the compensation is generally fixed for the term of the plan and is based on historical trends.

Regulatory cost can be greater under a revenue cap. This is due in part to the potential controversy in the design of the output growth factor in the revenue cap index formula. Additionally, there might be a continued need to consider the allocation of the revenue requirement amongst service offerings, customer rate classes, and rate design matters.

While Board staff sees merits to a revenue cap approach, Board staff is of the view that a price cap better reflects the principles of rate stability and predictability and economic efficiency, as well as allowing for a more efficient regulatory process.

3.2 Inflation Factor

The inflation factor represents the change in the cost of the inputs purchased by the gas utilities.

Figure 1 outlines the different options for an inflation measure.

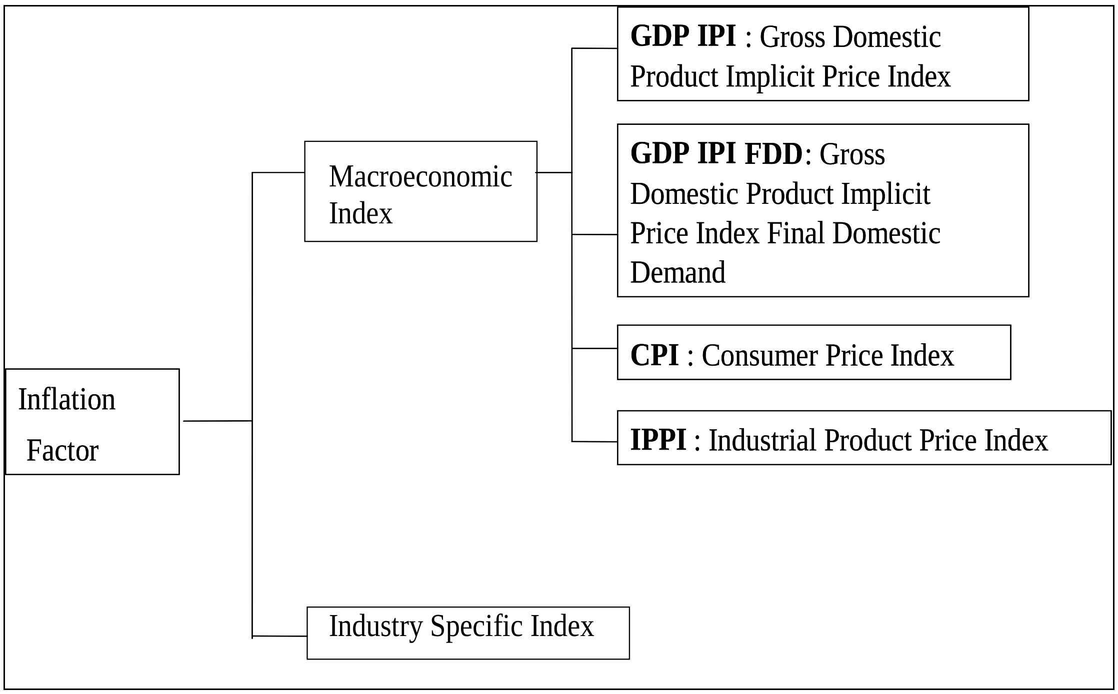

Figure 1: Inflation Factor Options

Board staff is of the view that the following criteria should be considered in selecting an appropriate index:

- Coverage: the index should accurately capture the likely change in the utilities' costs during the term of the IR plan;
- Simplicity: the index should be simple enough to be understood by rate payers. Complex calculations for the index estimation should be avoided;
- Credibility: the index must originate from a credible source or should be calculated on the basis of a robust study;
- Availability: the index should be available on a timely basis for the implementation of rates each year; and
- Stability: volatile indices should be avoided since one of the principles underlying the plan is that rates should be stable and predictable.

3.2.1 Industry Specific or Macroeconomic

Macroeconomic measures (outlined in Figure 1) track growth in the prices of a wide range of goods and services. They have been used extensively in IR plans in North America and around the world because they are readily available and generally published by a trusted source. Statistics Canada ("Stats Canada") publishes actual values of these measures. Forecast values of some of these measures are available from banks and forecasting companies. Also, macroeconomic indices are more easily understood by the public than industry-specific measures.

Macroeconomic indices are economy-wide measures and therefore they do not track industry specific input price variations. In contrast, an industry-specific input price index (IPI) would be designed and calculated to specifically track the inflation of capital, labour and materials for natural gas utilities. The Board applied an IPI in its first generation incentive mechanism for electricity distributors. In the case of Union's and Enbridge's trial performance based regulation plans, the Board applied macroeconomic indices.

Board staff is of the view that an IPI would be more difficult to implement than a macroeconomic index because its design can be subject to controversy and its results tend to be very volatile if not smoothed.[1] Controversy can also arise over the best smoothing mechanism.

Therefore, Board staff sees the merit in using a macroeconomic index as the inflation factor with the caveat that the X factor would be adjusted to include an input price differential and a productivity differential. A detailed explanation of the input price and productivity differentials is outlined below in the X Factor section.

3.2.2 Macroeconomic index

Union and Enbridge indicated their preference for using an annual forecast of CPI as the inflation measure. The reasons outlined were: CPI is better understood than GDP IPI by ratepayers and CPI forecasts are available from consensus forecasts and a number of other sources.

Board staff reviewed the different macroeconomic price indices in terms of the criteria of coverage, simplicity, availability, stability and credibility. Table 1 highlights the advantages and disadvantages of each of these indices.[2]

[1] See PEG's presentation dated November 2-3, 2006 available from the OEB website
[2] A detailed explanation of the advantages and disadvantages of each index was presented at the stakeholder meeting on November 10, 2006. This presentation is available from the OEB website

Table 1: Index Comparison

Criteria	GDP IPI FDD	GDP IPI	CPI	IPPI
Coverage	✓ Broad coverage of goods and services relevant to the gas industry (capital, labour, materials)	✓ Broad coverage of goods and services relevant to the gas industry (capital, labour, materials)	× Limited coverage of goods and services relevant to the gas industry	× Limited coverage of goods and services relevant to the gas industry
Simplicity	× Lower customer familiarity than CPI ✓ Facilitates the calculation of input price and productivity differentials used in X factor calibration	× Lower customer familiarity than CPI ✓ Facilitates calculation of X factor, since the TFP trend of the economy corresponds to GDP IPI	✓ Customer familiarity × Does not facilitate calculation of X factor	× Lower customer familiarity than CPI × Does not facilitate calculation of X factor
Availability	✓ Published annually for Canada and Ontario and quarterly for Canada × Subject to future revisions	✓ Published annually for Canada and Ontario and quarterly for Canada × Subject to future revisions	✓ Published monthly ✓ Subject to fewer and minor future revisions	✓ Published monthly × Subject to future revisions
Stability	✓ Less volatile due to the exclusion of petroleum products, gas exports, and other price-volatile exports	× More volatile than GDP IPI FDD	× More volatile than GDP IPI FDD	× Very volatile
Credibility	× Very few forecasts available. None are publicly available	× Few forecasts available; not in consensus forecast. Some are publicly available	✓ Forecasts widely available from consensus, banks, public institutions	✓ Forecasts published by consensus. Few publicly available forecasts

The above assessment, which attributes equal weight to each of the five criteria, ranks the GDP IPI FDD and the CPI equally. Board staff however thinks that the GDP IPI FDD should be used as the inflation factor in the IR plan. Board staff recognizes that GDP IPI FDD could be more difficult to explain to ratepayers than CPI. However, Board staff's view is that this potential complexity is offset by the advantages of GDP IPI FDD in terms of coverage, volatility and the simplicity it brings to the calculation/calibration of the X factor.

3.2.3 Implementation Details

Board staff also examined the availability of a provincial and federal version of the GDP IPI FDD, and whether this index should be fixed or variable during the plan term. In addition, Board staff researched whether the index should be an actual or a forecast value.

<u>Canada or Ontario GDP IPI FDD</u>

GDP IPI FDD is published for Ontario and Canada. Board staff notes that the differences between the federal and provincial indices are minor.

GDP IPI FDD Ontario is published annually in April of the following year. The federal version is published annually in February of the following year and also quarterly. Since a rate order needs to be in place by December 15th (for Union and Enbridge in order to implement rates effective January 1st), the inflation adjustment would have a two year lag if an annual index were used.

To avoid this time lag so that rates reflect the most recent inflation trend, Board staff sees the benefit of using the quarterly GDP IPI FDD Canada index. Specifically, a simple average of the annualized changes of the last four quarters should be used.

Union raised concerns over Stats Canada's revisions to the GDP IPI FDD. Board staff understands that published statistical data may be subject to revision by Stats Canada. However, Board staff shares the view of another stakeholder who commented that using an annualized approach (i.e., average of the annual changes for the last four quarters) minimizes the impact of the revisions in a particular quarter. It should be noted that the annual change in GDP IPI FDD published by Stats Canada is also calculated using this methodology.

Moreover, in the 2000-2003 revisions to the Income and Expenditure Accounts, Stats Canada acknowledged that "in general, price indexes at the most detailed level employed in the deflation of GDP were unrevised".[3] Board staff believes that the use of the GDP IPI FDD (which excludes exports) will reduce a source of revisions, especially those related to changes in the exchange rate.

Fixed or variable

In its July 21, 2001 Decision with Reasons in proceeding RP-1999-0017, the Board rejected a fixed inflation factor for Union's PBR plan because a fixed inflation factor would unnecessarily increase the risk exposure for all parties.

On that basis, the inflation factor should be adjusted every year to take into account the most recent inflation trend.

Forecast or actual value

Enbridge and Union expressed concern over the use of an actual value as a proxy for future inflation rather than a forecast value. They also indicated that they did not see the merit of having a "true up" mechanism to reflect actual inflation, as an adjustment after-the-fact serves little purpose.

Board staff is not convinced that a forecast value should be used for two reasons. First, there are very few forecasts available of GDP IPI FDD and the forecaster with the best performance[4] does not publish GDP IPI FDD forecasts. Therefore, the opportunity to mitigate the risk of forecasting errors is minimal. Second, Board staff believes that with relatively stable inflation levels (as the ones seen in the last 15 years), the inflation of a previous year is a reasonable proxy of inflation in the following year. As illustrated in Table 2 on the next page, over the last five years, the cumulative error of GDP IPI FDD Canada (measured as the difference between actual and the lagged GDP IPI FDD) is lower than the cumulative error of the CPI forecast.

[3] Statistics Canada Catalogue No 13-010-XIE, p 29
[4] As identified by the Campbell and Murphy study on "The Recent Performance of the Canadian Forecasting Industry" published in Canadian Public Policy, Vol XXII, no 1 2006

Table 2

Year	GDP IPI FDD CAN Actual	GDP IPI FDD CAN Year ending June of Previous Year (1)	Difference GDP IPI FDD Actual vs Previous Year	CPI CAN Actual	CPI CAN Forecast (2)	Difference CPI Actual vs Forecast
2001	1.7	1.8	-0.1	2.5	2.4	0.1
2002	2.3	2.3	0.0	2.2	1.6	0.6
2003	1.4	1.7	-0.3	2.8	2.4	0.4
2004	1.7	2.3	-0.6	1.8	1.6	0.2
2005	1.8	1.2	0.6	2.2	1.9	0.3
Cumulative Error in 5 years			**-0.3**			**1.7**

(1) Calculated as the simple average of the four annualized changes in the quarterly GDP IPI FDD index from Stats Canada.
(2) Data from consensus forecast: average of 16 forecasts issued in December of the previous year.

3.3 X Factor[5]

Index research is widely used in North American regulation to design rate escalation mechanisms. A key result of the research is that the trend in the prices charged by an industry that earns, in the long run, a competitive rate of return is equal to the industry's unit cost trend. This trend is, in turn, equal to the difference between an industry's input price and total factor productivity ("TFP") trends. The growth rate formula for a price cap index can thus include the difference between an input price index for the industry and an X factor that is calibrated so that the price cap index tracks the unit cost trend of the industry. This approach to X factor design was used by the Board in its first incentive regulation regime for electricity distributors.

The term "calibration" is employed because a stretch factor is commonly added to the X factor to share with customers the expected benefits of improved performance that are occasioned by the move from COS to incentive regulation. The stretch factor will be higher the greater the expected performance improvement.

The standard formula for index-based X factor design is different when an index such as GDP IPI is used as the inflation measure in the price cap index escalation formula. As a measure of inflation in the prices of consumer products and other final goods and services, GDP IPI is a measure of output price inflation. As such, it already reflects the input price and productivity trends of the economy, much as an index of inflation in the rates charged by a group of power distributors would reflect their input price and productivity trends. Apart from the stretch factor, an X factor is therefore needed in a price cap index driven by GDP IPI growth only to reflect the difference between the input price and productivity trends of the industry and the economy.

The growth in a TFP trend index is the difference between the trends in summary output and input quantity indexes. The growth in the summary output quantity index is a weighted average of the growth in subindexes that represent various output dimensions (e.g., the number of customers served and throughput). In a TFP index that conforms to the index logic conventionally used in price cap index design, the weights are the shares of billing determinants in the utility's total revenue. These weights reflect the impact of output growth on revenue and not on cost.

Rates for energy distribution services commonly feature customer charges (sometimes called access) and either volumetric charges or demand charges. Rate designs frequently do not reflect the drivers of distribution costs well. For example, distribution costs are commonly driven chiefly by customer growth, whereas distribution revenues are commonly driven chiefly by delivery volumes

[5] This section was written by Board staff's technical expert from PEG

and contract demand. Under these circumstances, a TFP index calculated in the conventional manner using revenue shares will be sensitive to trends in average use, and will differ from a TFP index designed to measure only cost efficiency trends. 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 many gas utilities today. Contributing factors include high gas prices and improvements in the efficiency of gas-fired equipment.

During the consultation process, stakeholders provided several comments that have a bearing on the design of X factors for Ontario gas utilities:

1. Enbridge and Union expressed concern that the rate escalation mechanism should provide needed rate relief for declining average use per customer trend in the province by some means.

2. Other stakeholders voiced concern about a productivity differential that is sensitive to declining average use per customer trends. Stated reasons included:
   - a desire to understand the separate impacts on TFP of improved cost efficiency and declining average use per customer trends; and
   - a concern that the declining average use per customer trend should affect only rates for residential, commercial, and other customers with weather-sensitive demand.

3. Enbridge expressed concern that the price cap index may not allow enough price escalation to fund needed main replacement programs and system expansions. Absent such funding, Enbridge requested that funding for main replacement programs and system expansions be dealt with through a cost pass-through.

4. Some parties expressed an interest in investigating whether a separate X factor for transmission services would be warranted.

3.3.1 Overview of the Research

Board staff has retained PEG to undertake input price and productivity research in support of X factor design. PEG will work with participating Ontario utilities to develop the data needed to measure their recent historical input price, output price (i.e. rate) and productivity trends. A sample period of at least ten years ending in 2005 is desirable for this research.

The study will also consider the input price and productivity trends of a sample of 38 U.S. gas utilities. These trends will be calculated from a sample of U.S. data of a period of more than ten years gathered by PEG.

If the data obtained from Ontario gas utilities are satisfactory, PEG expects that the productivity differentials that are used in X factor design will be based at least partly on Ontario experience. The productivity trends of U.S. distributors may also be used to calculate the productivity differentials, in addition to serving as a "reality check" for the Ontario results.

The proposed X factor is the sum of three 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 economy and the industry; and
- Stretch Factor.

Each of these terms is described below.

3.3.2 Calculating the Input Price Differential

PEG will compute an IPD by comparing the input price trend of Ontario gas utilities to the input price trend of the Canadian economy. The input price trend of the utilities will be computed as a cost-weighted average of the growth in subindexes representing trends in the prices of 3 input groups: labour, materials & services, and capital. Cost weightings capture the impact of input price growth on cost. Cost weights will be based on the shares of the input groupings in the total costs of the Ontario gas utilities. The input price subindexes will be drawn chiefly from Stats Canada data. In conformance with the index logic discussed above, the input price trend of the Canadian economy will be calculated as the sum of the trend in GDP IPI FDD and one of Stats Canada's multifactor productivity indexes for Canada's private business sector.

3.3.3 Calculating the Productivity Differential

The TFP growth of the Ontario and U.S. gas utilities will be decomposed into two terms: the growth in their cost efficiency and a term that captures the effect of average use trends on TFP. The growth in cost efficiency will be measured with a TFP index that features an output quantity index based on cost elasticity weights rather than revenue weights. This decomposition is well established in literature.

Cost elasticities are measures of the cost impact of business condition variables. The elasticity of cost with respect to the number of customers, for instance, is the percentage change in cost that results from a one percentage change in customers. The output quantity subindexes will include the number of customers and one or more measures of throughput.

The cost elasticity estimates will be based on original econometric research conducted by PEG on the impact of output and other business conditions on the historical costs of gas utilities. The sample for this research will include U.S. data and may also include Ontario data. PEG has undertaken several econometric studies of gas distribution costs and has used the elasticity estimates in its productivity research on several occasions.

PEG will calculate the PD by comparing the productivity trends of the gas utility industry and the Canadian economy. The productivity trend of the economy will be measured using one of Stats Canada's multifactor productivity indexes for Canada's private business sector. The productivity trend of the industry will be measured using the elasticity-weighted output quantity indexes that are designed to measure trends in cost efficiency.

3.3.4 Stretch Factor

With regard to the stretch factor, the following considerations suggest that the move from COS to IR will bolster incentive power substantially:

- The utilities have come in for rate cases frequently in recent years. Enbridge, for example, has filed rate cases annually for several years.
- The proposed plan term is four or five years.
- The plan does not contain an earnings sharing mechanism.

Therefore PEG anticipates that the plan should involve a material strengthening of performance incentives.

3.4 Single or Multiple Price Caps

A single price cap for all customer rate classes is a common feature in IR plans. However, Board staff recognizes that there could be circumstances that would warrant a differentiated X factor or a separate rate adjustment for the different lines of business (e.g., distribution, storage, and transmission) or by customer rate class. For example, declining average use could affect rate classes differently and may justify a differentiated X factor or separate rate adjustment for each rate class.

Taking into consideration these situations, Board staff sought stakeholder views on the appropriateness of each of the following variations: a single price cap for all customers; a different price cap for each of the utility's lines of business; and a different price cap for each customer rate class.

One stakeholder expressed the view that Union's transmission and distribution / storage capital expenditures profiles might be different. Therefore, it might be necessary to examine the costs underpinning these functions to determine if these services should have a different X factor.

Board staff's view is that the productivity performance of each function performed by the utilities could differ significantly due to differences in technology, capital expenditures or the potential for cost reductions. Absent any empirical information, Board staff asked PEG to undertake further analysis to determine whether a different X factor for Union's transmission services is required and feasible given the available data.

PEG's preliminary assessment is that there is a lack of available data to properly conduct this type of study. Further, distribution rates for Union's small volume consumers bundle transmission and distribution services. Therefore Board staff does not consider that this issue should be further pursued at this time.

Union and Enbridge raised the issue of declining average use in the context of an IR plan. They explained that the decline in average use is attributable to several factors including: more efficient gas appliances; better home insulation; and customer response to higher natural gas prices. They also pointed out that they have been compensated for declining average use under COS regulation.

Some parties suggested that if the effect of declining average use is included in the IR plan (either in the X factor or as a separate factor), then having a different price cap for each rate class may be justified. In their view, declining average use may affect customer rate classes differently, and inter-class cross subsidization should be minimized.

Board staff recognizes that declining average use is being experienced by many gas utilities in North America. This trend has financial implications for the gas utilities that "increase the need for rate escalation".[6] As a result, a number of gas utilities in North America have rate mechanisms that separate or decouple the recovery of fixed system costs from the volume of gas delivered to customers or use novel rate methodologies to stabilize earnings or revenue flow.[7]

Therefore, Board staff sees merit in investigating this issue further. PEG will undertake analysis to determine the extent of declining average use, and whether it differs materially among rate classes. PEG advised Board staff that the declining average use factor ("DU factor") could take the form of the difference between the recent historical trends in industry output quantity indexes that are measured using revenue and cost elasticity weights. This approach would effectively ensure that the overall growth in the rates charged by Ontario gas utilities be is limited by the growth in TFP index based on revenue-share

[6] Lowry, Getachew and Fenrick (2006): "Regulation of Gas Distributors with Declining Use per Customer", Dialogue, Vol. 14 No. 2
[7] Ryan K: "Exploring the Philosophy of Rate Design" in American Gas, November 2006

weights. PEG will also undertake analysis to determine whether the declining average use factor should be fixed or variable throughout the plan term.

Board staff agrees with stakeholders that different adjustments by rate class would be warranted if the reduction in average use varies significantly by customer group. Board staff also thinks that any adjustment that may be warranted should take the form of a factor separate from the X factor.

3.5 Rate Design

Union and Enbridge have indicated a preference for rate re-design flexibility during the term of the plan. For example, they would like the ability to re-balance the recovery of fixed costs through fixed charges and variable charges while being revenue neutral at the rate class level. Also, Union and Enbridge may require modifications to their rate schedules for services to gas-fired power generators.

Other stakeholders suggested that allowing rate re-design during the IR plan term would not result in rate predictability and stability. Stakeholders felt that if a declining average use factor was incorporated into the price cap there would be no need to re-design rates for this purpose.

Board staff has two concerns over rate re-design during the term of the plan.

First, Board staff believes that the price cap should be applied equally to the fixed and variable charges at the rate class level to maintain the current fixed/variable ratio. Staff considers that different percentage changes to the fixed and variable charges (even though revenue neutral at the rate class level) could result in large rate increases for some customers within a given rate class. For example, increases in the monthly customer charge will benefit larger customers to the detriment of low volume users. Therefore, Board staff agrees that rate re-design during the plan term would be contrary to the principle of rate predictability and stability.

Second, if the declining average use is recognized in the price cap, this should alleviate some of the concerns that Union and Enbridge have expressed regarding their exposure to declining average use.

Despite these concerns, Board staff recognizes that there could be changes in the marketplace during the term of the plan. For example, changes to gas-fired power generator services and/or changes in market conditions that lead to inappropriate customer behaviour could prompt the utilities to propose changes to their respective rate schedules.

Board staff believes that rate re-design should be addressed at rebasing. However, as previously mentioned, if material changes in the marketplace occur that would warrant amendments to existing rate schedules (including terms and conditions of service), the utilities should have the opportunity to apply for rate re-design during the plan term. The onus would be on the utilities to fully justify their application. This process is discussed below in the Rate Setting Filings section.

3.6 Routine and Non-Routine Adjustments

Routine and non-routine adjustments are treated as separate rate adjustments in the price cap index formula.

3.6.1 The Z factor

A Z factor provides for non-routine rate adjustments intended to safeguard customers and the gas utility against unexpected events that are outside of management's control. Examples include changes in tax rules[8] and natural disasters.

Enbridge and Union suggested that the Board adopt high-level criteria for allowing certain costs to be recovered such as changes mandated by legislation at all levels, changes in Generally Accepted Accounting Principles ("GAAP") and changes in regulatory rules. Other parties advocated the need for a more detailed set of criteria that would limit Z factors. Also, many stakeholders suggested that non-routine adjustments should be symmetrical and therefore not be limited to cost increases only. Furthermore, these stakeholders proposed that the onus be on the gas utilities to bring forward Z factors that may increase or decrease the prices ultimately paid by ratepayers.

In assessing the need to establish a criteria set, Board staff relied on the conclusions outlined in the NGF report. As a result, Z factors should be limited to well-defined and well-justified cases only. Board staff agrees that the Z factor adjustment should be symmetrical (i.e., positive or negative amounts) and that the onus should be on the gas utilities to bring forward Z factor events.

[8] It should be noted that changes to federal tax laws would already be incorporated into the inflation factor (GDP IPI FDD)

In order for amounts to be considered for recovery as a Z factor, staff is of the view that the amounts should satisfy all four criteria set out in Table 3 below.

Table 3: Z factor Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to operational requirements created by the Z factor event. A significant portion of the expenditure should be demonstrably linked to addressing new operational requirements, as opposed to upgrading current procedures and systems to gain efficiencies under the guise of addressing the event. At least 75% of the amount should be directly and demonstrably linked to the Z factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amount must have a significant influence on the operation of the gas utility; otherwise it should be expensed in the normal course and addressed through organizational productivity improvements. Board staff recommends that the threshold amount be $1.0 million* for individual items.
Inability of Management to Control	To qualify for Z factor treatment, the amount must be attributable to some event outside of management's control (i.e., the event causing the amount must be exogenous to the utility).
Prudence	The amount must have been prudently incurred.

* This materiality threshold would be applicable to Union and Enbridge. An appropriate amount would need to be determined for NRG.

The above criteria set is consistent with the Board's previous findings in its July 21, 2001 Decision with Reasons in proceeding RP-1999-0017 (comprehensive PBR plan for Union Gas).

3.6.2 The Y factor

A Y factor captures routine (or expected) rate adjustments. Examples of these pass-through adjustments include variances in upstream costs such as gas supply, transportation and balancing expenses, and DSM costs.

Board staff thinks that these expected pass-through adjustments should be limited to the variance and deferral accounts established in the utility's base year rate case. Therefore, during the plan term, there would be no additions to the accounts established in the base year unless an account is established in another Board proceeding. For example, the deferral and variance accounts established in the Settlement Agreement and the November 7, 2006 Decision with Reasons in the NGEIR and Storage proceeding (EB-2005-0551) need to be included.

During the Storage and NGEIR proceeding, Union proposed to eliminate three transactional transportation deferral accounts (179-69, 179-73, and 179-74) effective January 1, 2007. In its Decision with Reasons, the Board stated that this proposal should be considered as part of the development of the IR mechanism.

Board staff agrees with Union that these three transmission-related deferral accounts should be eliminated. Since Transactional Transportation Services are part of the gas utility's monopoly service, the Transactional Transportation Services revenue should not be treated any differently, from a ratemaking perspective, than any other regulated revenue. In addition, Union stated that the revenue derived from these services can be forecasted as accurately as any other revenue. Under the current regulatory regime, forecast revenue act as an offset to the revenue requirement, and there are no variance accounts to capture variances relative to forecast. The utilities thus bear the risk of any under earnings, and can reap the benefits of over earnings. This treatment is also consistent with the Board's view that "an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variances accounts".[9]

3.7 Miscellaneous Non-Energy Services

Miscellaneous non-energy services pertain to services such as meter unlocks and removal, administration fees for returned cheques, etc. A detailed list of these services and associated charges for both Enbridge and Union are found in Appendix 2.

During the consultation process, Enbridge and Union questioned whether the Board regulates these services. In response to this issue, Board staff notes that in its November 7, 2003 Decision with Reasons in proceeding RP-2002-0133, the Board found that the term "rate" as defined in section 3 of the *Ontario Energy Board Act, 1998* was sufficiently broad to include service charges levied by a distributor. Consequently, the Board found that approval of service charges was within its jurisdiction. The Board noted that this interpretation was consistent with how the Board had been regulating service charges for Union and electricity distributors. In proceeding RP-1999-0017, the Board ordered that Union file its "miscellaneous" charges as part of its rate order and file supporting cost data for any changes to the charges. In electricity, the Board approves "specific service charges" as a part of its rate review process for electricity distributors, and guidance in this regard is set out in the Electricity Distribution Rate Handbook.

In Enbridge's 2003 rate case, the Board approved the list of service charges and directed that Enbridge include the schedule of such charges in its rate order.

[9] NGF Report, at page 31

That schedule was subsequently filed as Rider "G" and has been included in the utility's rate handbook in each rate application, including Quarterly Rate Adjustment Mechanisms ("QRAMs").

Enbridge and Union proposed that the miscellaneous non-energy service charges should be outside of the price cap mechanism. They raised the concern that many of these charges are third-party charges and, as a result, the utilities would like the opportunity to apply for changes to these charges during the plan term. Other parties suggested that these charges should remain unchanged during the plan term and that all changes should be dealt with at the time of rebasing.

Board staff thinks that the miscellaneous non-energy charges should be outside of the price cap and generally remain unchanged during the plan term. Board staff believes that the onus should be on the utilities to provide evidence that supports a change to the charges during the plan term.

3.8 Term of the Plan

Most of the consumer groups indicated a preference for a shorter term plan while other stakeholders favoured a longer term plan.

In the NGF Report, the Board stated that three years represents the minimum term that may be expected to give rise to productivity incentives, and expressed a preference for a plan term of five years. Therefore, Board staff thinks a plan term of four or five years (i.e., base year plus 4 or 5 years) will allow the utilities to have greater opportunities to implement sustainable efficiency improvements that benefit customers and shareholders.

During the consultation process, stakeholders raised the concern that the COS rebasing would be resource intensive and that Board staff should consider staggering the applications. Board staff is of the view that Enbridge and Union should start their IR plans on January 1, 2008 but have different plan terms. This would mean that one of the utilities would have a plan term of four years while the other would have a plan term of five years. Board staff recognizes that the utilities might not have the same opportunities to implement sustainable efficiency improvements, and therefore the utility with the shorter term plan should have a lower stretch factor.

While Board staff considers that the commencement date and four or five-year term noted above would be suitable for Union and Enbridge, Board staff also considers that the commencement date and plan term for NRG should be determined by the Board following further examination of NRG's changing customer base. The upcoming generic hearing to establish the elements of the IR plan could be an appropriate forum for that examination.

3.9 Off-Ramps

An off-ramp is a pre-defined set of conditions under which the IR plan would be terminated or modified before its end date, usually because of some unforeseen event.

Some consumer groups raised concerns regarding the absence of an ESM in the IR plan. Some stakeholders suggested that a deadband be established around the return on equity ("ROE") to account for over earnings, while others thought that an off-ramp should apply to both over and under earnings. An ROE outside of the deadband would trigger an off-ramp.

Enbridge and Union were of the view that off-ramps for under earnings are not necessary since they could apply to the Board if conditions were such that the continued use of the IR mechanism would threaten their financial viability. They also stated that it would be difficult to quantify at the outset the basis point spread that would threaten their financial viability since the financial markets determine their credit ratings.

Board staff agrees that if a utility were to experience a sustained financial decline, then the IR plan may need to be re-examined by the Board. Also, Board staff is of the view that achieving sustained "supernormal profits" would be an indication that the IR plan may need to be reviewed.

To address stakeholder concerns, Board staff reviewed historical normalized ROE to determine an appropriate reference point for an over earnings parameter to be used as an off-ramp. Over the last 20 years, Enbridge has achieved actual normalized ROEs as high as 345 basis points above its approved ROE. [10] Union has achieved 240 basis points above its approved ROE during the period 1990-2002.[11] Board staff believes that an IR plan should provide an appropriate balance of risk and reward. Therefore, Board staff sees the advantage of using a reference point that is greater than what was achieved under COS regulation.

Board staff is of the view that when the actual normalized ROE exceeds the approved ROE on a sustainable basis (i.e. two consecutive years) by 400 basis points or more, the Board should initiate a review of the IR plan.

Some parties were of the view that this threshold was too low and that it should be increased to 500/600 basis points while others thought it was too high and that it should be reduced to 300 basis points. Board staff thinks that the 400 basis points is an appropriate reference point that balances the needs of customers and shareholders.

[10] EB-2006-0034, Exhibit 1, Tab 24, Schedule 45
[11] RP-2002-0158 / EB-2002-0484, Exhibit J2.31, Attachment #1

Board staff is also of the view that the off-ramps should be symmetrical. This means that the off-ramps should address economic events that would not otherwise be eligible for a Z factor but nonetheless threaten the financial viability of the utilities.

Board staff is of the view that when the actual normalized ROE is below the approved ROE on a sustainable basis (i.e. two consecutive years) by 400 basis points or more, the Board should initiate a review of the IR plan.

3.10 Demand Side Management (DSM)

In 2006, the Board convened a generic proceeding (EB-2006-0021) to address a number of common issues related to DSM activities.

In its August 25, 2006 Decision with Reasons for Phase 1 of that generic proceeding, the Board determined the following:

- A three-year term for the first DSM plan;
- Processes for adjustments during the term of the plan;
- Formulaic approaches for DSM targets, budgets, and utility incentives;
- How costs should be allocated to customer rate classes;
- A framework for determining savings;
- A framework and process for evaluation and audit; and
- The role of the gas utilities in electricity conservation and demand management activities and initiatives.

The Board also outlined the DSM budgets for the DSM plan. The budget for Enbridge is $22.0 million in 2007, $23.1 million in 2008 and $24.3 million in 2009. Union's budget for each of those years is $17.0 million, $18.7 million and $20.6 million.

The Board also approved the structure and application of the LRAM, shared savings mechanism and demand side management variance account.

The second phase of the generic proceeding dealt with the input assumptions and the Board issued its Decision on October 18, 2006 on that particular matter.

During the current consultations, stakeholders generally agreed with Board staff's view that DSM activities in the years 2007-2009 as outlined in the Board's Decision with Reasons in proceeding EB-2006-0021 should be considered as a Y factor (i.e., as a cost pass-through adjustment). Furthermore, if the DSM plan is extended beyond fiscal year 2009, these DSM activities would continue to be treated as a Y factor throughout the plan term.

There was also agreement that DSM initiatives contribute to declining average use. However, concerns were raised about the potential for double counting. In particular, the continued use of the LRAM and compensating for declining average use in the X factor (or in a separate factor) could lead to double counting. The reason for this, as some parties observed, is that embedded within the utilities' actual normal average uses are volumetric losses captured in the LRAM. Board staff supports the continued use of the LRAM and therefore believes that the derivation of the declining average use factor should avoid or minimize double counting.

3.11 Reporting Requirement

Under an IR plan, the utilities should be required to make periodic reports to the Board. These reporting requirements would allow the Board to monitor the utilities' performance throughout the plan term.

Board staff found little consensus among stakeholders regarding the information, timing and frequency of the reporting requirements for the IR plan. There was general consensus, however, that reported information should be in the public domain. Some consumer groups suggested that Enbridge and Union report information on a quarterly basis, others on a semi-annual basis, while others also proposed a mid-term review in the third year of the IR plan. Union and Enbridge indicated a preference for annual reporting requirements and thought that the existing Gas Reporting and Record-Keeping Requirements ("Gas RRRs") were adequate.

With respect to efficiency improvements, some parties thought that the utilities should outline a plan for achieving sustainable efficiencies and update it annually to track progress. Also, they believed that Enbridge and Union should differentiate sustainable efficiencies from unsustainable (short term cost-cutting) efficiencies.

In the NGF Report, the Board stated that it would consult with stakeholders and modify the Gas RRRs as necessary to meet the requirements for financial reporting in the new ratemaking framework. The Board also stated that it would ensure that the appropriate financial information would be accessible to stakeholders but that it did not intend to institute a formal public process for reviewing this information.

Board staff has reviewed reporting requirements in other jurisdictions.[12] This review found that reporting requirements range from quarterly to annual filings. Terasen Gas Inc. ("Terasen"), regulated by the British Columbia Utilities Commission ("BCUC") and under a four year IR plan, has an annual review process with semi-annual customer advisory council meetings. The BCUC also

[12] A summary of the jurisdictional review is available from the OEB website

approved the inclusion of a "No Surprises" clause. This clause is intended to ensure that any significant changes or company restructurings are disclosed to interested parties by the utility in a timely manner. Many stakeholders in the current consultation supported this clause.

Board staff is of the view that the utilities should file the following information with the Board: annual financial filings; and annual service quality monitoring information. Further detail is outlined below.

3.11.1 Annual Gas Reporting and Record-Keeping Filings

To monitor the utilities during a multi-year rate plan, Board staff sees merit in amending the Gas RRRs to include the following additional information:

- Standard ROE calculation schedules: ROE calculations should include actual and weather-normalized financial information. The specific methodology will need to be determined. The purpose of this requirement is to support the off-ramp determination.

- Capital expenditures: Annual actual capital expenditures by USoA accounts should be included. This requirement will support rebasing at the end of the plan term.

In addition, Board Staff is of the view that the Gas RRR should be amended to include Service Quality Requirements ("SQR") filings. These new financial and SQR filings should be publicly available.

"No Surprises" Clause

As previously mentioned, this clause is intended to ensure that any significant changes or company restructurings are disclosed to interested parties by the utilities in a timely manner. While many stakeholders supported the inclusion of this clause, Board staff is not convinced that information disclosure after the fact would add value to the process. Board staff would benefit from further stakeholder input on why this information should be required, and the expectations as to how this information is to be used by the Board.

3.11.2 Service Quality Monitoring

Subsequent to the NGF Report, the Board undertook a consultation to amend the GDAR to implement the following service quality standards for the natural gas utilities:

- Telephone Answering Performance;
- Billing Performance;
- Meter Reading Performance;
- Service Appointment Response Times;
- Gas Emergency Response;
- Customer Complaint (Written) Response; and
- Disconnection/Reconnection.

The actual performance should be reported annually as part of the Gas RRRs.

Some of the consumer groups raised concern over the lack of incentives a utility would have to maintain service standards. In particular, it was suggested that the standards should include financial rewards and penalties as a means to encourage utilities to achieve service quality performance measures.

Board staff recognizes that stakeholders place great importance on performance standards being achieved by utilities. The current performance standards set out in the GDAR are mandatory, and achievement of the standards can therefore be monitored and adequately enforced through the Board's existing compliance process.

Through the compliance management process, Board staff can monitor trends in service quality and identify any concerns that might arise. Concerns regarding non-compliance with the GDAR performance standards, as well as concerns regarding the timeliness and accuracy of performance standard information filings, can be addressed through informal or formal enforcement action. The former would normally involve discussions between Board staff and the utility to achieve a fair and appropriate resolution of the issue. The latter can include the imposition of financial penalties.

3.12 Rebasing Requirements

In the NGF Report, the Board stated that it would expect to see, during the plan term, measures that are designed to improve the utility's productivity on a sustained basis – not temporary, unsustainable budget cuts. The Board also stated that it would, during rebasing, expect an analysis of the relationship between operation, maintenance and administration costs ("O&M") and capital expenditures, the timing of capital expenditures and the associated impacts on shareholders and customers. The Board also cautioned that sudden and significant increases in costs at the time of rebasing will be viewed unfavourably, unless thoroughly justified.

Board staff thinks that the Board should also review, at the time of rebasing, the key parameters of the IR plan for continued appropriateness. Furthermore, at the time of rebasing, it will be necessary to update the TFP study (i.e., the X and stretch factors will need to be re-examined). This exercise will require detailed data from the gas utilities. Therefore, to ensure data continuity, PEG will include a list of the data requirements in its TFP study.

The timing of expenditures (i.e., O&M and capital) that are made periodically is an issue of mounting interest in IR schemes. Some timing issues may be revealed at rebasing. In considering these rebasing rules, Board staff sees the merit in amending the Board's Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications ("MFR") to include actual COS data for each year of the IR plan term (e.g. 2008 - 2012) in the same format as required by the MFR.

In addition, Board staff is of the view that an average of spending over the IR plan should act as a guide to assess the validity of the utility's proposed O&M expenses and capital expenditures at the time of rebasing.

During the stakeholder consultation process, PEG suggested that rebasing could take into account an efficiency carryover mechanism that would act to bolster long-term performance incentives. For example, PEG indicated that the new rates could be set by applying a weight to the revenue requirement that would result from a COS review, and a one-year extension of the existing IR mechanism.

Some parties questioned whether this approach would not translate into just and reasonable rates. The concept of an appropriate efficiency carryover mechanism is however of interest to Bard staff. Comments from stakeholders on such a mechanism are encouraged.

3.13 Rate Setting Filings

To set annual rates during the IR plan, Board staff thinks that Enbridge and Union should file the information identified below annually by October 1st. This would allow the Board to issue a Rate Order by December 15th for new rates to be implemented for January 1st of the next rate year. Since NRG's fiscal year begins October 1st, it should be required to file the information identified below annually by July 1st with a rate order issued by September 15th:

- A draft rate order;
- A rate handbook with all supporting documentation including the inflation factor, X factor, stretch factor, and other rate adjustments, as well as an explanation of how rates have been adjusted to effect the IR formula; and
- The deferral and variance account balances for the current fiscal year (8 months of actuals and 4 months of forecast). The list should include the balances proposed for clearance, the methodology for clearance, unit rates for clearance, and the proposed timing of the clearance.

Board staff thinks that the process for these filings should be similar to the QRAM review process in that it would be fairly mechanical. This process would allow interested parties and Board staff to make submissions, and the utilities would have the opportunity to reply. An Excel spreadsheet model should be created for use by the utilities. This model would show the calculations supporting the draft rate order.

Other Rate-related Changes during Plan Term

A utility may apply for rate-related changes (i.e., rate re-design proposals and Z factors) during the plan term. However, as noted earlier the onus should be on the utility to demonstrate why the changes or adjustments are required.
If the rate-related changes are minor in nature and customer impacts are minimal, these changes could be included in the rate setting filing. However, if the rate-related changes are significant and require a longer review period, a separate application should be made on a sufficiently timely basis. It is possible that significant rate-related changes requiring particularly lengthy review may not be implemented until the following rate year.

4 OTHER ISSUES

4.1 Return on Common Equity

The return on common equity ("ROE") compensates investors for the risk associated with providing share capital to a utility business. The cost of that capital will vary with the perceived risk of the investment. In general, the rate of return to the investor should be commensurate with the risk of the utility as compared to that in the market.

The Board currently uses a formula-based approach to set the rate of return on common equity for regulated gas utilities. This approach was initially outlined in the Board's "Draft Guidelines on A Formula-Based Return on Common Equity" and was first applied to set fiscal 1998 rates for Enbridge. In 2003, the Board held a review of the ROE setting methodology in response to applications from the gas utilities (RP-2002-0158). The Board found that there was no compelling reason to adopt a different cost of capital methodology.

During the current consultation process, Union and Enbridge commented that the ROE outcome should be adjusted annually to recognize the capital intensiveness of the natural gas business. Other stakeholders did not agree since there would be some degree of double counting as the GDP IPI index includes some consideration of changes in cost of capital.

In its December 20, 2006 "Report on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors", the Board determined that changes in ROE and debt rates are implicitly recognized in changes in the GDP IPI and that no further explicit adjustment for changes in these parameters would be required.

This is also consistent with the Board's July 21, 2001 Decision with Reasons in proceeding RP-1999-0017 regarding Union's three-year PBR plan. In that Decision, the Board found that the ROE adjustment is captured in the annual changes of GDP IPI FDD. In particular, the Board noted that "the effect which inflation might have on the determination of a fair allowance for ROE is, to a significant extent, captured by annual changes in the GDP-IPI component of the PCI. The impact of the differences in capital intensity between Union and industrial companies in general is captured in part through the appropriate determination of the input price differential. In the Board's judgment, the components of a fair ROE, which reflect the risks to which the utility is exposed, are captured under a PBR approach, to a large extent, through the application of an appropriate price cap escalator that includes the I-factor and the X-factor".

Therefore, Board staff does not believe that an annual adjustment to the ROE is required.

4.2 Union's proposed weather-normalization methodology

In its Decision with Reasons in proceeding RP-2003-0063, the Board accepted Union's change to its weather normalization methodology. In particular, the Board allowed Union to forecast heating degree days based on a 70:30 weighting of the 30-year average forecast and 20-year trend forecast for fiscal year 2004. For each year thereafter, the Board indicated that it would consider 5% decreases and increases to the weighting of the 30-year and 20-year methodology respectively until such time as a 50:50 weighting is in place.

For the 2007 test year, Union's rates reflect a weighting of 55:45.

During the current consultation process, Union suggested using a 20-year trend forecast in its weather normalization methodology starting January 1, 2008. This would reflect a 0:100 weighting and would require a variance account to track adjustments to base rates during the plan term. Union's rationale was that this adjustment would result in symmetrical risk, that is, colder weather would be as likely to occur as warmer weather.

Most stakeholders disagreed with Union's suggestion, stating that the 2007 settlement agreement in proceeding EB-2005-0520 was accepted on the grounds that base rates would be adjusted for only one more year to reflect a 50:50 weighting.

Board staff agrees and believes that the base rates should be adjusted to reflect a 50:50 weighting in fiscal 2008.

4.3 Replacement Mains and System Expansion

This section addresses the treatment of capital investments for: regular main replacements, main relocations, system integrity and safety projects, and cast iron/steel main replacement programs. It also encompasses the treatment of system expansion to new communities (i.e., those not currently served by natural gas).

During the consultation, Enbridge expressed concerns over cost recovery of its main replacement program which includes an annual budget of $50.6 million for cast iron and $2.2 million for bare steel in each of 2007, 2008, and 2009.

Enbridge proposed that these costs be treated as a Y factor (or cost pass-through) to expedite cost recovery since otherwise it would not earn a return on these investments until rebasing.

Board staff is of the view that a comprehensive plan that encompasses both capital and O&M expenses creates stronger and more balanced incentives. For example, a plan that focuses only on O&M expenses may weaken incentives to control capital costs thereby reducing the overall potential performance incentives. In a capital intensive business such as natural gas distribution, containing capital expenditures is a key to good cost management. Therefore, Board staff sees advantages in dealing with all aspects of a utility's operations in a comprehensive fashion rather than using a "targeted" IR approach.

More specifically, staff expects that as a result of its mains replacement program, Enbridge will realize substantial O&M savings prior to rebasing. In addition, the TFP study conducted by PEG will examine input prices and productivity trends of 38 U.S. natural gas utilities. The TFP trends of these utilities will reflect all of their expenditures for capital replacement and customer attachments. As a result, it is expected that the X factor will reflect these considerations. Consequently, staff is of the view that the establishment of a cost pass-through mechanism for main replacement programs (including relocations) and safety and reliability projects is not warranted.

With regard to system expansions, Enbridge indicated that it may no longer invest to serve new communities under a comprehensive IR plan even if a project meets the profitability test (i.e., individual projects with a profitability index ("PI") of 0.8 and a rolling portfolio PI of 1.1 or more) specified in the "Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)" resulting from the Board's EBO 188 proceeding.

Board staff expects the utilities to continue to use the existing guidelines for system expansion. System expansions to new communities are expansions to communities that are not currently served by natural gas. In general, these communities are relatively small and may require expansion of the existing system by upwards of 10 to 50 kilometers. Conversion to natural gas generally occurs over a 5 – 10 year period (unless the existing heating is propane) because connections take place as furnaces need replacement. As a result, these projects generally have lower profitability indexes (even though these projects meet the EBO 188 guidelines). Thus, if not encouraged, the conversion to a "cleaner energy" could be compromised under an IR regime.

Therefore Board staff believes that a cost pass-through is an appropriate way to encourage the continuation of system expansion to new communities. Staff believes that this treatment should however be limited to projects that require a leave to construct approval from the Board. This would ensure that there would be a public review of costs and benefits associated with the expansion. The costs should also be offset by revenues generated from the new connections during the plan term. This approach recognizes that some of these projects have a “faster” conversion rate. For example, if the existing heating is propane, the conversion rate is usually faster.

Board staff notes that to avoid double counting, the TFP study will need to consider the expenditures pertaining to system expansions.

APPENDIX 1

List of Participants in EB-2006-0209

City of Kitchener
Consumers’ Coalition of Canada
ECNG
Enbridge Gas Distribution Inc.
Energy Probe
Green Energy Coalition
Hydro One Networks Inc.
Industrial Gas Users Association
London Property Management Association
Ontario Power Generation
Pollution Probe
School Energy Coalition
TransCanada Energy
TransCanada PipeLines Limited
Union Gas Limited
Vulnerable Energy Consumers Coalition

APPENDIX 2

Enbridge Miscellaneous Non-Energy Services

	Rider "G" Service Charges	Rate ($)
1	New Account Charge	25.00
2	Appliance Activation Charge	65.00
3	Meter Unlock Charge	65.00
4	Lawyer Letter Handling Charge	15.00
5	Statement of Account Charge	10.00
6	Cheques Returned Non-Negotiable Charge	20.00
7	Red Lock Charge	65.00
8	Removal of Meter	260.00
9	Cut Off at Main	1,200.00
10	Valve Lock Charge	125.00 – 260.00
11	Safety Inspection	65.00
12	Meter Test	97.50
13	Street Service alteration	32.00
14	NGV Rental Cylinder	12.00
	Other (ad-hoc request)	
15	Labour – hourly charge	130.00
16	Cut Off at Main – commercial & special request	custom quoted
17	Cut Off at Main – other	1,200.00
18	Meter In-out (residential)	260.00
19	Request for Service Call Information	30.00
20	Temporary Meter Removal	260.00
21	Damage Meter Charge (proposed for 2007)	360.00

Union Miscellaneous Non-Energy Services

	Service	Fee
	Residential Customer Class Service	
1	Connection Charge	$35
2	Temporary Seal - Turn-off (Seasonal)	$22
3	Temporary Seal - Turn-on (Seasonal)	$35
4	Landlord Turn-on	$35
5	Disconnect/Reconnect for Non-Payment	$65
	Commercial/Industrial Customer Class Service	
6	Connection Charge	$38
7	Temporary Seal - Turn-off (Seasonal)	$22
8	Temporary Seal - Turn-on (Seasonal)	$38
9	Landlord Turn-on	$38
10	Disconnect/Reconnect for Non-Payment	$65
	Statement of Account/History Statements	
11	History Statement (previous year)	$15/statement
12	History Statement (beyond previous year)	$40/hour
13	Duplicate Bills * (if processed by system)	No charge
14	Duplicate Bills * (if manually processed)	$15/statement
	Dispute Meter Test Charges	
15	Meter Test - Residential Meter	$50 flat fee for removal and test
16	Meter Test - Commercial/Industrial Meter	hourly charge based on actual costs
	Direct Purchase Administration Charges	
17	Monthly fee per bundled t-service contract	$75.00
18	Monthly per customer fee	$0.19

Notes:

* Duplicate bill charges only apply when customer wants two copies of a bill. List bills from the last billing period will be replaced free of charge.

Appendix B

d) The level of current rates and the magnitude of the proposed change;

e) The potential impact on customers;

f) The level of contribution to fixed cost recovery;

g) Customer expectations with respect to rate stability and predictability; and

h) Equivalency of comparable service options.

The revenue to cost ratios resulting from Union's 2007 rate design proposals have been filed at Exhibit H3, Tab 1, Schedule 1. For purposes of comparison, Union has also provided the RP-2003-0063 revenue to cost ratios approved by the Board for 2004 in column (j) of Exhibit H3, Tab 1, Schedule 1. The revenue to cost ratios reflect Union's application of accepted rate design principles and, as noted above, are underpinned by the cost allocation study filed at Exhibit G3, Tab 1 through Tab 5. The 2007 proposed revenue to cost ratios are within an acceptable range and are generally consistent with those approved by the Board in the RP-2003-0063 proceeding.

4. RESPONSE TO THE M2 DIRECTIVE

In the RP-2003-0063 rate proceeding, several intervenors challenged the design of rates for the M2 rate class on the basis that there were intra-class subsidies. The concern about intra-class subsidies arose from the fact that, in the current M2 rate design, a large portion of customer-related costs are recovered on a volumetric basis. In other words, because a significant portion of the customer related costs are recovered on a volumetric basis from the rate class, rather than through the monthly customer charge, larger volume customers contribute proportionately more to the recovery of fixed costs than do smaller customers.

In light of the concerns expressed by intervenors, the Board, at page 147 of the RP-2003-0063 Decision with Reasons, found that;

> "It is counter-intuitive that a high volume industrial user will incur the same amount of customer related costs as a residential customer. It seems unreasonable that Union cannot differentiate members of this class on the basis of consumption. The Board therefore directs Union to conduct a cost allocation and rate design study directed at separating low volume and high volume consumers currently within the M2 rate class. In designing the study, Union should consider rate implications at different volume breakpoints and should also consider the appropriate level of monthly fixed charges for each sub-class."

Union engaged the services of Navigant Consulting ("NCI") to review the cost allocation and rate design of the M2 rate class. Its report is provided at Exhibit H2. Union's response to the Board's directive is organized under the following headings:

- Union's Response to the M2 Directive; and,
- Pricing and Implementation.

UNION'S RESPONSE TO M2 DIRECTIVE

Union is proposing to replace the existing M2 rate class with two new general service rate classes. Consistent with the rate structures proposed by NCI, Union is proposing to create a small volume general service rate class for residential and non-contract commercial/industrial customers consuming 50,000 m^3 or less per year and a large volume general service rate class for customers consuming greater than 50,000 m^3 per year. The small volume general service rate class will be called the M1 rate class. The large volume general service rate class will be called the M2 rate class.

Union concluded that establishing two new rate classes is the best response to the Board's directive after considering the conclusions and recommendations of the NCI study, alternative rate designs that did not require splitting the rate class, and the costs associated with establishing new general service rate classes.

In Union's view, creating two new rate classes differentiated on the basis of volume is the most appropriate rate design option because:

a) It most effectively addresses the issue of the intra-class subsidy within the current M2 rate class by allowing for a more direct attribution of customer related costs to small and large volume customers;
b) It is consistent with the rate design principles used by Union in the design of all its rates in that it reflects differences in load profile and load factor and does not consider end use; and,
c) The impact on the billing system and the associated costs are not prohibitive. Union estimates the capital and ongoing annual O&M costs associated with modifying the billing system to be approximately $630,000 and $115,000, respectively.

Union also supports NCI's proposed breakpoint of 50,000 m^3. As indicated in the NCI report, the breakpoint of 50,000 m^3 results in less variation in average use per customer and load factor for each of the new rate classes when compared to the current M2 rate class. As a result, the new rate classes are more homogeneous.

Further, the breakpoint of 50,000 m^3 is the same as the current Board approved breakpoint for Rate 01 and Rate 10 in Union's Northern and Eastern Operation area. By adopting a breakpoint of 50,000 m^3 for the M1 and M2 rate classes, Union will have harmonized the eligibility criteria for Union's general service rate classes in both operating areas. The 50,000 m^3 breakpoint is also consistent with the Board's own guidelines for determining whether a gas marketer requires a licence to sell gas.

PRICING AND IMPLEMENTATION

Union is proposing to implement the new M1 and M2 rate classes effective January 1, 2008. Union is seeking approval of the M1 and M2 rate structures and rate levels in this proceeding. If approved by the Board, Union will make the billing system changes in 2007 and the M1 and M2 rates presented below will be the base 2008 general service rates to which any Incentive Regulation pricing adjustments would apply[1]. The proposed M1 and M2 rate schedules are provided at Exhibit H3, Tab 3, Schedule 2.

To determine the 2008 base rates for the M1 and M2 rate classes, Union is proposing to

1 The M1 and M2 rates presented below will also be adjusted to reflect the 2008 implementation of the Bill-ready component of GDAR. This adjustment is discussed later in this evidence.

use the results of the 2007 cost of service study adjusted to reflect the proposed annual volume breakpoint of 50,000 m^3. The total costs recovered by the proposed M1 and M2 rates in 2008 are equivalent to that recovered from the current M2 rate class in 2007 (assuming the same billing units). As a result, Union will be revenue neutral to the rate design change. The revenue proof for M1 and M2 is provided at Exhibit H3, Tab 11, Schedule 2.

Table 2 below provides the customer-related, other-delivery related and storage-related costs for the current M2 rate class and for the new M1 and M2 rate classes. Union notes that the total costs by cost component for the new M1 and the M2 rate classes are equal to the costs attributable to the current M2 rate class.

Table 2

General Service Customer-Related, Other Delivery-Related and Storage-Related Costs

Line No.	Particulars ($000's)	Current M2	Proposed M1	Proposed M2
1	Customer-Related	275,641	268,047	7,594
2	Other Delivery Related	138,927	98,797	40,130
3	Storage-Related	40,303	31,457	8,846
4	Total Allocated Costs	454,870	398,301	56,569

M1 Rate Class Structure and Pricing

The proposed structure of the M1 rate class, applicable to small volume general service customers, consists of a monthly customer charge and a three block declining delivery commodity rate structure. Table 3 provides the M1 rate structure and the proposed pricing.

Table 3

M1 Rate Class Structure and Pricing

Line No.	Particulars	Rate
1	Monthly Charge	$16
	Delivery Charge (cents/m^3)	
2	First 100 m^3	6.4237
3	Next 150 m^3	6.0945
4	All over 250 m^3	5.4237
5	Storage Charge (cents/m^3)	1.099

As is the case in the current M2 rate structure, the monthly customer charge is intended to recover a portion of the customer-related costs. Customer-related costs are costs that do not vary with peak day demand or throughput. Union is proposing a monthly customer charge for the M1 rate class of $16. The monthly customer charge recovers approximately 70% of the customer-related costs allocated to M1.

The remaining M1 customer-related and delivery-related costs are recovered through delivery commodity charges. The first block volume of 100 m^3 is intended to capture baseload consumption. The second block, next 150 m^3, accommodates the consumption of the average M1 customer and is priced to reflect the average price of the rate class. The final block, all over 250 m^3, accommodates customers with higher volume and is priced to ensure the smooth transition between M1 and M2.

Table 4 provides the annual impact of Union's proposals on customers of varying sizes within the M1 rate class. The rate impacts are derived by comparing the 2007 rates under the current approved M2 rate structure with the new M1 rates.

Table 4

Annual Customer Impacts at Various Consumption Levels

Line No.	Annual Volume (m^3)	Current Rate M2 ($/yr)	Proposed Rate M1 ($/yr)	Bill Impact ($/yr)	Change (%)
1	1,500	298	303	4	1.4
2	2,200	348	351	3	0.8
3	2,600	377	378	1	0.4
4	3,000	405	405	0	0
5	3,500	440	439	(2)	(0.4)
6	20,000	1,508	1,521	13	0.8
7	30,000	2,103	2,173	70	3.3
8	40,000	2,663	2,825	162	6.1
9	50,000	3,183	3,477	295	9.3

M2 Rate Class Structure and Pricing

The proposed structure of the M2 rate class, applicable to large volume general service customers, consists of a monthly customer charge and a four block declining delivery commodity rate structure. Table 5 provides the M2 rate structure and the proposed pricing.

Table 5

M2 Rate Class Structure and Pricing

Line No.	Particulars	Rate
1	Monthly Charge	$70
	Delivery Charge (cents/m^3)	
2	First 1,000 m^3	3.9738
3	Next 6,000 m^3	3.9037
4	Next 13,000 m^3	3.6571
5	All over 20,000 m^3	3.4544
6	Storage Charge (cents/m^3)	0.8038

Union is proposing a monthly customer charge for the M2 rate class of $70. The monthly customer charge is equivalent to that charged to Rate 10 customers in Union's Northern and Eastern Operations area. The monthly customer charge recovers approximately 77% of the customer related costs allocated to M2.

The remaining M2 customer-related and delivery-related costs are recovered through delivery commodity charges. The first block volume of 1,000 m^3 is intended to capture baseload consumption. The second block and third block, next 6,000 m^3 and 13,000 m^3, accommodates the consumption of most commercial/industrial customers. The final block, all over 20,000 m^3, accommodates customers with higher volume and is priced to ensure the smooth transition between rates M2, M4 and M7.

Table 6 provides the annual impact of Union's proposals on customers of varying sizes within the M2 rate class. The rate impacts are derived by comparing the 2007 rates under the approved M2 rate structure with the new M2 rates.

Table 6

Annual Customer Impacts at Various Volume Levels

Line No.	Annual Volume (m^3)	Current Rate M2 ($/yr)	Proposed Rate M2 ($/yr)	Bill Impact ($/yr)	Change (%)
1	60,000	3,688	3,649	(39)	(1.0)
2	80,000	4,667	4,558	(109)	(2.3)
3	100,000	5,618	5,462	(156)	(2.8)
4	250,000	12,587	12,097	(490)	(3.9)
5	500,000	23,871	22,828	(1,043)	(4.4)

Implications for Union's Unbundled Services

Consistent with Union's proposal to implement the new M1 and M2 rate schedules effective January 1, 2008, Union also proposes to implement new U1 and U2 rate schedules. The U2 rate schedule is currently applicable to general service residential and commercial/industrial customers taking the unbundled storage service. Effective January 1, 2008, Union proposes that customers with annual consumption of 50,000 m^3 or less taking unbundled storage service be served under a new U1 rate schedule. Customers with annual consumption greater than 50,000 m^3 taking unbundled storage service will be served under a new U2 rate schedule. Union is not proposing any changes to the structure or basis for determining the U1 and U2 rates. The proposed U1 and U2 rate schedules are provided at Exhibit H3, Tab 3, Schedule 2.

Ontario Energy Board **Commission de l'Énergie de l'Ontario**

EB-2005-0520

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

FOR RATES FOR FISCAL 2007

DECISION WITH REASONS

June 29, 2006

3. SPLITTING THE M2 RATE CLASS

3.1 BACKGROUND

3.1.1 An unsettled issue in this case is Union's proposal to replace the existing M2 rate class in its Southern Operations area with two new general service rate classes. The proposal was offered in response to a Board directive in Union's RP-2003-0063 rate case where the Board found that Union should conduct a study directed at separating the M2 rate class on the basis of low and high volume customers. Both types of customers are contained in the M2 class which gave rise to concerns about intra-class subsidies. This is because a relatively large proportion of customer-related costs are recovered on a volumetric basis.

3.1.2 The Board's directive is found at page 147 of its RP-2003-0063 Decision.

> It is counter-intuitive that a high volume industrial user will incur the same amount of customer related costs as a residential customer. It seems unreasonable that Union cannot differentiate members of this class on the basis of consumption. The Board therefore directs Union to conduct a cost allocation and rate design study directed at separating low volume and high volume consumers currently within the M2 rate class. In designing the study, Union should consider rate implications at different volume breakpoints and should also consider the appropriate level of monthly fixed charges for each sub-class.

3.1.3 Union retained Navigant Consulting (NCI) to review the cost allocation and rate design of the M2 rate class. Consistent with the rate structures proposed by the NCI study, Union proposed to create a small volume general service rate class for residential and non-contract commercial/industrial customers consuming 50,000 m^3 or less per year and a large volume general service rate class for customers consuming greater than 50,000 m^3 per year.

3.1.4 The small volume general service rate class would be called the M1 rate class. The large volume general service rate class would be called the M2 rate class.

3.1.5 Union's view was that creating two new rate classes differentiated on the basis of volume was the most appropriate rate design because it most effectively addressed the issue of the intra-class subsidy within the current M2 rate class by allowing for a more direct attribution of customer related costs to small and large volume customers. Union said that it is consistent with the rate design principles already in use by the utility in the design of all its rates in that it reflects differences in load profile and load factor and does not consider end use.

3.1.6 Another reason offered by Union was that the impact on the billing system and the associated costs was not prohibitive. Union estimated the capital and ongoing annual O&M costs associated with modifying the billing system to be approximately $630,000 and $115,000, respectively.

3.1.7 Union also supported NCI's proposed breakpoint of 50,000 m^3 because it results in less variation in average use per customer and load factor for each of the new rate classes when compared to the current M2 rate class. Union said that the new rate classes are more homogeneous than the old single undifferentiated M2 rate class. The utility also noted that the new M2 breakpoint would be the same as the current breakpoint for Rate 01 and Rate 10 in the Northern and Eastern Operation area thus resulting in harmonized eligibility criteria for the general service rate classes in both operating areas.

3.1.8 Union noted as well, that it would be revenue-neutral to the rate design change.

3.1.9 Union's proposal is to implement the new M1 and M2 rate classes effective January 1, 2008, after the billing system changes are made in 2007 to accommodate the new classes.

3.1.10 In terms of customer impacts in the new M1 class, Union's evidence indicated that delivery charge impacts varied between plus 9.3% and minus 3.0%. The larger (unfavourable) impacts in the range of 3.3% to 9.3% were noted across higher volume levels in the 30,000 to 50,000 m^3 annual consumption range. In the new M2 rate class, impacts ranged from minus 4.4% to plus 0.3%. The only unfavourable impact in the new M2 rate class was found at the 50,000 m^3 volume point.

3.1.11 Union's proposal to split M2 was opposed by several of the intervenors, most notably SEC. SEC presented a critique of the proposal prepared by its witness, Mr. Paul Chernick of Resource Insight Inc., that suggested Union's proposal is fundamentally flawed and should therefore be rejected. Further, Mr. Chernick said that the various ratepayer groups should have input into the process and with this in mind, Union should be directed to commission a new study, in consultation with affected ratepayers. A number of intervenors favoured additional consultation among interested ratepayer groups.

3.1.12 CCC suggested that Mr. Chernick did not offer a credible alternative to Union's proposal and that the underlying justification for Union's split proposal is not only reasonable but appropriate, and should therefore be accepted by the Board. VECC adopted the arguments of CCC on this matter.

3.2 BOARD FINDINGS

3.2.1 The Board is of the opinion that rate design should be based on the widely accepted principle of cost causality. Previous decisions on this matter have been consistent in rejecting the differentiation of rates for social reasons. Obtaining homogeneity of cost characteristics in the establishment of rate classes remains the optimum method of avoiding cross-subsidization.

3.2.2 In considering this issue, the Board is mindful of the fact that the Board decision in RP-2003-0063 was the impetus for Union's research activities and ultimately its proposal. As noted above, the Board expressed a view in its RP-2003-0063 Decision that the cost allocation and rate design study be directed at separating low volume customers from high volume customers. The Board notes that the direction to Union in that case was to conduct a study and to file it in a subsequent rate application.

3.2.3 Mr. Chernick's critique of Union's study, prepared by NCI, posits that end-use can be a factor in the establishment of rate classes. In submissions by SEC, the assertion was made that the Board indicated in RP-2003-0063 that it believed residential customers had a different load profile and cost characteristics than other customers. The Board does not accept SEC's interpretation of the Board's direction. The segment of the excerpt referenced that is pertinent is as follows.

> It is counter-intuitive that a high-volume industrial user will incur the same amount of customer-related costs as a residential customer. It seems unreasonable that Union cannot differentiate members of this class on the basis of consumption.

In the Board's view, a simple reading of the text indicates that the chosen examples of a high-volume industrial user and a residential customer were selected as known entities likely to be at opposite ends of the consumption range, not to select out residential use as having unique characteristics that intuitively warrant a separate rate class.

3.2.4 Mr. Chernick acknowledged under cross examination by CCC that SEC's proposal for more study may not necessarily result in any fundamental changes to the existing Union proposal. The Board is not of the opinion that end-use categories should be a decisive factor in the determination of rate classes. The Board is not persuaded by SEC's position or the evidence of its witness to direct Union to conduct further study prior to any differentiation of customers within the current M2 class.

3.2.5 LPMA provided its analysis of the Union position and rationale for support of using 50,000 cubic meters as the breakpoint. LPMA submitted that the load factors are more homogeneous in the proposed M1 and M2 rate classes than in the existing M2 class. LPMA drew attention to the split point of 50,000 cubic metres between the 01 and the 10 rate classes in Union's Northern and Eastern operations. The Board agrees with LPMA that these points have merit in support of the proposed rate class division.

3.2.6 LPMA, while supportive of Union's position, did provide an alternative proposal to be considered in the event that the Board found that it was premature to move ahead with the division of the existing M2 rate class. LPMA suggested as an alternative that Union be directed to collect peak-day data on a cross section of the M2 customer base. This would involve the installation of a statistically significant number of metering devices to distinguish the various load factors and consumption patterns. While the Board agrees that additional data may lead to a more precise division of rate classes it does not feel that the cost benefit analysis of the metering exercise has been contemplated in sufficient detail at this time.

3.2.7 The Board is of the view that on the full spectrum of options available in creating rate classes, the optimum number will be achieved through a process whereby cost effective analysis reveals adequately unique cost causality groupings of customers. The Board is convinced by the evidence in this application, that the proposed division of the M2 class is a movement in the appropriate direction.

3.2.8 For these reasons, the Board approves Union's proposal to split the M2 class into two new classes in accordance with its application.

Appendix C

intended to improve rate schedule clarity and provide for consistent wording between rate schedules. For example, current rate schedules refer to "Delayed Payment" in Union's Southern Operations area and to "Late Payment Charge" in Union's Northern and Eastern Operations area. Union is proposing to adopt the terminology used in the Southern Operations area in the Northern and Eastern area. The black line version of 2007 rate schedules can be found at Exhibit H3, Tab 3, Schedule 1.

9. Gas Distribution Access Rule ("GDAR") Implementation

As indicated at Exhibit D1, Tab 6, Union will implement the Bill-ready service component of GDAR on January 1, 2008. The $8.7 million capital costs associated with the Bill-ready service will be incurred prior to January 1, 2008, but were not included in Union's 2007 cost of service revenue requirement because the in-service date of the system changes is January 1, 2008. Union will start incurring annual O&M expenses of $138,000 in 2008. The increase in revenue requirement associated with the implementation of the Bill-ready service on January 1, 2008 will be $1.726 million.

Similar to how the Board pre-approved the phasing out of the Delivery Commitment Credit ("DCC") over a 5-year period in its RP-2002-0130 Decision (paragraph 270), Union is seeking, as part of this proceeding, pre-approval to change rates effective January 1, 2008 to reflect the phasing in of the compliance costs associated with the Bill-ready service component requirement of GDAR.

Union has provided the derivation and the allocation by rate class of the 2008 Bill-ready revenue requirement at Exhibit H3, Tab 11, Schedule 3. The 2008 Bill-ready costs are allocated to all in-franchise rate classes using the average number of customers in each rate class. This is consistent with how the 2007 GDAR costs have been included in rates.

Exhibit H3, Tab 11, Schedule 4 details proposed rates including the 2008 GDAR costs. As indicated above, 2008 base rates also reflect Union's proposal to split the M2 rate class.

EB-2005-0520

UNION GAS LIMITED

SETTLEMENT AGREEMENT

May 15, 2006

1. H1/T1/p22
2. J1.73

6.8 IS UNION'S PROPOSAL FOR PRE-APPROVAL TO CHANGE RATES EFFECTIVE JANUARY 1, 2008 TO INCORPORATE THE PHASING IN OF GDAR COMPLIANCE COSTS APPROPRIATE?

(Complete Settlement)

The parties accept Union's proposal for pre-approval to change rates effective January 1, 2008 to incorporate the $1.726 million in revenue requirement for the phasing in of GDAR compliance costs is reasonable subject to any forecast capital cost variances being captured in the GDAR deferral account and capital cost forecast variances being subject to review when deferral account balances are disposed of.

The following parties agree with the settlement of this issue: CME, FONOM & the Cities, CCK, CCC, Energy Probe, IGUA, LPMA, LIEN, SEC, VECC, WGSPG

The following parties take no position on this issue: Coral, EGD, OAPPA, OESLP, Sithe, SEM, TransAlta, TCPL

Evidence References:
1. H1/T1/p21
2. J3.35, J3.36, J14.88, J21.29, J21.30

6.9 IS UNION'S PROPOSAL FOR CHANGES TO T1, T3, U2, U5, U7, U9, S1, RATE 20 AND RATE 100 UNAUTHORIZED STORAGE OVERRUN RATES APPROPRIATE?

(Complete Settlement)

The parties accept Union's proposal for changes to T1, T3, U2, U5, U7, U9, S1, Rate 20 and Rate 100 unauthorized storage overrun rates.

The following parties agree with the settlement of this issue: CME, FONOM & the Cities, CCK, CCC, Energy Probe, IGUA, LPMA, SEC, VECC, WGSPG

The following parties take no position on this issue: Coral, EGD, LIEN, OAPPA, OESLP, Sithe, SEM, TransAlta, TCPL

Appendix D

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2006-0034**	
VOLUME:	**4**	
DATE:	**February 1, 2007**	
BEFORE:	**Gordon Kaiser**	**Presiding Member and Vice Chair**
	Paul Vlahos	**Member**
	Ken Quesnelle	**Member**

MR. DENOMY: Yes.
MR. KAISER: Which happens to be the category that your proposal does well in, as opposed to stability.
Is there some overlap between accuracy and symmetry? Are we measuring the same thing and, therefore, bumping the weight from 40 to 80?
MR. DENOMY: Is there some overlap between accuracy and symmetry?
MR. KAISER: Are we double counting in some sense? It seemed to me, just intuitively, accuracy is the difference between actual and what the model predicts. Symmetry is how close you go -- you know, there seems to be a similarity between those, between those two concepts.
In other words, a model that is high on accuracy is going to be high on symmetry. No?
MR. DENOMY: Excuse me for just one minute, please.
[Witness panel confers]
MR. DENOMY: You can -- accuracy, I think, would be the most important factor, and I think that you are correct in saying that the symmetry part would, to a certain extent, be captured by accuracy, yes.
MR. KAISER: I tried to actually do overnight a bit of analysis similar to this and without really understanding your analysis fully at C2, tab 4. But, again, what I was trying to do was compare the results of these different models.
MR. DENOMY: Okay.
MR. KAISER: I would like to put this table to you, if

I can. It may not -- it obviously doesn't have the weighting. It may be comparable to your accuracy table.

MR. MILLAR: Mr. Chair, would you like these marked as exhibits before we go any further?

MR. KAISER: Yes.

MR. MILLAR: The first one is undertaking N3.2 from RP-2003-0063. That will be K4.3.

EXHIBIT NO. K4.3: UNDERTAKING N3.2 FROM RP-2003-0063.

MR. MILLAR: This new document is a table showing actual and forecast Toronto degree days.

MR. KAISER: Table 4 on the second page, Mr. Millar, is gas supply --

MR. MILLAR: I'm sorry, Mr. Chair, are these from the current proceeding? I see the exhibit number at the top.

MR. KAISER: Yes. Those are the sources.

MR. MILLAR: I see. They're just pulled out of the existing record?

MR. KAISER: We pulled it from different parts of the existing record, but I am going to get the witness to confirm the data.

MR. MILLAR: That's fine. We can mark it as one exhibit?

MR. KAISER: That's fine.

MR. MILLAR: It will be K4.4, Mr. Chair.

EXHIBIT NO. K4.4: TABLE SHOWING ACTUAL AND FORECAST TORONTO DEGREE DAYS.

MR. KAISER: First of all, Mr. Denomy, I went back and looked at your formula and I failed to see how I could convert Toronto degree days to gas supply degree days, and there's two sets of data floating around in this record. Is there a formula somewhere that does that?

MR. DENOMY: Yes.

MR. KAISER: I thought you referred us to one yesterday, but I couldn't make it work.

MR. DENOMY: If you refer to Exhibit C2, tab 4, schedule 1, page 23, and if you hook at the bottom of page 23 under table 13, footnote B, you can see the equation for converting Environment Canada degree days to gas supply degree days is the following: Gas supply degree days are equal to 1.5 -- excuse me, 156.7881, plus 0.94496, times Environment Canada degree days.

So if you are looking at column 2, you can see the forecast of Environment Canada degree days for fiscal 2006 is 3,681 degree days. You apply that to the formula I just read, and you end up with 3,635 degree days, gas supply degree days.

MR. KAISER: All right. So I see it now. So in 2005, 3,772, which is on table 13 of this page, that matches the 2005 figure that I have given you in my exhibit. So the Toronto degree days are the same as Environment Canada degree days?

MR. DENOMY: The Toronto degree days are the same as the Environment Canada degree days, yes.

MR. KAISER: Okay. So let's just go to this latest document, the 2005 we had the actual 3772, which corresponds to your evidence at C2, tab 4, schedule 1.

Then we have Mr. de Bever's number that would result with his model.

MR. DENOMY: Yes.

MR. KAISER: He's higher by 34 degree days.

MR. DENOMY: Yes.

MR. KAISER: Which you would say would lead to -- is an indication of forecasting excess revenue.

MR. DENOMY: Forecasting excess revenue?

MR. KAISER: Right.

MR. DENOMY: Yes.

MR. KAISER: So the previous two years, he was under. Here he is 1 percent over. Previous two years he is under by 6 percent and 9 percent. 2002 he was over by 13 percent.

MR. DENOMY: Yes.

MR. KAISER: So then I went to the 20-year trend and that would have got us, instead of over in 2005, it would have got us under by 125 degree days.

MR. DENOMY: Yes.

MR. KAISER: Which is three percent. So if we were just to look at accuracy in this one year, I know you can't look at one year, de Bever was more accurate.

MR. DENOMY: If you are just looking at the one year, 2005, de Bever would be more accurate, yes.

MR. KAISER: Now, then what I tried to do is calculate the average error. So de Bever, I got 111, a difference of 3 percent on the complete term, 1990 to 2006. Using your

20 degree, I got minus 7.

MR. DENOMY: Yes.

MR. KAISER: You would agree with those numbers?

MR. DENOMY: Yes, I do, subject to check, sure.

MR. KAISER: So am I to understand just this point, if the Board used de Bever and this was representative, this 20-year term, whatever it is, 1990 to 2006, 16 years, I guess, de Bever would have got us 3 percent over and 20-year trend would have got us 7 percent under.

MR. DENOMY: Would have gotten us 0. --MR. KAISER: I’m sorry, 0.2.

MR. DENOMY: Under.

MR. KAISER: So looking at my numbers, it would correspond with your conclusion that 20-year trend is more accurate?

MR. DENOMY: Yes.

MR. KAISER: Then I went to see what would happen if we used the Union one that the Board determined in the Union case, this 50/50.

MR. DENOMY: That's the last three columns.

MR. KAISER: That was 4 percent over.

MR. DENOMY: Yes.

MR. KAISER: So that would be less accurate than even de Bever?

MR. DENOMY: Yes.

MR. KAISER: All right, thank you, Mr. Denomy.

MR. DENOMY: You're welcome, sir.

MR. KAISER: Sorry, Mr. Shepherd.

Appendix E

Source: ExC2/T4/S1/p9

Table 5

Actual and Forecast Toronto Degree Days

Year	Actual	DeBever	Difference	% Difference	20-Yr Trend	Difference	% Difference	Union	Difference	% Difference
1990	3,980	4,032	52	1%	4,003	23	1%	4,092	112	3%
1991	3,610	4,035	425	12%	3,973	363	10%	4,075	465	13%
1992	4,053	4,035	-18	0%	3,962	-91	-2%	4,069	16	0%
1993	4,168	3,947	-221	-5%	3,865	-303	-7%	4,014	-154	-4%
1994	4,331	3,998	-333	-8%	3,870	-461	-11%	4,018	-313	-7%
1995	3,785	4,046	261	7%	3,883	98	3%	4,023	238	6%
1996	4,266	4,132	-134	-3%	3,942	-324	-8%	4,057	-209	-5%
1997	4,063	4,082	19	0%	3,863	-200	-5%	4,008	-55	-1%
1998	3,389	4,142	753	22%	3,896	507	15%	4,025	636	19%
1999	3,475	4,129	654	19%	3,929	454	13%	4,038	563	16%
2000	3,616	3,977	361	10%	3,833	217	6%	3,974	358	10%
2001	3,782	3,859	77	2%	3,748	-34	-1%	3,920	138	4%
2002	3,337	3,759	422	13%	3,683	346	10%	3,874	537	16%
2003	4,102	3,737	-365	-9%	3,684	-418	-10%	3,865	-237	-6%
2004	3,785	3,570	-215	-6%	3,614	-171	-5%	3,815	30	1%
2005	3,772	3,806	34	1%	3,647	-125	-3%	3,831	59	2%
2006	N/A									
Average Error 1990-2005	**3,845**	**3,955**	**111**	**3%**	**3,837**	**-7**	**-0.2%**	**3,981**	**137**	**4%**
No. of Times Overforecasted			10			7			11	

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Appendix F

Rate Adjustment Indexes for Ontario's Natural Gas Utilities

Pacific Economics Group, LLC
Economic and Litigation Consulting

Rate Adjustment Indexes for Ontario's Natural Gas Utilities

20 June 2007

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EXECUTIVE SUMMARY

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

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

Pacific Economics Group ("PEG") is the advisor to Board staff on IR issues. Staff initially directed PEG to undertake input price and productivity research that would support the development of the X factor of the summary PCI. It has since asked, additionally, for the development of a revenue cap index ("RCI") and of PCIs for important service groups. Under a revenue cap plan, the escalation in the revenue requirement for each utility would be limited by the RCI. The RCI would grow each year at the pace of last year's inflation in a gross domestic product implicit price index less an X factor plus output growth. The X factor would be the sum of a productivity differential, an input price differential, and a stretch factor. A balancing account would be required to ensure that the revenue requirement is recovered. Therefore, the utilities would be compensated for any decline in average use. Conversely, if revenue is greater than allowed by the RCI, the balancing account would capture a balance owing to ratepayers.

This document reports the latest results of our expanded research agenda. An earlier draft of the report, released on June 8, contained preliminary calculations for service group

PCIs. The revised report contains the final calculations. A redlined version of the manuscript will be made available that identifies all changes to the June 8 draft.

Overview of Research

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

Established methods and publicly available data from respected sources were employed in the research. The sample period for the US work was 1994-2004. Due to the restructuring of Ontario's gas industry in 1998 and other special circumstances, the sample period for the Enbridge and Union indexing work was limited to 2000-2005.

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

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

The issuance of a preliminary report resulted in helpful comments that have prompted us to revise our research methods in several important respects. On the basis of the new work, we recommend the use of the COS approach for the design of the rate adjustment mechanism.

Our research has culminated in recommendations for the design of rate and revenue cap indexes for Enbridge and Union. We believe that these recommendations are just and reasonable, and can place incentive regulation of Ontario's gas utilities on a solid foundation of economic reasoning and empirical research.

Key Results

The following table details our proposals for the X factors of the summary PCIs. It also provides, in italics, a notion of the likely growth in these PCIs during the IR plan. This projection requires an assumption regarding GDPIPI growth, and we use for this purpose the recent historical trend. The growth in the *actual* PCI would reflect the growth in the actual GDPIPI for final domestic demand during the IR plan period. The table presents, finally, indexes computed by PEG of the trend in each company's rates during the 2000-2005 period.

Summary Price Cap Indexes

	Enbridge	Union
Productivity Differential	0.89	0.52
Input Price Differential	0.27	0.22
Average Use Factor	-0.81	-0.72
Stretch Factor	0.50	0.50
X Factor [A = sum of above]	**0.85**	**0.52**
Recent GDPIPI Trend [B]	*1.86*	*1.86*
***PCI** [B-A]*	***1.01***	***1.34***
Summary Rate Trends	***1.37***	***0.87***

It can be seen that, for both companies, PCI growth would be materially slower than the growth in the GDPIPI. Ontario gas consumers would, in other words, experience growth in rates for gas utility services that are below the general inflation in the prices of final goods and services in Canada. The higher X for Enbridge is chiefly due to its greater opportunities to realize scale economies. The notional PCI trend is, for each company, quite similar to the overall trend in their actual rates during the 2000-2005 period.

Here are some details of our recommendations for the PCIs for individual service groups. Separate PCIs have been designed for each rate class that includes residential service. The rates for all other services would be subject to common but company specific

PCIs. We once again provide in italics a notion of the likely trend in these indexes during the plan using the recent historical trend in the GDPIPI.[2]

Service Group PCIs

Company	Service Group	Sum of Common Terms [A]	ADJ [B]	**Total X Factor [C]=A+B**	*Recent GDPIPI Trend [D]*	***Notional PCI Growth [D]-[C]***
Enbridge	Rate 1	0.85	-0.48	**0.37**	*1.86*	***1.49***
	Nonresidential	0.85	0.69	**1.54**	*1.86*	***0.32***
Union	Rate M2	0.52	-0.65	**-0.13**	*1.86*	***1.99***
	Rate 01	0.52	-0.65	**-0.13**	*1.86*	***1.99***
	Nonresidential	0.52	1.26	**1.78**	*1.86*	***0.08***

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

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

Here are workable formulas for revenue caps that are supported by our research. The featured methodology is one that is applicable to Union ---with its large transmission system--- as well as Enbridge. We once again provide in italics a notion of the likely trend in these indexes during the IR period.[3]

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

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

Revenue Cap Indexes

	Enbridge	Union
Productivity Differential [A]	0.89	0.52
Input Price Differential [B]	0.27	0.22
Stretch Factor [C]	0.50	0.50
X Factor^{RCI} [D=A+B+C]	**1.66**	**1.24**
Output Growth [E]	**2.83**	**1.92**
GDPIPI [*F*]	*1.86*	*1.86*
***Indicated RCI Growth* [*F-D+E*]**	***3.03***	***2.54***[4]

It can be seen that the RCIs grow more rapidly than the corresponding PCIs. This is due chiefly to the fact that an RCI is designed to compensate the utility for its *cost* trend rather than its *unit* cost trend.

Input Price Differential

We compared the input price trends of Ontario gas utilities to that of Canada's economy using both capital costing methods. We chose the 1998-2005 period as the one ending in 2005 that was well suited for calculating the IPD using COS capital costing. We found that the appropriate input price differentials for Enbridge and Union were 0.27% and 0.22% respectively. This is to say that the trend in the economy's input prices was a little more rapid than the trend in the industry's.

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. Under the COS approach to capital costing the annual TFP growth of Enbridge and Union averaged 0.71% and 1.87% 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-

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

year IR plan. This raises a concern that Enbridge customers did not, in the long run, benefit from the company's IR plan that targeted O&M expenses.

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

Research of two kinds was undertaken to select appropriate target rates of TFP growth for Enbridge and Union from the US results. One approach was to calculate the average TFP trends of peer groups consisting of US companies with similar opportunities to realize economies of scale. Over the full 1994-2004 sample period in our US sample, we found that the Enbridge peer group averaged 2.13% annual TFP growth, more than twice the company's actual 2000-2005 trend.   The Union peer group averaged 1.88% annual TFP growth, remarkably similar to 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 2.10% and 1.73%, respectively. We recommend that the TFP targets for Enbridge and Union be set at their econometric TFP projections.

The productivity differentials that follow from these recommendations depend on the productivity growth trend of 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 1.21% during the 1998-2005 period used. The indicated productivity differential for Enbridge is thus 0.89% (2.10 – 1.21).   The productivity differential for Union is 0.52% (1.73 – 1.21).

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 increased 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 and input price inflation are the principle drivers of higher cost of gas distributor base rate inputs.

For the PCI, the AU factor was calculated as the difference between the revenue-weighted and elasticity-weighted output indexes. Weather normalized volumes are used in these calculations. For Enbridge and Union, the AU factors are -0.81 and -0.72. The PCI adjustment for declines in average use excludes the effect of the Lost Revenue Adjustment Mechanism ("LRAM"). For the RCI, a balancing account would ensure that the allowed revenue requirement is exactly recovered and, therefore, an AU factor is not required.

Stretch Factor

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

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

A third piece of information that is relevant in stretch factor selection is operating efficiency. As it happens, no evidence has been brought to our attention concerning the recent operating efficiency of Enbridge or Union. We, accordingly, have no basis for adjusting the X factor for this consideration. Utilities should demonstrate superior performance with convincing benchmark evidence if they wish to receive special rate treatments. Based on the evidence at hand, we recommend a conventional 0.50% stretch factor for both companies.

Price Caps for Service Groups

PCIs for specific service groups were established by calculating X factors that were the sum of the X factor from the summary PCI and a special adjustment term, ADJ. The ADJ term varies by service group and effectively creates a custom X factor and PCI for each group. Original theoretical and empirical research was undertaken to provide a foundation for the design of the ADJ term. The basic idea is to effect an adjustment to X that reflects an estimate of the special impact of the service group on the growth the utility's base rate revenue and cost. A service class with declining volume per customer is more likely to have a negative ADJ that makes the X factor smaller so that the PCI for the group rises more rapidly. We recommend that there be separate PCIs for all of the rate classes that contain residential customers. The other service classes of Enbridge and Union would be subject to common, company-specific PCIs.

Revenue Cap Index

Revenue cap indexes ("RCIs") were also calculated using the index results. The index formula includes a specific term for output growth because RCIs compensate utilities for growth in cost rather than unit cost. We recommend the elasticity weighted output quantity index for this purpose. If the revenue requirement is allocated, and rates are designed, by traditional means there is no need for AU or ADJ terms in the X factor formula.

1. Introduction

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

In 2004, the Board convened a Natural Gas Forum to consider the future of Ontario gas utility regulation. In its final report on the Forum the Board found that its goals for the regulation of base rates are best served by multiyear IR plans with annual rate adjustment mechanisms designed with the aid of index research.[5] 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".[6]

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.

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

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

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

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

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

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

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

These and other comments of stakeholders and Board staff prompted upgrades in our methods that materially altered some of the research results.

This document reports our latest research results. An earlier draft of the report, released on June 8, contained preliminary calculations for service group PCIs. The revised report contains the final calculations. A redlined version of the manuscript will be made available that identifies all changes to the June 8 draft.

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

2. INDEX RESEARCH AND INCENTIVE REGULATION

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

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

2.1 Price and Productivity Indexes

2.1.1 TFP Basics

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

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

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

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

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

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

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

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

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

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

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

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

2.1.2 Sources of TFP Growth

Theoretical and empirical research has found the sources of TFP growth to be diverse.[7] One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

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

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

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

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

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

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

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

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

2.1.3 Price Indexes

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

2.2 Role of Index Research in Regulation

2.2.1 The Unit Cost Standard for PCI Design

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

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

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

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

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

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

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

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

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

The result in [5] provides a conceptual framework for the design of price cap indexes. We will call this framework the industry unit cost paradigm. Growth in a utility's rates can be measured by an actual price index. A PCI can limit the growth in this index. A stretch factor established in advance of plan operation can be added to the formula which slows PCI growth in a manner that shares with customers the expected benefits of performance improvements due to the stronger performance incentives of the IR plan.[8] A PCI is then *calibrated* to track the industry unit cost trend to the extent that

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

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

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

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

It follows that the trend in an industry's *unit* cost is the difference between the trends in industry input price and TFP indexes.[9]

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

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

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

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

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

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

9 Here is the full logic behind this result:

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

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

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

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

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

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

Implementation cost also depends on the feasibility of calculating current long run trends accurately. Methods have been developed to measure the recent long run trend in the TFP of the industry. For example, the drivers of fluctuations in volatile delivery volumes are well understood, and these volumes can be normalized so that calculations of the long term trend are less sensitive to the choice of a sample period. The recent long run trend in an industry's TFP is, moreover, often if not always a good proxy for the *prospective* trend over the next several years.[10]

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

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

Examination of input prices in the gas distribution industry suggests that they are somewhat volatile. Since gas distribution is capital intensive, the summary input price index is quite sensitive to fluctuations in the price of capital. The trend in a properly constructed capital price index depends on trends in plant construction costs and the rate of return on capital. Both of these components are more volatile than the general run of prices in our economy. The rate of return on capital depends on the balance between the supply of and the demand for funds, and reflects expectations regarding future price inflation.[11] From the late 1970s through the mid 1980s, for instance, yields on long-term bonds were far above historical norms due in large measure to inflation worries spurred by oil price shocks. They fell gradually for many years thereafter as concerns about inflation receded. More recently, long bond yields have been held down by efforts of the governments of China and other

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

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

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

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

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

2.2.2 Input Price and Productivity Differentials

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2.2.3 Average Use Factor

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

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

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

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

2.2.4 Revenue Cap Indexes

A revenue cap index ("RCI") caps the growth in a company's revenue requirement. Such an index is commonly paired with a balancing account that ensures that the revenue requirement is ultimately recovered. This tandem of IR plan provisions provides automatic compensation to the utility for declines in average use. The ratepayer therefore absorbs the risk of average use trends.

Index logic provides a framework for RCI design. The task is to provide automatic adjustments for the financial impact of changing business conditions on *cost* rather than *unit* cost. Cost theory reveals that the trend in the cost of a firm or industry can be decomposed into three terms, as follows:

$$trend\ Cost = trend\ Input\ Prices - trend\ TFP + trend\ Output \qquad [14]$$

In this relation there is a stand-alone measure of growth in utility output. Its design should be consistent with the output measure used to calculate the TFP trend.

If the GDP-IPI is used as the inflation measure, we obtain the following operational RCI.

$$growth\ RCI = growth\ GDPIPI - [PD + IPD + SF] + trend\ Output \qquad [15]$$

It can be seen that this RCI formula, like the PCI formula in [13], includes an inflation measure and an X factor that includes PD, IPD, and SF terms. There is no AU factor in X, however, because the average use trend is addressed by the balancing account. Provided that revenue is allocated to service groups by traditional means there is no need to calculate RCIs for specific service groups. Revenue cap indexes are sometimes applied to revenue requirement components such as O&M expenses.

Some RCIs that have been approved for use in regulation use formulas other than [15] which reflect certain simplifying assumptions. A common simplification is to use the number of customers as the output measure.[12] When this is done, the terms of [15] can be rearranged to yield a revenue *per customer* index with formula:

$$growth\ Revenue/Customer = growth\ GDPIPI - [PD + IPI + SF].$$ [13]

If the growth in GDPIPI equals X, this formula becomes a revenue per customer *freeze*:

$$growth\ Revenue/Customer = 0.$$ [14]

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

[13] A revenue per customer cap was approved for the base rate revenue requirement of Southern California Gas. The inflation rate measure in this formula was industry-specific.

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

Note, finally, that if X equals the growth in the output measure the X factor and output growth terms of the RCI formula cancel and the RCI formula reduces to:

$$growth\ RCI = growth\ GDPIPI.$$[15]

2.3 Conclusions

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

1. In a PCI formula of GDPIPI-X form, the PCI can be calibrated to track the industry unit cost trend provided that it contains four terms: PD, IPD, AU, and SF.
2. In computing the PD, the industry TFP trend is calculated using an elasticity-weighted output index.
3. The average use factor is the difference between the trends in revenue and elasticity weighted output indexes.
4. Index logic also provides formulas for the design of revenue cap indexes. In this formula, there is an explicit measure of output growth and the X factor is the sum of PD, IPD, and SF. The output index used to measure the TFP index should be consistent with the stand alone output growth term and both should capture the impact of output growth on cost.

[15] This formula has been used in approved revenue cap plans for the gas and electric power distribution services of Pacific Gas & Electric and San Diego Gas & Electric and the gas distribution services of Southern California Gas.

3. EMPIRICAL RESEARCH

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

3.1 Data Sources

3.1.1 United States

The primary source of the data used in our US gas utility cost research has changed over time. For the earliest years of the sample period the primary source was *Uniform Statistical Reports* ("USRs"). Many US gas utilities file these annual reports with the American Gas Association.[16]

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

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

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

Our TFP trend calculations are based on quality data for 36 US utilities. The sample includes most of the nation's larger utilities.[17] The sampled utilities are listed by region in Table 1. Inspection of the table reveals that they account for about 45% of gas deliveries in the continental US. The regional distribution of sampled companies is uneven. For example, California utilities accounted for about 32% of the customers in the sample but for only 15% of all customers in the continental US. Utilities in the South Central States account for 2.5% of the customers in the sample but almost 15% of those in the continental US.

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

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

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

Table 1

SAMPLED US GAS 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		
Average Customers of Sampled Companies		867,229		

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

3.1.2 Ontario

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

3.2 Defining Cost

The trends in input price indexes and in the input quantity indexes used in TFP research were noted in Section 2.1 to be weighted averages of the trends in subindexes for different input groups. In indexes of each kind, the weight for each group is based 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 four 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 that contributed to net O&M expenses plus all expenses for pensions and other benefits. *Net* rather than *gross* salaries and wages are required to avoid double counting labour expenses that utilities capitalize. 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 pension and other benefit 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 US utilities we used their reported pension and benefit expenses without adjustment.

The cost of **natural gas** used in system operation was itemized only by Union, which operates numerous compressors on its transmission and storage system. 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 reported demand-side management expenses of the companies.

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

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

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

We 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 the Ontario cost of funds thus computed in our US research to promote comparability of results.

3.3 Productivity Research

3.3.1 Sample Period

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

We have gathered US data for the 1994-2004 period and find that, using weather normalized delivery volumes, this is a reasonable period for the calculation of the long term productivity trend. As for the Ontario utilities, sample period selection was complicated by the fact that the industry was restructured in the late 1990s to remove sizable utility appliance sales, rental, and maintenance programs. Inclusion of data from pre-restructuring years can result in TFP trends that are not necessarily reflective of what can be achieved prospectively. Note, also, that Enbridge reported that a change in accounting practices compromised the comparability of data from the 1990s. Faced with these circumstances we chose to focus on the 2000-2005 period for our Ontario productivity research.[18] While a six year sample period is not ideal for measuring long term trends, our quest is at least facilitated by the use of weather normalized volume data.

We added to the weather normalized volumes used in the revenue-weighted output indexes 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 compensation task is assumed to be left to other provisions of the IR plan.

3.3.2 Econometric Cost Research

The index logic traced in Section 2.2 revealed that output quantity indexes featuring cost elasticity weights are useful in the design of rate and revenue cap indexes. Most notably, they can be used to calculate TFP indexes that focus on cost efficiency trends so that the X factor can have, additionally, an explicit term for the average use trend. The TFP indexes used in this study for both US and Canadian companies employed output indexes with weights that are based on estimates of the elasticity of cost with respect to output. These estimates were drawn from an econometric model of the relationship between the ("total") cost of gas utility base rate inputs and various business conditions. PEG developed this model expressly for this project. The econometric research also has uses in fashioning TFP targets and the calculation of PCIs for particular service classes, as we discuss further below.

We estimated the parameters of two cost models using US data for the full 1994-2004 sample period.[19] [20] [21] One model was based on the COS approach to capital costing; the other on the GD approach. Using both models, we were able to identify a number of

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[18] 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.

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

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

[21] The addition of Ontario data to the sample would have involved major complications and prolonged the study but had little impact on results.

statistically significant drivers of gas utility cost and to achieve a high degree of power to explain variations in the sample data.

The choice of output quantity subindexes for the econometric cost research was limited by the available US 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 power generation) customers, and the number of customers served.

All three of these quantity variables were found to be statistically significant cost drivers in both models. Moreover, our research suggests that economies of scale are substantial in the gas utility business and are an important source of productivity growth in the longer run. At sample mean values of the business conditions, for instance, we find in the model with COS costing that simultaneous 1% growth in all three output measures raises the total cost of service by only 0.87%. The incremental scale economies from output growth are even greater for large companies like Enbridge and Union than they are for smaller companies. This is due, apparently, to special economies in the delivery of volumes, which are characteristic of piping systems.

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

- Cost was higher the higher was the price of capital services
- Cost was higher the higher was the price of labour
- Cost was higher the higher was the share of cast iron in the total miles of gas mains.
- Cost was 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 1.4% annually for reasons other than changes in the specified business conditions. Since the 1.4% 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 are 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.[22] 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 US data. Details of this work are discussed in Appendix Section A.1.2.

In the research supporting the first draft of this report the index weights in the output indexes used in TFP research were the same for all US and Ontario utilities and reflected the estimated elasticities at sample mean values of the US business conditions. The resulting weights for residential and commercial volumes, other volumes, and the number of customers served were 15%, 11%, and 74% respectively. In the latest research we calculate elasticity-weighted output indexes using elasticity estimates that vary by company and reflect each company's special operating conditions.

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 constructing such indexes for Enbridge and Union we added to the weather normalized volumes certain estimates, provided by the companies, of their demand-side management ("DSM") savings. This treatment, combined with the exclusion of DSM expenses from cost, was undertaken in the hope that the PCIs will not compensate the utilities for their

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

DSM activities. This compensation task is assumed to be left to other provisions of the IR plan.

The shares of each billing determinant in *revenue* served as weights in these indexes. Both Ontario utilities provided us with highly detailed data on billing determinants and the corresponding revenues. These data permitted us to develop revenue-weighted output quantity indexes of considerable sophistication. The detailed data that Union provided pertained to their actual output and revenue. Enbridge provided detailed data for actual output and for the revenue requirement approved by the Board in establishing rates. While the revenue shares for the two companies are thus drawn from different sources we expect that both will yield satisfactory results.

The subindexes that we used to construct the revenue-weighted output quantity indexes for US utilities were, 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 US data on the corresponding revenue shares, we employed instead the average of the revenue shares for Union and Enbridge. 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. The residential and commercial sectors account for more than 95% of customers served. Our research thus suggests that gas utility finances will be sensitive to change in the average use of residential and commercial customers. If use per customer declines, for example, cost is apt to grow more rapidly than revenue and utilities will find themselves in need of more rapid rate escalation.

An issue that arose in the course of the research was whether to allow the revenue weights in the output indexes to change over time to reflect any changes over the sample period in the share of revenue drawn from the various billing determinants. Revenue shares can change materially over time if companies make material changes in the design of their rates. Index theory suggests that indexes with flexible weights are generally more accurate.

For this reason, they are often used in index research. The revenue shares of the rate elements (*e.g.* customer and volumetric chargers) of Enbridge and (especially) Union changed materially over the sample period, as an attempt was made to collect more revenue from customer charges. Since the number of customers grew more rapidly than delivery volumes, output indexes with flexible revenue weights grew more rapidly than indexes with fixed weights.

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. 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 at length in section A.4 of the Appendix. Each quantity subindex for labour was calculated as the ratio of salary and wage expenses to a labour price index. For the Ontario utilities we used as a labour price deflator an Ontario construction worker salaries and wages index. This was chosen in part because the available Stats Canada indexes of utility salary and wage trends displayed implausibly slow growth over the 2000-2005 period. An additional advantage of the construction worker compensation data is that data are available for *total* compensation as well as for *salaries and wages*.[23] The total compensation index is useful in the calculation of the input price differential, as we discuss further below.

For the US companies, National Compensation Survey ("NCS") data for 2004 were used to construct average wage rates that correspond to each distributor's service territory.

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

Values for other years were calculated by adjusting the 2004 level for changes in employment cost trends. For this purpose, we used the employment cost index ("ECI") for electric, gas, and sanitary workers. Regional labour price trends were obtained by adjusting the trends in this national ECI for the difference in the trends of *comprehensive* regional and national ECIs. All of these ECIs are calculated by the BLS.

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

3.3.5 Productivity Results

United States

Table 2 and Figure 1 report key results of our US TFP research. Findings are presented for the TFP index and the component output and input quantity indexes. The reported trends are size (specifically, cost) weighted averages of the trends for the 36 companies.[24] Using COS capital costing, it can be seen that over the full 1994-2004 sample period the average annual growth rate in the TFP of the sample was about 1.43%.[25] Output growth achieved a 1.37% average annual pace, whereas inputs averaged a slight -0.06% annual decline. Over the same period, the annual average growth rate in a federal government index of the trend in the multifactor productivity of the US private business sector was 1.39%.

We also calculated the productivity trend of the US utilities in use of O&M inputs. Their PFP indexes grew at a 2.23% 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 US utilities.

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

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

Table 2

PRODUCTIVITY RESULTS: US SAMPLE

Year	Output Quantity Index		Input Quantity Index		TFP Index		O&M PFP Index		
	Geometric Decay	**COS**	**Geometric Decay**	**COS**	**Geometric Decay**	**COS**	**Geometric Decay**	**COS**	**US Private Business Sector**
1994	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	93.7
1995	1.016	1.016	1.004	1.001	1.012	1.015	1.024	1.025	93.5
1996	1.038	1.039	1.005	1.000	1.033	1.039	1.057	1.058	95.1
1997	1.052	1.053	0.989	0.982	1.064	1.073	1.127	1.128	96.0
1998	1.055	1.059	0.984	0.973	1.072	1.088	1.165	1.169	97.5
1999	1.083	1.086	0.987	0.976	1.098	1.113	1.196	1.199	98.7
2000	1.106	1.110	0.992	0.980	1.115	1.133	1.200	1.204	100.0
2001	1.111	1.120	0.990	0.978	1.123	1.146	1.231	1.241	100.2
2002	1.118	1.125	0.993	0.982	1.126	1.145	1.240	1.248	101.8
2003	1.127	1.135	1.002	0.991	1.125	1.145	1.239	1.247	104.7
2004	1.137	1.147	1.010	0.994	1.125	1.154	1.239	1.250	107.7
Average Annual Growth Rate **1994-2004**	**1.28%**	**1.37%**	**0.10%**	**-0.06%**	**1.18%**	**1.43%**	**2.14%**	**2.23%**	**1.39%**

FIGURE 1: TFP RESULTS FOR US GAS DISTRIBUTION SAMPLE

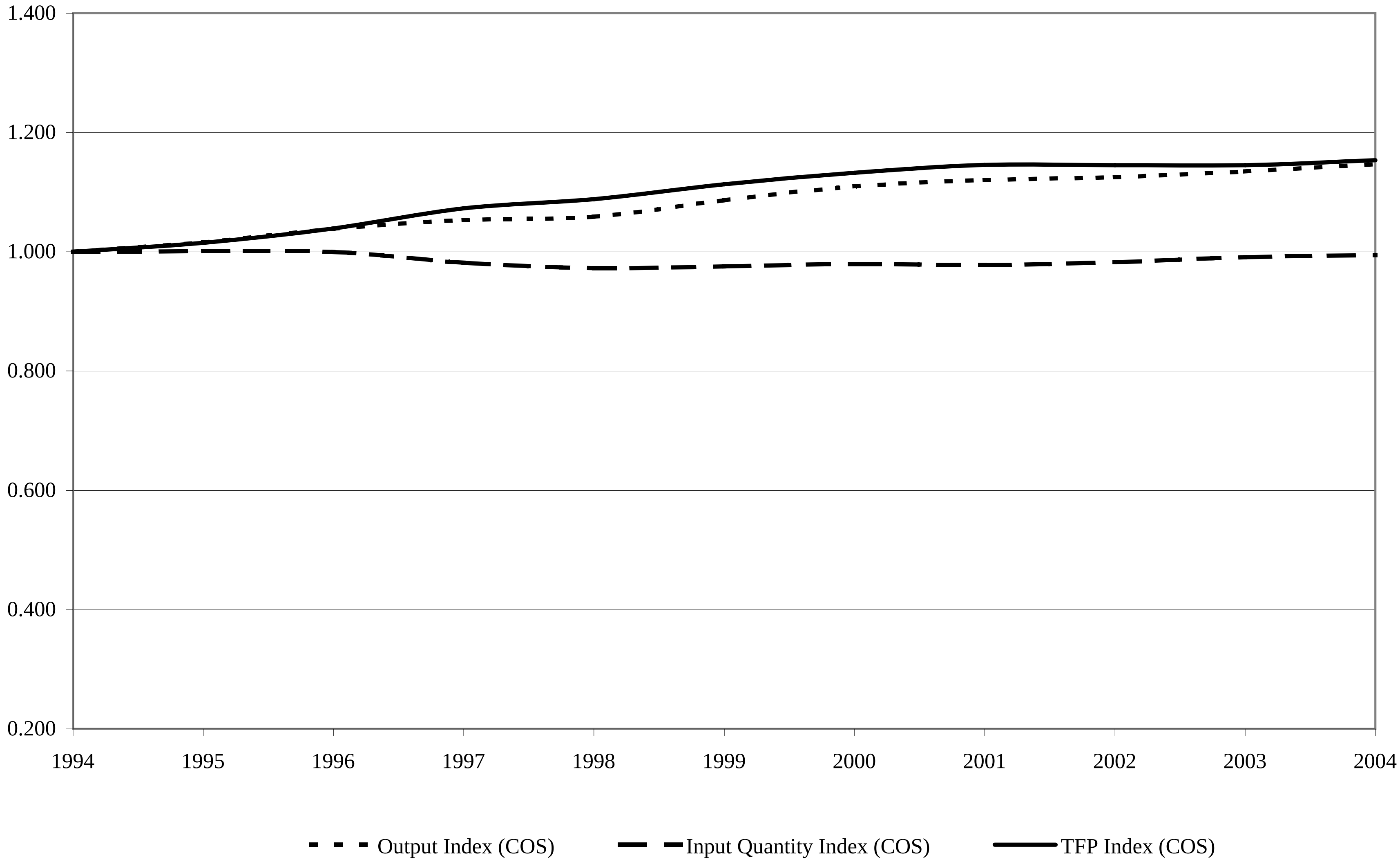

Table 3 presents some details of the input quantity trends of the sampled US utilities. It can be seen that the quantity trends of different kinds of inputs varied considerably. The quantity of capital grew at a 0.49% annual pace that was modestly above that of the summary input quantity index. Usage of O&M inputs thus grew at a considerably slower pace on balance. Use of labour declined materially whereas use of materials and services rose briskly. These findings may reflect some substitution of M&S inputs for labour. It may also reflect greater reliance on the services of affiliated companies.

Table 4 presents some details of the output quantity trends of the sampled US utilities. It can be seen that the number of customers grew at a 1.63% average annual pace. The volume of residential and commercial deliveries grew at a much slower 0.60% average annual pace. The average use of gas by residential and commercial customers thus fell by about 1% annually.[26] 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 in fact at a 0.10% average annual rate. Recalling the 1.37% average annual growth in the output index with elasticity weights, the resultant output quantity trend differential averaged -1.27%.[27]

Enbridge

Table 5 presents results of the TFP indexes for Enbridge and Union. Considering Enbridge first, we find using the COS approach to capital costing that its 0.71% average annual TFP growth from 2000 to 2005 was a little below the US norm. The 2.83% average annual pace of output growth was more than double the US norm. This reflects in large measure the brisk expansion of the Toronto and Ottawa metropolitan areas. Input quantity growth averaged 2.12% annually.

In marked contrast with the US trend, the partial factor productivity index for the use of O&M inputs by Enbridge *fell* at a 0.70% average annual pace. PFP fell by more than 11% in 2003 and did not subsequently regain much of the lost ground. The year 2003 was the first following the conclusion of the company's targeted IR plan for O&M inputs. Thus, there is no evidence that this plan produced lasting benefits for Enbridge customers.

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[26] 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.

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

Table 3

INPUT QUANTITY INDEXES: US GAS DISTRIBUTION SAMPLE

	Summary Index		Input Quantity Subindexes			
Year	**Geometric Decay**	**COS**	**Labor**	**Materials & Services**	**Capital - Geometric Decay**	**Capital - COS**
1994	1.000	1.000	1.000	1.000	1.000	1.000
1995	1.004	1.001	0.928	1.132	1.012	1.009
1996	1.005	1.000	0.914	1.131	1.022	1.016
1997	0.989	0.982	0.898	1.038	1.030	1.023
1998	0.984	0.973	0.855	1.058	1.037	1.026
1999	0.987	0.976	0.855	1.064	1.041	1.030
2000	0.992	0.980	0.790	1.198	1.046	1.033
2001	0.990	0.978	0.742	1.261	1.049	1.037
2002	0.993	0.982	0.780	1.192	1.054	1.045
2003	1.002	0.991	0.782	1.215	1.062	1.051
2004	1.010	0.994	0.740	1.314	1.069	1.050
Average Annual Growth Rate **1994-2004**	**0.10%**	**-0.06%**	**-3.00%**	**2.73%**	**0.67%**	**0.49%**

Table 4

OUTPUT QUANTITY INDEXES: US GAS DISTRIBUTION SAMPLE

	Summary Output			Quantity Subindexes		
	Cost Elasticity Weights		Fixed Revenue Weights	Customer Numbers	Residential and Commercial Deliveries	Other Deliveries
Year	**Geometric Decay**	**COS**				
1994	1.000	1.000	1.000	1.000	1.000	1.000
1995	1.016	1.016	1.011	1.019	1.019	0.982
1996	1.038	1.039	1.021	1.037	1.039	0.959
1997	1.052	1.053	1.027	1.056	1.054	0.930
1998	1.055	1.059	1.004	1.075	1.027	0.871
1999	1.083	1.086	1.033	1.095	1.054	0.913
2000	1.106	1.110	1.056	1.113	1.080	0.933
2001	1.111	1.120	1.008	1.137	1.035	0.814
2002	1.118	1.125	1.025	1.148	1.053	0.830
2003	1.127	1.135	1.017	1.163	1.083	0.737
2004	1.137	1.147	1.011	1.178	1.062	0.737
Average Annual Growth Rate **1994-2004**	**1.28%**	**1.37%**	**0.10%**	**1.63%**	**0.60%**	**-3.05%**

Table 5

PRODUCTIVITY RESULTS: ONTARIO

	Output Quantity Index - Cost Elasticity				Input Quantity Index				TFP Index				O&M PFP Index[1]	
Year	**GD Capital Cost**		**COS Capital Cost**		**GD Capital Cost**		**COS Capital Cost**		**GD Capital Cost**		**COS Capital Cost**		**COS Weights**	
	Union	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**	**Enbridge**
1999	1.000		1.000		1.000		1.000		1.000		1.000		1.000	
2000	1.020	1.000	1.020	1.000	0.980	1.000	0.977	1.000	1.041	1.000	1.044	1.000	1.133	1.000
2001	1.021	1.026	1.022	1.027	0.983	1.029	0.981	1.028	1.039	0.997	1.042	0.999	1.120	0.967
2002	1.062	1.057	1.063	1.059	1.014	1.023	1.015	1.021	1.047	1.033	1.048	1.038	1.063	1.059
2003	1.072	1.091	1.073	1.093	1.014	1.075	1.006	1.076	1.058	1.015	1.067	1.016	1.119	0.944
2004	1.093	1.122	1.097	1.126	0.998	1.092	0.990	1.095	1.095	1.028	1.109	1.028	1.163	0.944
2005	1.118	1.147	1.123	1.152	0.983	1.101	0.979	1.112	1.137	1.042	1.147	1.036	1.210	0.965
Average Annual Growth Rate														
1999-2005	**1.85%**	NA	**1.93%**	NA	**-0.28%**	NA	**-0.35%**	NA	**2.14%**	NA	**2.28%**	NA	**3.17%**	NA
2000-2005	**1.83%**	**2.74%**	**1.92%**	**2.83%**	**0.07%**	**1.92%**	**0.05%**	**2.12%**	**1.76%**	**0.83%**	**1.87%**	**0.71%**	**1.31%**	**-0.70%**

[1]These indexes were computed using output indexes reflecting COS capital costing.

Tables 6 and 7 present some details of the input and output quantity trends of Enbridge. It can be seen that the input growth pattern was quite different from the US norm. The 1.50% trend in the capital quantity using COS costing was well below the trend in the summary input quantity index, instead of being modestly above it, as in the US case.
The TFP index for Enbridge that we calculated using GD capital costing had a 0.83% average annual growth rate over the 2000-2005 period— quite similar to the pace we calculated using COS costing.

Union

Table 5 reveals that the TFP growth of Union using COS costing averaged 1.87% growth per annum, well above the US norm and more than double that of Enbridge. The 1.92% average annual pace of output growth was well below that of Enbridge but well above the US norm. Input use was virtually unchanged, with a 0.05% average annual pace of input index growth that was similar to the US trend. Union's PFP index for O&M inputs averaged 1.31% annual growth, far below the US trend but well above that of Enbridge.
The TFP index for Union that we calculated using GD capital costing exhibited 1.76% average annual growth over the 2000-2005 period. This is similar to the pace that we calculated using COS costing. Table 6 shows that the decline in input usage (using COS costing) was due to a 0.58% average annual decline in the use of labour and a 0.26% decline in the use of capital.

A side calculation revealed that the trends in the quantities of capital used in distribution and transmission are fairly similar. This suggests that Union's TFP growth isn't markedly higher than that of Enbridge due to an extraordinary decline in Union's transmission rate base. It should also be noted that PEG has long had difficulty identifying statistically any special impact on gas utility cost management that results from transmission and storage operations. There was for this reason no compelling need to take transmission and storage into account in choosing Union's peer group.

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	0.980	1.000	0.977	1.000	0.876	0.549	0.936	1.500	1.459	NA	1.008	1.000	1.006	1.000
2001	0.983	1.029	0.981	1.028	0.875	0.557	0.968	1.627	1.251	NA	1.012	1.017	1.013	1.015
2002	1.014	1.023	1.015	1.021	0.903	0.475	1.144	1.596	1.346	NA	1.017	1.031	1.017	1.030
2003	1.014	1.075	1.006	1.076	0.881	0.517	1.075	1.892	1.874	NA	1.020	1.045	1.007	1.041
2004	0.998	1.092	0.990	1.095	0.828	0.563	1.120	1.907	1.700	NA	1.009	1.056	0.997	1.053
2005	0.983	1.101	0.979	1.112	0.851	0.584	1.040	1.880	1.601	NA	0.998	1.068	0.993	1.078
Average Annual Growth Rate														
1999-2005	**-0.28%**	NA	**-0.35%**	NA	**-2.69%**	NA	**0.65%**	NA	**7.84%**	NA	**-0.04%**	NA	**-0.11%**	NA
2000-2005	**0.07%**	**1.92%**	**0.05%**	**2.12%**	**-0.58%**	**1.25%**	**2.11%**	**4.51%**	**1.86%**	NA	**-0.19%**	**1.31%**	**-0.26%**	**1.50%**

Table 7

OUTPUT QUANTITY INDEXES: ONTARIO

	Summary Output Quantity Indexes						Output Quantity Subindexes[1]					
Year	Cost Elasticity - GD Capital Cost		Cost Elasticity Weights - COS Capital Cost		Fixed Revenue Weights		Customers		Residential & Commercial Volume		Other Volume	
	Union	Enbridge	Union	Enbridge	Union	Enbridge	Union	Enbridge	Union[2]	Enbridge[3]	Union	Enbridge
1999	1.000		1.000		1.000		1,103,636		5,022		29,613	
2000	1.020	1.000	1.020	1.000	1.013	1.000	1,123,523	1,464,738	5,125	8,618	30,525	3,166
2001	1.021	1.026	1.022	1.027	1.017	1.020	1,146,376	1,519,039	5,066	8,747	27,635	2,905
2002	1.062	1.057	1.063	1.059	1.051	1.029	1,171,277	1,566,710	5,253	8,725	32,023	2,983
2003	1.072	1.091	1.073	1.093	1.073	1.083	1,195,115	1,622,016	5,365	9,250	30,082	2,960
2004	1.093	1.122	1.097	1.126	1.072	1.092	1,224,276	1,676,380	5,194	9,241	31,169	2,914
2005	1.118	1.147	1.123	1.152	1.076	1.106	1,248,510	1,724,716	5,289	9,325	32,632	2,799
Average Annual Growth Rate												
1999-2005	**1.85%**	NA	**1.93%**	NA	**1.22%**	NA	**2.06%**	NA	**0.86%**	NA	**1.62%**	NA
2000-2005	**1.83%**	**2.74%**	**1.92%**	**2.83%**	**1.20%**	**2.02%**	**2.11%**	**3.27%**	**0.63%**	**1.58%**	**1.33%**	**-2.46%**

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

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

[3]Residential and commercial volume (Rates 1, 6 and 100) was weather normalized by PEG.

Productivity Differentials

A productivity differential was noted in Section 2 to be the difference between the trends in the productivity growth of the utility industry and the economy. The productivity trend of the industry in such a calculation is conventionally based largely or entirely on the productivity index trends of other utilities. This is often computed using the productivity trends of utilities in the same region as the subject utility.[28] This approach isn't feasible in the case of Enbridge and Union, for several reasons.

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

Research of two kinds was accordingly undertaken, using US data, to assess the normal pace of TFP growth for companies facing the business conditions of Union and Enbridge. Both approaches made use of our 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 opportunities to realize economies of scale that were similar to those facing Enbridge and Union. The opportunity for a gas distributor to realize scale economies depends on the pace of its output growth and on the incremental scale economies that can result from output growth.

Results of this peer group analysis for the GD and COS approaches to capital costing are reported for Enbridge and Union in Tables 8a and 8b and 9a and 9b, respectively. Each table contains TFP trends and an estimate of realized scale economies for all sampled US

[28] 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 8a

CHOOSING TFP PEERS FOR ENBRIDGE: GEOMETRIC DECAY [1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Enbridge	Peer
Arithmetic Sample Average[3]	1.04%	0.11%	-0.51%	
Peer Average	**1.99%**	0.32%	-0.31%	
Enbridge	0.83%	0.72%		
Washington Gas Light	**2.08%**	0.46%	-0.17%	1
East Ohio Gas	**2.00%**	0.41%	-0.22%	1
Pacific Gas & Electric	**2.11%**	0.40%	-0.23%	1
Northern Illinois Gas	**1.18%**	0.29%	-0.33%	1
Southern California Gas	**1.52%**	0.28%	-0.35%	1
Mountain Fuel Supply	**1.89%**	0.25%	-0.38%	1
Southwest Gas	**2.63%**	0.24%	-0.38%	1
Nstar Gas	**2.54%**	0.23%	-0.40%	1
Atlanta Gas Light	**1.32%**	0.19%	-0.44%	
New Jersey Natural	**1.77%**	0.19%	-0.44%	
Consolidated Edison	**0.87%**	0.17%	-0.46%	
North Shore Gas	**1.97%**	0.17%	-0.46%	
Wisconsin Gas	**1.57%**	0.16%	-0.47%	
Niagara Mohawk	**0.98%**	0.15%	-0.48%	
Illinois Power	**1.98%**	0.15%	-0.48%	
Baltimore Gas and Electric	**1.29%**	0.13%	-0.50%	
Northwest Natural Gas	**1.94%**	0.13%	-0.50%	
Washington Natural Gas	**0.95%**	0.12%	-0.51%	
Consumers Power	**0.46%**	0.10%	-0.53%	
PECO	**0.81%**	0.09%	-0.54%	
Rochester Gas and Electric	**0.79%**	0.07%	-0.55%	
PG Energy	**0.91%**	0.05%	-0.58%	
Connecticut Energy	**1.19%**	0.05%	-0.58%	
People's Natural Gas	**0.30%**	0.03%	-0.60%	
Peoples Gas Light & Coke	**0.14%**	0.03%	-0.60%	
Madison Gas & Electric	**0.74%**	0.02%	-0.60%	
Public Service of NC	**0.41%**	0.01%	-0.62%	
Wisconsin Power & Light	**1.22%**	0.01%	-0.62%	
Louisville Gas & Electric	**-0.08%**	-0.01%	-0.63%	
San Diego Gas & Electric	**-0.59%**	-0.01%	-0.64%	
Connecticut Natural Gas	**-0.27%**	-0.03%	-0.66%	
Orange and Rockland	**-1.10%**	-0.05%	-0.68%	
Central Hudson Gas & Electric	**2.00%**	-0.06%	-0.69%	
Cascade Natural Gas	**2.70%**	-0.08%	-0.70%	
Alabama Gas	**-2.11%**	-0.08%	-0.71%	
Public Service Electric & Gas	**-0.61%**	-0.13%	-0.76%	

[1] Results are calculated using the geometric decay approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

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

Table 8b

CHOOSING TFP PEERS FOR ENBRIDGE: COS[1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Enbridge	Peer
Arithmetic Sample Average[3]	1.29%	0.15%	-0.49%	
Peer Average	**2.13%**	0.38%	-0.27%	
Enbridge	0.71%	0.65%		
Washington Gas Light	**2.61%**	0.60%	-0.05%	1
East Ohio Gas	**2.44%**	0.52%	-0.13%	1
Pacific Gas & Electric	**2.27%**	0.41%	-0.24%	1
Northern Illinois Gas	**1.58%**	0.40%	-0.25%	1
Southern California Gas	**1.74%**	0.30%	-0.35%	1
Mountain Fuel Supply	**2.16%**	0.29%	-0.36%	1
Nstar Gas	**2.62%**	0.27%	-0.38%	1
Niagara Mohawk	**1.62%**	0.26%	-0.39%	1
Southwest Gas	**2.90%**	0.25%	-0.40%	
New Jersey Natural	**1.83%**	0.22%	-0.43%	
North Shore Gas	**2.21%**	0.21%	-0.44%	
Atlanta Gas Light	**1.45%**	0.21%	-0.44%	
Baltimore Gas and Electric	**1.95%**	0.21%	-0.44%	
Illinois Power	**2.44%**	0.19%	-0.46%	
Wisconsin Gas	**1.80%**	0.19%	-0.46%	
Consumers Power	**0.82%**	0.18%	-0.46%	
Consolidated Edison	**0.86%**	0.18%	-0.47%	
Peoples Gas Light & Coke	**0.63%**	0.15%	-0.49%	
Washington Natural Gas	**1.04%**	0.14%	-0.51%	
Northwest Natural Gas	**2.09%**	0.14%	-0.51%	
PECO	**1.19%**	0.13%	-0.52%	
Rochester Gas and Electric	**0.94%**	0.10%	-0.55%	
People's Natural Gas	**0.69%**	0.08%	-0.56%	
PG Energy	**1.15%**	0.07%	-0.58%	
Connecticut Energy	**1.27%**	0.06%	-0.59%	
Madison Gas & Electric	**0.98%**	0.03%	-0.61%	
Connecticut Natural Gas	**0.18%**	0.02%	-0.63%	
Wisconsin Power & Light	**1.40%**	0.02%	-0.63%	
Louisville Gas & Electric	**0.27%**	0.02%	-0.63%	
Public Service of NC	**0.41%**	0.01%	-0.63%	
San Diego Gas & Electric	**-0.47%**	-0.01%	-0.65%	
Central Hudson Gas & Electric	**2.06%**	-0.05%	-0.69%	
Orange and Rockland	**-0.93%**	-0.06%	-0.70%	
Cascade Natural Gas	**2.95%**	-0.08%	-0.73%	
Alabama Gas	**-2.09%**	-0.08%	-0.73%	
Public Service Electric & Gas	**-0.51%**	-0.11%	-0.76%	

[1] Results are calculated using the COS approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

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

Table 9a

CHOOSING TFP PEERS FOR UNION: GEOMETRIC DECAY[1]

Company	TFP	Expected Scale Economies[2] Company	Expected Scale Economies[2] vs. Union	Peer
Arithmetic Sample Average[3]	1.04%	0.11%	-0.16%	
Peer Average	**1.88%**	0.28%	0.00%	
Union	1.76%	0.27%		
Washington Gas Light	**2.08%**	0.46%	0.18%	
East Ohio Gas	**2.00%**	0.41%	0.14%	1
Pacific Gas & Electric	**2.11%**	0.40%	0.12%	1
Northern Illinois Gas	**1.18%**	0.29%	0.02%	1
Southern California Gas	**1.52%**	0.28%	0.00%	1
Mountain Fuel Supply	**1.89%**	0.25%	-0.03%	1
Southwest Gas	**2.63%**	0.24%	-0.03%	1
Nstar Gas	**2.54%**	0.23%	-0.04%	1
Atlanta Gas Light	**1.32%**	0.19%	-0.08%	1
New Jersey Natural	**1.77%**	0.19%	-0.09%	1
Consolidated Edison	**0.87%**	0.17%	-0.11%	
North Shore Gas	**1.97%**	0.17%	-0.11%	
Wisconsin Gas	**1.57%**	0.16%	-0.12%	
Niagara Mohawk	**0.98%**	0.15%	-0.13%	
Illinois Power	**1.98%**	0.15%	-0.13%	
Baltimore Gas and Electric	**1.29%**	0.13%	-0.14%	
Northwest Natural Gas	**1.94%**	0.13%	-0.15%	
Washington Natural Gas	**0.95%**	0.12%	-0.16%	
Consumers Power	**0.46%**	0.10%	-0.17%	
PECO	**0.81%**	0.09%	-0.19%	
Rochester Gas and Electric	**0.79%**	0.07%	-0.20%	
PG Energy	**0.91%**	0.05%	-0.23%	
Connecticut Energy	**1.19%**	0.05%	-0.23%	
People's Natural Gas	**0.30%**	0.03%	-0.24%	
Peoples Gas Light & Coke	**0.14%**	0.03%	-0.24%	
Madison Gas & Electric	**0.74%**	0.02%	-0.25%	
Public Service of NC	**0.41%**	0.01%	-0.26%	
Wisconsin Power & Light	**1.22%**	0.01%	-0.27%	
Louisville Gas & Electric	**-0.08%**	-0.01%	-0.28%	
San Diego Gas & Electric	**-0.59%**	-0.01%	-0.29%	
Connecticut Natural Gas	**-0.27%**	-0.03%	-0.30%	
Orange and Rockland	**-1.10%**	-0.05%	-0.33%	
Central Hudson Gas & Electric	**2.00%**	-0.06%	-0.34%	
Cascade Natural Gas	**2.70%**	-0.08%	-0.35%	
Alabama Gas	**-2.11%**	-0.08%	-0.36%	
Public Service Electric & Gas	**-0.61%**	-0.13%	-0.41%	

[1] Results are calculated using the geometric decay approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

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

Table 9b

CHOOSING TFP PEERS FOR UNION: COS[1]

Company	TFP	Expected Scale Economies[2] Company	vs. Union	Peer
Arithmetic Sample Average[3]	1.29%	0.15%	-0.13%	
Peer Average	**2.04%**	0.28%	0.00%	
Union	1.87%	0.28%		
Washington Gas Light	**2.61%**	0.60%	0.32%	
East Ohio Gas	**2.44%**	0.52%	0.23%	
Pacific Gas & Electric	**2.27%**	0.41%	0.13%	1
Northern Illinois Gas	**1.58%**	0.40%	0.11%	1
Southern California Gas	**1.74%**	0.30%	0.02%	1
Mountain Fuel Supply	**2.16%**	0.29%	0.01%	1
Nstar Gas	**2.62%**	0.27%	-0.01%	1
Niagara Mohawk	**1.62%**	0.26%	-0.02%	1
Southwest Gas	**2.90%**	0.25%	-0.03%	1
New Jersey Natural	**1.83%**	0.22%	-0.06%	1
North Shore Gas	**2.21%**	0.21%	-0.07%	1
Atlanta Gas Light	**1.45%**	0.21%	-0.07%	1
Baltimore Gas and Electric	**1.95%**	0.21%	-0.07%	
Illinois Power	**2.44%**	0.19%	-0.09%	
Wisconsin Gas	**1.80%**	0.19%	-0.10%	
Consumers Power	**0.82%**	0.18%	-0.10%	
Consolidated Edison	**0.86%**	0.18%	-0.10%	
Peoples Gas Light & Coke	**0.63%**	0.15%	-0.13%	
Washington Natural Gas	**1.04%**	0.14%	-0.14%	
Northwest Natural Gas	**2.09%**	0.14%	-0.14%	
PECO	**1.19%**	0.13%	-0.15%	
Rochester Gas and Electric	**0.94%**	0.10%	-0.18%	
People's Natural Gas	**0.69%**	0.08%	-0.20%	
PG Energy	**1.15%**	0.07%	-0.21%	
Connecticut Energy	**1.27%**	0.06%	-0.22%	
Madison Gas & Electric	**0.98%**	0.03%	-0.25%	
Connecticut Natural Gas	**0.18%**	0.02%	-0.26%	
Wisconsin Power & Light	**1.40%**	0.02%	-0.26%	
Louisville Gas & Electric	**0.27%**	0.02%	-0.26%	
Public Service of NC	**0.41%**	0.01%	-0.27%	
San Diego Gas & Electric	**-0.47%**	-0.01%	-0.29%	
Central Hudson Gas & Electric	**2.06%**	-0.05%	-0.33%	
Orange and Rockland	**-0.93%**	-0.06%	-0.34%	
Cascade Natural Gas	**2.95%**	-0.08%	-0.36%	
Alabama Gas	**-2.09%**	-0.08%	-0.36%	
Public Service Electric & Gas	**-0.51%**	-0.11%	-0.40%	

[1] Results are calculated using the COS approach to capital costing

[2] Formula for expected scale economies is (1 - sumE_i) x growth Y^E where E_i is the estimated elasticity with respect to the growth of output i and change in Y^E is the growth of the elasticity weighted output index. The elasticity estimates vary by company

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

companies. Results for the peer group companies are shaded. Over the full 1994-2004 sample period it can be seen using COS capital costing that the Enbridge peer group averaged 2.13% TFP growth. The development of a proper peer group proved difficult inasmuch as our research found that Enbridge had more opportunity to realize scale economies than any sampled US company due to its peculiar combination of large operating scale and rapid output growth.[29] The Union peer group averaged 2.04% annual TFP growth. Similar numbers were obtained using GD capital costing.

The TFP trends of the individual utilities support some key findings of our econometric research. For example, the fact that the peer group TFP trends for Enbridge and Union, with their outsized scale economy potential, were well above the US sample average supports our econometric finding that scale economies are an important peer group criterion. It is also noteworthy that larger companies in the sample generally had more rapid TFP growth. This supports our finding that the incremental scale economies from output growth are generally greater for large utilities than for small ones.

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. In this exercise, we assigned each company the estimated parametric trend from the appropriate econometric model. We then added this to each company's estimated long term scale economies resulting from the growth in their output during the sample period. This depends on the availability of incremental scale economies from growth in output and on the trend in output growth. We measure the opportunity for incremental scale economies of each company as 1 minus the sum of the econometric estimates of its estimated output elasticities. We measure output growth as the average annual growth in each company's weather normalized, elasticity-weighted output index from 2000 to 2005. The expected scale economies are the product of these two terms. Results of this analysis are reported in Table 10. It can be seen that using COS capital costing the TFP trend targets calculated in this way for Enbridge and Union are 2.10% and 1.73% respectively. Numbers are a little lower using GD costing.

[29] This was due to an unusual combination of large operating scale and rapid output growth.

Table 10

TFP GROWTH PROJECTIONS FROM ECONOMETRIC RESEARCH

	Geometric Decay Capital Costing		COS Capital Costing	
	Enbridge	**Union**	**Enbridge**	**Union**
Sample Years	2000-2005	2000-2005	2000-2005	2000-2005
Elasticity Estimates				
Customers [A]	*0.657*	*0.638*	*0.713*	*0.692*
Residential & Commercial Deliveries [B]	*0.016*	*0.104*	*0.000*	*0.049*
Other Deliveries [C]	*0.063*	*0.109*	*0.059*	*0.113*
Weights				
Customers [D]	89.27%	74.97%	92.36%	81.03%
Residential & Commercial Deliveries [E]	2.17%	12.22%	0.00%	5.74%
Other Deliveries [F]	8.56%	12.81%	7.64%	13.23%
Subindex Growth				
Customer [G]	3.27%	2.11%	3.27%	2.11%
Residential & Commercial Delivery [H]	1.58%	0.63%	1.58%	0.63%
Other Delivery [I]	-2.46%	1.33%	-2.46%	1.33%
Sum of Output Elasticities [J=A+B+C]	0.736	0.851	0.772	0.854
Output Growth (elasticity weighted) [K=D*G+E*H+F*I]	2.74%	1.83%	2.83%	1.92%
Technological Change [L]	**1.19%**	**1.19%**	**1.45%**	**1.45%**
Returns to Scale [M=(1-J)*K]	**0.72%**	**0.27%**	**0.65%**	**0.28%**
TFP Projection [L + M]	**1.91%**	**1.46%**	**2.10%**	**1.73%**

In comparing the suitability of these methods, we find that the econometric approach is less sensitive to the random variations in the TFP trends of the comparatively small peer groups. A suitable peer group for Enbridge is, in any event, unavailable. We therefore recommend the use of the econometric projections to establish the TFP growth of both companies. The resultant targets are thus 2.10% and 1.73% for Enbridge and Union, respectively.

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

The econometric models also provide us with an estimate of the effect of cast iron replacement on TFP growth. This could potentially be added to the TFP trend target for Enbridge. As discussed in Section 3.3.2 we found that cast iron mains *raise* total cost. This finding implies that a reduction in cast iron *accelerates* TFP growth in the *long* run. However, the *short* term effect on TFP growth may be different since the O&M cost savings may be offset initially by the cost impact of the installation of new pipe. As an extra check, we regressed the growth in the TFP of our sampled US utilities (using both approaches to capital costing) on the change in their cast iron reliance using data for the sample period. Using each approach, the estimated effect of reduced reliance on cost was negative (suggesting that it *raises* cost), but 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.

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 1998-2005 to be a sensible input price comparison period when COS capital costing is used. The MFP trend of the Canadian economy was 1.21% during this period. The indicated productivity differential for Enbridge using COS capital costing is thus 0.89% (2.10 – 1.21). The productivity differential for Union is thus 0.52% (1.73 – 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, the actual volumes per customer for the period 2000-2005 by service class as well as weather normalized treatments that were calculated independently by PEG and the companies. For Enbridge, we present the volumes approved in rate cases as well as the company's calculations of revenue normalized volumes. We also report weather normalized volumes/customer that the company presented at a stakeholder conference last fall. Company figures for Union were calculated using weather normalized volumes provided to PEG by the company.

Inspecting the tables it is evident that, using the weather normalization procedures of both PEG and the companies, there were material declines in average use for all of the main rate classes with residential load. Using the PEG weather normalizations the average use declines appeared to be greater for Union than for Enbridge.[30] However they are normalized, it is notable that space heating loads constitute a smaller share of Union's deliveries. Thus, it is not clear *a priori* which company should have the larger AU.

It is also interesting that the weather normalized trends computed by PEG were similar to the company's in the case of Union but not in the case of Enbridge. Moreover, the figures calculated by PEG suggest average use declines for Enbridge that are considerably less severe than those calculated by the company. These discrepancies may reflect the fact that PEG, like Union but in contrast to Enbridge, used normalization methods in which the impacts of heating degree days ("HDDs") on delivery volumes are estimated econometrically.

The average use factor was explained in Section 2 to be the difference between the growth trends in the output quantity indexes with revenue and elasticity weights. For Enbridge and Union, the output growth differentials using COS costing to calculate elasticities were -0.81% (2.02-2.83) and -0.72% (1.20-1.92) respectively.[31] The AU for

[30] 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 Enbridge reported volumes on a *fiscal* year whereas Union reported on a *calendar* year basis.

[31] The analogous result for our U.S. sample is -1.27. However, this calculation is not made with the same precision due to data limitations.

Table 11a

Volume Per Customer Trends: Enbridge

Rate 1 (Residential)

Year	Volumes				Customers		Volume Per Customer				
	Actual	Approved Rate Case Forecast	Normalized		Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized		Enbridge Stakeholder Presentation
			PEG	Enbridge					PEG	Enbridge	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]=1000*[A]/[E]	[H]=[B]/[F]	[I]=1000*[C]/[E]	[J]=1000*[D]/[E]	
2000	4,008	4,266,360	4,116	4,283	1,325,938	1,328,659	3.023	3.211	3.104	3.230	3,043
2001	4,228	4,163,327	4,185	4,147	1,377,459	1,373,517	3.070	3.031	3.038	3.010	2,940
2002	4,002	4,203,965	4,222	4,233	1,423,525	1,418,180	2.812	2.964	2.966	2.973	2,929
2003	4,735	4,241,724	4,512	4,242	1,476,603	1,468,966	3.207	2.888	3.056	2.873	2,900
2004	4,596	4,241,724	4,544	4,342	1,529,297	1,468,966	3.006	2.888	2.971	2.839	2,850
2005	4,620	4,626,802	4,598	4,548	1,575,322	1,568,544	2.932	2.950	2.919	2.887	2,779
2000-2005	**2.84%**	**1.62%**	**2.22%**	**1.20%**	**3.45%**	**3.32%**	**-0.61%**	**-1.70%**	**-1.23%**	**-2.25%**	**-1.82%**

Rate 6 (General Service)

Year	Volumes				Customers		Volume Per Customer				
	Actual	Approved Rate Case Forecast	Normalized		Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized		Enbridge Stakeholder Presentation
			PEG	Enbridge					PEG	Enbridge	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]=1000*[A]/[E]	[H]=[B]/[F]	[I]=1000*[C]/[E]	[J]=1000*[D]/[E]	
2000	2,999	3,175,841	3,076	3,219	136,025	138,575	22.050	22.918	22.612	23.663	22,138
2001	3,200	3,148,327	3,169	3,139	138,779	138,443	23.058	22.741	22.835	22.619	21,930
2002	2,932	3,200,782	3,083	3,110	140,351	144,102	20.888	22.212	21.968	22.156	21,785
2003	3,485	3,119,887	3,330	3,095	142,656	143,293	24.430	21.773	23.343	21.694	21,816
2004	3,314	3,119,887	3,278	3,110	144,331	143,293	22.959	21.773	22.711	21.548	21,527
2005	3,327	3,324,324	3,312	3,271	146,672	147,475	22.681	22.542	22.582	22.301	21,131
2000-2005	**2.07%**	**0.91%**	**1.48%**	**0.32%**	**1.51%**	**1.25%**	**0.56%**	**-0.33%**	**-0.03%**	**-1.19%**	**-0.93%**

Rate 100 (Large Volume Firm)

Year	Volumes				Customers		Volume Per Customer				
	Actual	Approved Rate Case Forecast	Normalized		Actual	Approved Rate Case Forecast	Actual	Approved Rate Case Forecast	Normalized		Enbridge Stakeholder Presentation
			PEG	Enbridge					PEG	Enbridge	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]=1000*[A]/[E]	[H]=[B]/[F]	[I]=1000*[C]/[E]	[J]=1000*[D]/[E]	
2000	1,395	1,480,125	1,427	NA	2,019	1,993	691.035	742.662	706.625	NA	NA
2001	1,405	1,425,997	1,393	NA	2,043	1,911	687.714	746.205	681.809	NA	NA
2002	1,358	1,393,737	1,420	NA	2,087	1,956	650.455	712.544	680.179	NA	NA
2003	1,466	1,394,623	1,408	NA	2,029	2,007	722.425	694.822	693.867	NA	NA
2004	1,433	1,394,623	1,419	NA	2,069	2,007	692.412	694.822	685.783	NA	NA
2005	1,421	1,401,603	1,415	NA	2,065	1,985	687.893	706.127	685.244	NA	NA
2000-2005	**0.36%**	**-1.09%**	**-0.16%**	**NA**	**0.45%**	**-0.08%**	**-0.09%**	**-1.01%**	**-0.61%**	**NA**	**NA**

Table 11b

Volume Per Customer Trends: Union

Rate M2: General Service South

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

Year	Volumes			Customers	Volume Per Customer[1]			
	Actual	Weather Normalized		Actual	Actual	Weather Normalized		Union Stakeholder Presentation Weather Normalized[2]
		PEG	Union			PEG	Union	
	[A]	[B]	[C]	[D]	[E]=1000*[A]/[D]	[F]=1000*[B]/[D]	[G]=1000*[C]/[D]	
1999	3,748	3,799		836,601				NA
2000	3,898	3,822	3,897	848,719	4.593	4.503	4.592	NA
2001	3,668	3,816	3,902	869,021	4.221	4.391	4.490	4.577
2002	3,911	3,967	4,054	890,233	4.393	4.457	4.554	4.600
2003	4,164	4,038	3,948	911,282	4.569	4.431	4.332	4.521
2004	3,945	3,917	3,976	935,557	4.217	4.187	4.250	4.334
2005	4,028	4,003	4,015	956,004	4.213	4.187	4.200	4.255
2000-2005[3]	**0.66%**	**0.93%**	**0.60%**	**2.38%**	**-1.72%**	**-1.45%**	**-1.78%**	**-1.82%**

Rate 01: General Service North + East

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

Year	Volumes			Customers	Volume Per Customer[1]			
	Actual	Weather Normalized		Actual	Actual	Weather Normalized		Union Stakeholder Presentation Weather Normalized[2]
		PEG	Union			PEG	Union	
	[A]	[B]	[C]	[D]	[E]=1000*[A]/[D]	[F]=1000*[B]/[D]	[G]=1000*[C]/[D]	
1999	844	861		263,686				NA
2000	945	924	959	271,537	3.480	3.403	3.532	NA
2001	855	889	932	274,087	3.119	3.242	3.400	3.183
2002	912	906	939	277,588	3.285	3.265	3.383	3.371
2003	957	940	921	280,373	3.413	3.353	3.285	3.400
2004	919	900	926	285,201	3.222	3.154	3.247	3.243
2005	886	897	921	288,801	3.068	3.105	3.189	3.179
2000-2005	**-1.29%**	**-0.60%**	**-0.81%**	**1.23%**	**-2.52%**	**-1.84%**	**-2.04%**	**-0.03%**

Rate 10: (General Service North + East)

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

Year	Volumes			Customers	Volume Per Customer[1]			
	Actual	Weather Normalized		Actual	Actual	Weather Normalized		Union Stakeholder Presentation Weather Normalized[2]
		PEG	Union			PEG	Union	
	[A]	[B]	[C]	[D]	[E]=1000*[A]/[D]	[F]=1000*[B]/[D]	[G]=1000*[C]/[D]	
1999	355	362						NA
2000	386	379	396	2,631	146.712	143.926	150.513	NA
2001	348	361	367	2,632	132.219	136.991	139.438	139.389
2002	382	380	387	2,841	134.460	133.861	136.220	141.009
2003	394	387	380	2,842	138.635	136.340	133.709	137.048
2004	384	377	384	2,914	131.778	129.294	131.778	132.534
2005	385	389	397	3,114	123.635	125.055	127.489	129.503
2000-2005	**-0.05%**	**0.56%**	**0.05%**	**3.37%**	**-3.42%**	**-2.81%**	**-3.32%**	**-1.84%**

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

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

Enbridge is thus a little more negative than that for Union. Results were very similar using GD costing.

3.5 Input Price Research

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

3.5.1 Input Price Subindexes and Costs

Applicable total cost was divided into the same input categories used in the development of the input quantity index. The cost share weights were modestly different from those in the input *quantity* indexes used to calculate TFP because all taxes were removed from the cost of capital. We thereby assume, effectively, that the price corresponding to taxes rises at the average rate of all of the other prices.[32]

In the input price trend comparisons, the price subindex for labour was a Stats Canada index of Ontario construction worker *total* compensation. The price subindex for other O&M inputs was the Ontario GDPIPI for all goods and services. The capital price subindex was constructed from data on construction cost trends and the rate of return. The rate of return was a 65/35 average of Stats Canada indexes for long term corporate bond yields and the return on equity of Canada utilities.

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

3.5.2 Input Price Differentials

An IPD was noted in section 2 to be the difference between the input price trends of the economy and the industry. This is commonly computed by taking the difference between the trends over some sample period. It is not necessary to use the same sample

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

periods for the IPD and PD calculations. That is because a given sample period may not be suitable for capturing the long run trends of both input price and productivity indexes.

The determination of appropriate IPDs for an IR plan beginning in 2008 is complicated by recent developments in markets for gas utility inputs. The cost of gas utility construction rose at a brisk pace in 2004, 2005, and 2006 due, chiefly, to a run-up in world market prices of steel and polyvinyl chloride, the material used to make most plastic 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 considerably if the cost of funds does not rise when the construction cost index does. Because of this problem it is customary to smooth the growth in the real rate of return when calculating a GD service price index. PEG commonly does this by taking a three year moving average of the real rate of return when it calculates the service price.

Details of the calculation of the capital service price index using GD costing are reported in Table 12 and Figures 2 & 3. It can be seen that following five years of sluggish growth, the capital stock deflator that we used to measure the construction cost trend grew by over 3% annually in each of 2004 and 2005. 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 to a level reached on only one occasion in the last fifteen years. The smoothed rate of return also declined substantially.

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.

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 almost 10% in 2004. The sensitivity of the summary input price indexes to

Table 12

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

Year	Rate of Return						Construction Cost		Real Rate of Return				Depreciation	Capital Service Price Indexes			
	Corporate Long Term Bond Yield		Return on Equity[3]		Weighted Average Cost of Capital				Unsmoothed		Smoothed		Rate[6]	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]=C-E	(%)	[G]=3 Year Moving Average of [F]	(%)	[H]	$[I]=F*D_{(t-1)}+H*D_t$	(%)	$[J]=D_{(t-1)}*G+H*D_t$	(%)
1988	10.9%		12.7%	6.4%	9.4%		0.821		9.4%				3.7%	0.1046			
1989	10.8%	-1.1	11.5%	5.5%	8.9%	-4.6	0.846	3.0%	5.9%	-45.8			3.7%	0.0800	-26.8		
1990	11.9%	9.7	7.6%	4.2%	9.2%	2.9	0.852	0.8%	8.4%	35.3	7.9%		3.7%	0.1029	25.2	0.0985	
1991	10.8%	-9.7	3.9%	3.5%	8.3%	-10.9	0.870	2.0%	6.2%	-30.5	6.9%	-14.3	3.7%	0.0852	-18.9	0.0907	-8.2
1992	9.9%	-8.8	1.7%	6.0%	8.5%	3.1	0.886	1.9%	6.7%	6.9	7.1%	3.5	3.7%	0.0907	6.3	0.0946	4.2
1993	8.8%	-11.2	3.8%	6.2%	7.9%	-7.0	0.904	2.0%	6.0%	-11.1	6.3%	-12.4	3.7%	0.0862	-5.1	0.0891	-6.0
1994	9.4%	6.5	6.7%	5.9%	8.2%	3.3	0.937	3.7%	4.5%	-28.9	5.7%	-9.8	3.7%	0.0751	-13.9	0.0862	-3.3
1995	9.0%	-4.6	9.8%	5.5%	7.8%	-5.1	0.945	0.8%	7.0%	44.4	5.8%	1.8	3.7%	0.1003	28.9	0.0893	3.6
1996	8.1%	-10.6	10.3%	6.2%	7.4%	-4.7	0.976	3.2%	4.3%	-49.2	5.2%	-10.3	3.7%	0.0764	-27.2	0.0856	-4.3
1997	7.0%	-15.4	10.9%	5.4%	6.4%	-14.7	1.000	2.5%	3.9%	-8.1	5.0%	-3.5	3.7%	0.0753	-1.4	0.0863	0.9
1998	6.2%	-11.1	8.8%	5.0%	5.8%	-10.2	1.033	3.3%	2.5%	-46.6	3.5%	-35.3	3.7%	0.0629	-18.0	0.0738	-15.7
1999	6.6%	6.5	9.9%	8.9%	7.4%	24.6	1.050	1.6%	5.8%	86.4	4.1%	13.9	3.7%	0.0992	45.5	0.0810	9.4
2000	7.1%	7.1	10.9%	7.3%	7.2%	-3.2	1.072	2.1%	5.1%	-13.2	4.5%	9.3	3.7%	0.0934	-6.0	0.0867	6.7
2001	7.1%	-0.5	7.4%	10.2%	8.2%	12.9	1.074	0.2%	8.0%	44.6	6.3%	34.5	3.7%	0.1254	29.5	0.1075	21.5
2002	7.0%	-1.6	5.7%	6.4%	6.8%	-18.8	1.088	1.3%	5.5%	-37.1	6.2%	-1.7	3.7%	0.0995	-23.2	0.1069	-0.5
2003	6.5%	-7.1	9.6%	7.4%	6.8%	0.5	1.089	0.1%	6.7%	19.3	6.7%	8.1	3.7%	0.1131	12.8	0.1136	6.0
2004	6.1%	-7.0	11.4%	8.4%	6.9%	0.7	1.131	3.9%	3.0%	-80.2	5.1%	-28.4	3.7%	0.0746	-41.6	0.0971	-15.6
2005	5.4%	-12.3	11.4%	7.4%	6.1%	-12.2	1.167	3.2%	2.9%	-2.5	4.2%	-18.7	3.7%	0.0764	2.3	0.0908	-6.7
Average Annual Growth Rate (%) 1999-2005		**-3.56**	**2.37**	**-3.05**		**-3.35**		**1.76**		**-11.52**		**0.52**	**0.00**		**-4.37**		**1.90**

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

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

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

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

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

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

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

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

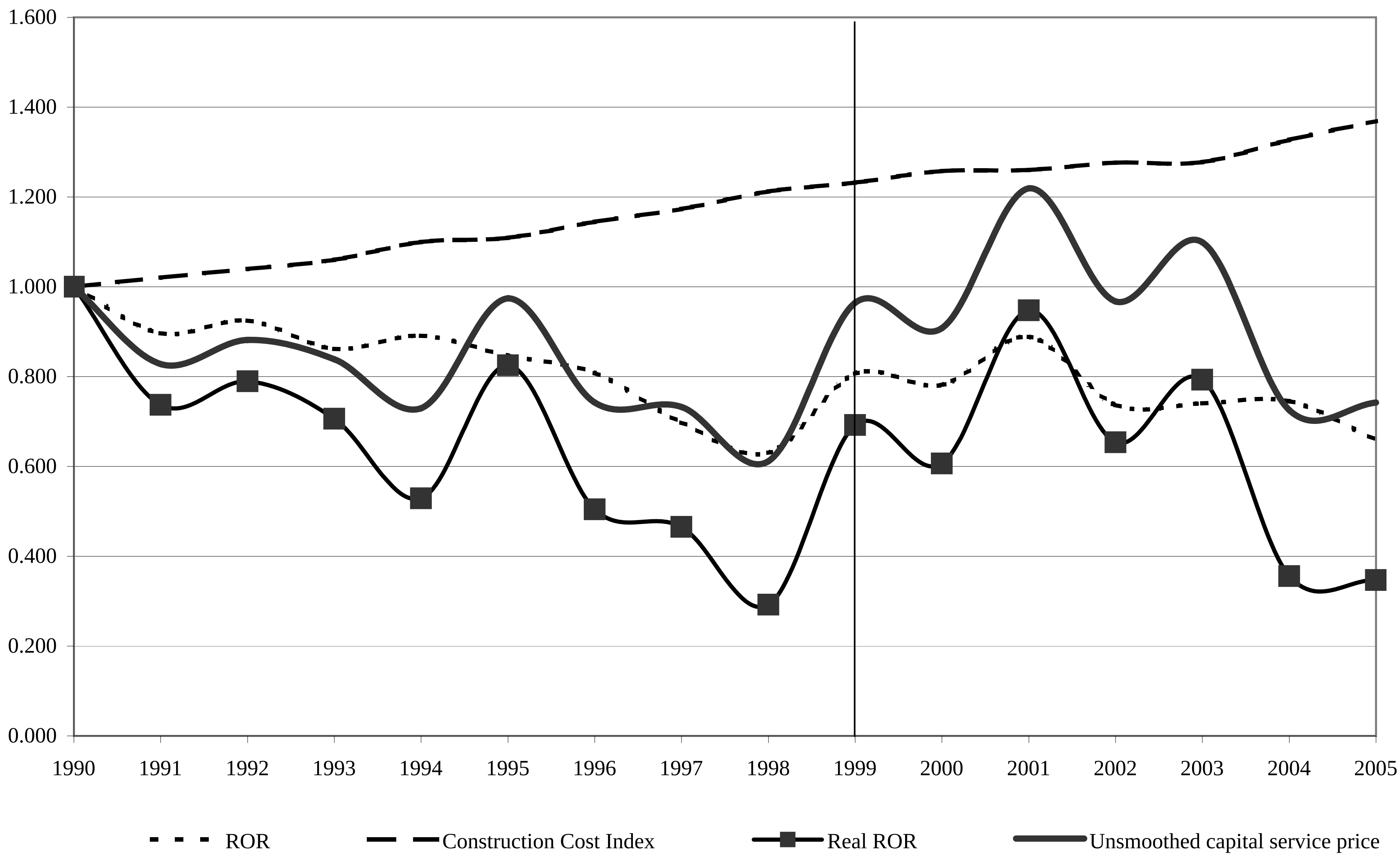

FIGURE 3: COMPARISONS OF ALTERNATIVE CAPITAL SERVICE PRICE INDEXES

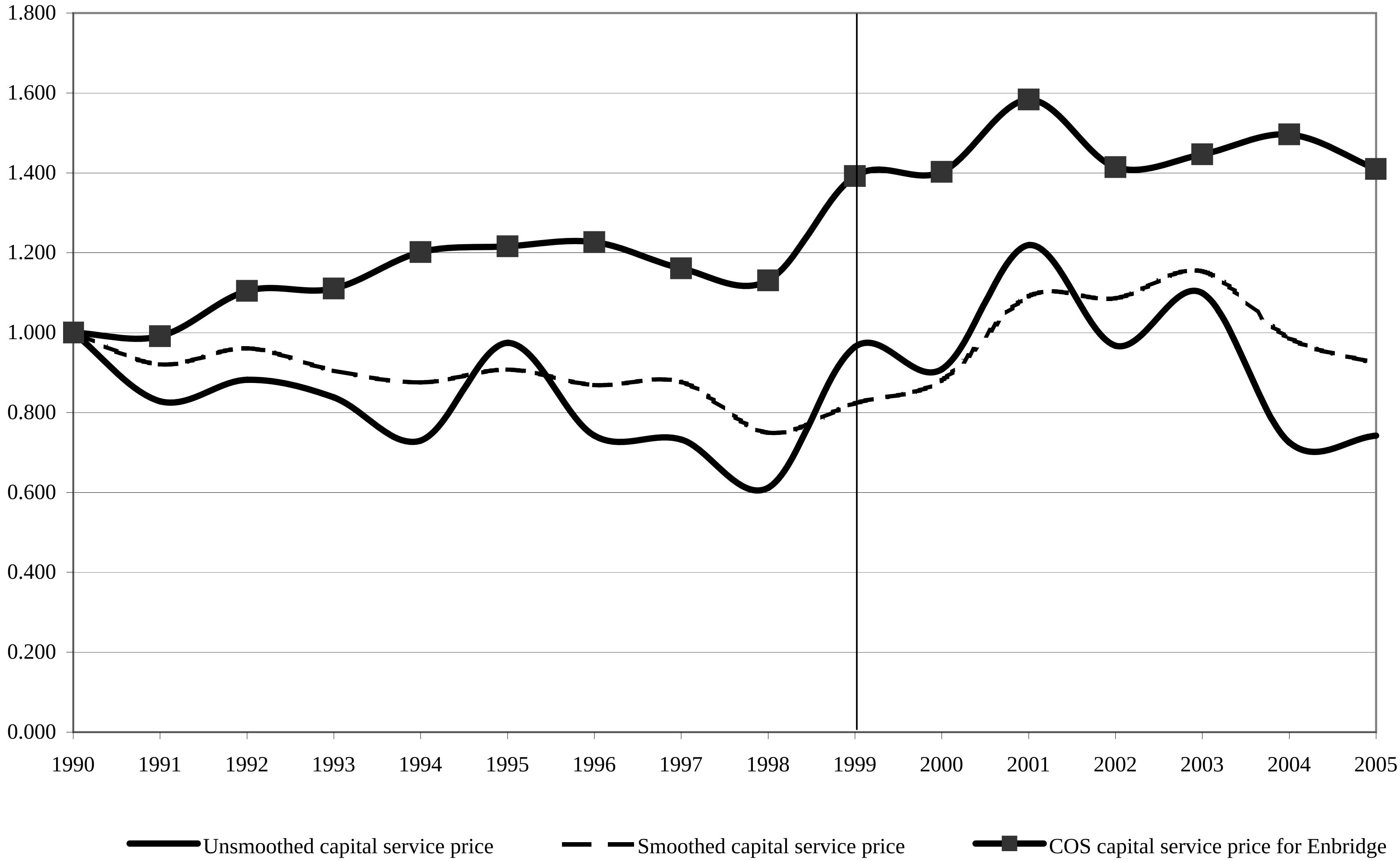

Table 13a

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			Summary Index Unsmoothed		Summary Index Smoothed	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Level	Growth Rate (%)	Level	Growth Rate (%)
1988	0.10		66.7				80.1		10.7	100.2		0.0	82.2		22.6	1.00			
1989	0.08	-26.8	66.7			66.7	85.1	6.1	10.7	95.6	-4.7	0.0	86.4	5.0	22.6	0.85	-16.1		
1990	0.10	25.2	66.7	0.10		66.7	90.3	5.9	10.7	96.5	0.9	0.0	89.2	3.2	22.6	1.02	18.1	1.00	
1991	0.09	-18.9	66.7	0.09	-8.2	66.7	96.5	6.6	10.7	98.2	1.7	0.0	93.0	4.2	22.6	0.92	-10.9	0.96	-3.8
1992	0.09	6.3	66.7	0.09	4.2	66.7	100	3.6	10.7	98.4	0.2	0.0	93.2	0.2	22.6	0.96	4.6	0.99	3.2
1993	0.09	-5.1	66.7	0.09	-6.0	66.7	102.6	2.6	10.7	104.5	6.0	0.0	94.6	1.5	22.6	0.93	-2.8	0.96	-3.4
1994	0.08	-13.9	66.7	0.09	-3.3	66.7	105.7	3.0	10.7	114.8	9.4	0.0	94.7	0.1	22.6	0.85	-8.9	0.94	-1.9
1995	0.10	28.9	66.7	0.09	3.6	66.7	108.3	2.4	10.7	94.2	-19.8	0.0	96.8	2.2	22.6	1.04	20.1	0.97	3.2
1996	0.08	-27.2	66.7	0.09	-4.3	66.7	109.5	1.1	10.7	94.6	0.4	0.0	98.4	1.6	22.6	0.87	-17.6	0.95	-2.4
1997	0.08	-1.4	66.7	0.09	0.9	66.7	111.5	1.8	10.7	100.0	5.6	0.0	100.0	1.6	22.6	0.87	-0.4	0.96	1.1
1998	0.06	-18.0	66.7	0.07	-15.7	66.7	113.6	1.9	10.7	111.1	10.5	0.0	100.3	0.3	22.6	0.77	-11.7	0.87	-10.2
1999	0.10	45.5	66.7	0.08	9.4	66.7	115.4	1.6	10.7	125.7	12.3	0.0	101.0	0.7	22.6	1.05	30.7	0.93	6.6
2000	0.09	-6.0	66.7	0.09	6.7	66.7	117.9	2.1	10.7	167.6	28.8	0.0	102.7	1.7	22.6	1.02	-3.4	0.98	5.1
2001	0.13	29.5	68.7	0.11	21.5	68.7	120.8	2.4	9.5	250.1	40.0	0.0	103.9	1.2	21.8	1.25	20.4	1.13	15.1
2002	0.10	-23.2	70.0	0.11	-0.5	70.0	124.6	3.1	8.5	214.8	-15.2	0.0	106.1	2.1	21.5	1.07	-15.3	1.14	0.4
2003	0.11	12.8	67.9	0.11	6.0	67.9	127.8	2.5	8.6	225.0	4.6	0.0	107.8	1.6	23.5	1.18	9.4	1.19	4.7
2004	0.07	-41.6	63.9	0.10	-15.6	63.9	131.5	2.9	10.1	226.8	0.8	0.0	110.1	2.1	26.0	0.90	-26.6	1.09	-9.5
2005	0.08	2.3	61.9	0.09	-6.7	61.9	135.6	3.1	11.3	239.6	5.5	0.0	111.2	1.0	26.9	0.92	2.0	1.05	-3.6
Average Annual Growth Rate (%) 1999-2005		**-4.37**			**1.90**			**2.69**			**10.75**			**1.60**			**-2.24**		**2.02**

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

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

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

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

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

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			Summary Index Unsmoothed		Summary Index Smoothed	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Level	Growth Rate (%)	Level	Growth Rate (%)
1988	0.10		62.4				80.1		21.0	100.2		1.4	82.2		15.2	1.00			
1989	0.08	-26.8	62.4				85.1	6.1	21.0	95.6	-4.7	1.4	86.4	5.0	15.2	0.86	-14.8		
1990	0.10	25.2	62.4	0.10		62.4	90.3	5.9	21.0	96.5	0.9	1.4	89.2	3.2	15.2	1.03	17.5	1.00	
1991	0.09	-18.9	62.4	0.09	-8.2	62.4	96.5	6.6	21.0	98.2	1.7	1.4	93.0	4.2	15.2	0.93	-9.7	0.97	-3.1
1992	0.09	6.3	62.4	0.09	4.2	62.4	100	3.6	21.0	98.4	0.2	1.4	93.2	0.2	15.2	0.98	4.7	1.00	3.4
1993	0.09	-5.1	62.4	0.09	-6.0	62.4	102.6	2.6	21.0	104.5	6.0	1.4	94.6	1.5	15.2	0.95	-2.3	0.97	-2.9
1994	0.08	-13.9	62.4	0.09	-3.3	62.4	105.7	3.0	21.0	114.8	9.4	1.4	94.7	0.1	15.2	0.88	-7.9	0.96	-1.3
1995	0.10	28.9	62.4	0.09	3.6	62.4	108.3	2.4	21.0	94.2	-19.8	1.4	96.8	2.2	15.2	1.06	18.6	0.99	2.8
1996	0.08	-27.2	62.4	0.09	-4.3	62.4	109.5	1.1	21.0	94.6	0.4	1.4	98.4	1.6	15.2	0.90	-16.5	0.97	-2.2
1997	0.08	-1.4	62.4	0.09	0.9	62.4	111.5	1.8	21.0	100.0	5.6	1.4	100.0	1.6	15.2	0.90	-0.2	0.98	1.2
1998	0.06	-18.0	62.4	0.07	-15.7	62.4	113.6	1.9	21.0	111.1	10.5	1.4	100.3	0.3	15.2	0.81	-10.6	0.89	-9.2
1999	0.10	45.5	62.4	0.08	9.4	62.4	115.4	1.6	21.0	125.7	12.3	1.4	101.0	0.7	15.2	1.08	29.0	0.95	6.5
2000	0.09	-6.0	62.9	0.09	6.7	62.9	117.9	2.1	20.3	167.6	28.8	2.7	102.7	1.7	14.1	1.05	-2.5	1.01	5.5
2001	0.13	29.5	65.6	0.11	21.5	65.6	120.8	2.4	18.2	250.1	40.0	2.9	103.9	1.2	13.4	1.30	20.7	1.18	15.5
2002	0.10	-23.2	64.1	0.11	-0.5	64.1	124.6	3.1	18.0	214.8	-15.2	2.5	106.1	2.1	15.4	1.12	-14.6	1.18	0.1
2003	0.11	12.8	64.5	0.11	6.0	64.5	127.8	2.5	17.6	225.0	4.6	4.1	107.8	1.6	13.8	1.23	9.1	1.24	4.7
2004	0.07	-41.6	60.3	0.10	-15.6	60.3	131.5	2.9	19.6	226.8	0.8	4.3	110.1	2.1	15.7	0.96	-25.1	1.13	-8.9
2005	0.08	2.3	58.2	0.09	-6.7	58.2	135.6	3.1	21.7	239.6	5.5	4.9	111.2	1.0	15.3	0.98	2.4	1.10	-2.9
Average Annual Growth Rate (%) 1999-2005		**-4.37**			**1.90**			**2.69**			**10.75**			**1.60**			**-1.67**		**2.34**

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

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

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

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

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

the fluctuations in the capital service components reflects in part the large weighting assigned to capital in index construction.

Using GD capital costing, we sought a period ending in 2005 in which the start year had a similar real rate of return on the premise that a notable change in the real rate of return is not likely during the IR plan. The 1999-2005 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 the data on the costs of the Ontario utilities 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 GDPIPI 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 estimate the trend in the economy's input prices.

Results for the 1999-2005 period are calculated and highlighted in Table 14 for reader convenience. We found that the appropriate input price differentials for Enbridge and Union using GD capital costing were 0.86% and 0.54% respectively. The smaller difference for Union reflects chiefly its greater reliance on natural gas, which grew rapidly in price over the sample period.

As for the COS capital service price indexes, we chose 1998 as the corresponding start date since (from Table 12) the weighted average cost of funds in that year is similar to that in 2005. This approach is based on the premise that the weighted average cost of funds won't change over the sample period.

Input price trends using the COS approach to capital costing are reported in Tables 15a and 15b. These employ the same price subindexes for labour, gas, and M&S that are used with the GD costing. The capital service prices reflect the COS treatment and

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	-16.1	NA	-14.8	NA	19.1	NA	17.8	NA
1990	88.4	3.7	97.7	-2.2	1.5	18.1	NA	17.5	NA	-16.7	NA	-16.0	NA
1991	91.4	3.3	95.0	-2.8	0.5	-10.9	-3.8	-9.7	-3.1	11.5	4.4	10.3	3.6
1992	93.0	1.7	95.9	0.9	2.7	4.6	3.2	4.7	3.4	-1.9	-0.6	-2.0	-0.7
1993	94.9	2.0	96.3	0.4	2.4	-2.8	-3.4	-2.3	-2.9	5.2	5.8	4.7	5.3
1994	96.3	1.5	99.0	2.8	4.2	-8.9	-1.9	-7.9	-1.3	13.1	6.1	12.1	5.5
1995	97.4	1.1	99.5	0.5	1.6	20.1	3.2	18.6	2.8	-18.4	-1.5	-17.0	-1.2
1996	98.5	1.1	98.7	-0.8	0.3	-17.6	-2.4	-16.5	-2.2	18.0	2.7	16.8	2.5
1997	100.0	1.5	100.0	1.3	2.8	-0.4	1.1	-0.2	1.2	3.2	1.7	3.0	1.6
1998	101.3	1.3	101.1	1.1	2.4	-11.7	-10.2	-10.6	-9.2	14.1	12.6	13.0	11.6
1999	102.6	1.3	103.5	2.3	3.6	30.7	6.6	29.0	6.5	-27.1	-3.0	-25.4	-2.8
2000	105.0	2.3	106.1	2.5	4.8	-3.4	5.1	-2.5	5.5	8.2	-0.3	7.3	-0.7
2001	106.8	1.7	106.7	0.6	2.3	20.4	15.1	20.7	15.5	-18.2	-12.8	-18.4	-13.3
2002	109.3	2.3	108.9	2.0	4.4	-15.3	0.4	-14.6	0.1	19.7	4.0	18.9	4.2
2003	110.8	1.4	109.0	0.1	1.5	9.4	4.7	9.1	4.7	-7.9	-3.3	-7.6	-3.2
2004	112.7	1.7	109.5	0.5	2.2	-26.6	-9.5	-25.1	-8.9	28.8	11.7	27.2	11.0
2005	114.7	1.8	*110.0* [3]	0.5	2.3	2.0	-3.6	2.4	-2.9	0.2	5.9	-0.1	5.2
Average Annual Growth Rate (%) 1999-2005		**1.86**		**1.02**	**2.88**	**-2.24**	**2.02**	**-1.67**	**2.34**	**5.13**	**0.86**	**4.55**	**0.54**

[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 were imputed using the 2004 MFP Growth Rate due to a lack of data.

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

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

Table 15a

Input Price Index with COS Capital Cost: Enbridge Gas Distribution

	Capital (COSR Method)			Labour			Natural Gas			Materials and Services			Summary Index	
Year	Index[0]	Growth Rate (%)	Weight[1] (%)	Index[2]	Growth Rate (%)	Weight[1] (%)	Index[3]	Growth Rate (%)	Weight[1] (%)	Index[4]	Growth Rate (%)	Weight[1] (%)	Index	Growth Rate (%)
1990	0.0569		65.3	90.3		11.1	96.5		0.0	89.2		23.6	1.000	
1991	0.0564	-0.9	65.3	96.5	6.6	11.1	98.2	1.7	0.0	93.0	4.2	23.6	1.011	1.1
1992	0.0629	10.9	65.3	100	3.6	11.1	98.4	0.2	0.0	93.2	0.2	23.6	1.090	7.5
1993	0.0632	0.5	65.3	102.6	2.6	11.1	104.5	6.0	0.0	94.6	1.5	23.6	1.101	1.0
1994	0.0684	7.9	65.3	105.7	3.0	11.1	114.8	9.4	0.0	94.7	0.1	23.6	1.164	5.5
1995	0.0692	1.2	65.3	108.3	2.4	11.1	94.2	-19.8	0.0	96.8	2.2	23.6	1.182	1.6
1996	0.0698	0.9	65.3	109.5	1.1	11.1	94.6	0.4	0.0	98.4	1.6	23.6	1.195	1.1
1997	0.0661	-5.5	65.3	111.5	1.8	11.1	100.0	5.6	0.0	100.0	1.6	23.6	1.159	-3.0
1998	0.0643	-2.6	65.3	113.6	1.9	11.1	111.1	10.5	0.0	100.3	0.3	23.6	1.142	-1.4
1999	0.0792	20.8	65.3	115.4	1.6	11.1	125.7	12.3	0.0	101.0	0.7	23.6	1.313	13.9
2000	0.0798	0.7	65.3	117.9	2.1	11.1	167.6	28.8	0.0	102.7	1.7	23.6	1.328	1.1
2001	0.0901	12.1	64.4	120.8	2.4	10.8	250.1	40.0	0.0	103.9	1.2	24.8	1.445	8.4
2002	0.0805	-11.3	65.6	124.6	3.1	9.7	214.8	-15.2	0.0	106.1	2.1	24.7	1.354	-6.5
2003	0.0823	2.2	61.8	127.8	2.5	10.3	225.0	4.6	0.0	107.8	1.6	28.0	1.382	2.1
2004	0.0851	3.4	60.7	131.5	2.9	11.0	226.8	0.8	0.0	110.1	2.1	28.2	1.424	3.0
2005	0.0802	-6.0	60.3	135.6	3.1	11.8	239.6	5.5	0.0	111.2	1.0	28.0	1.382	-3.0
Average Annual Growth Rates (%)														
1998-2005		**3.15**			**2.53**			**10.98**			**1.47**			**2.72**

[0] PEG calculation using Enbridge plant data.

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

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

[3] Source: Statistics Canada, 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[0]	Capital Growth Rate (%)	Capital Weight[1] (%)	Labour Index[2]	Labour Growth Rate (%)	Labour Weight[1] (%)	Natural Gas Index[3]	Natural Gas Growth Rate (%)	Natural Gas Weight[1] (%)	Materials and Services Index[4]	Materials and Services Growth Rate (%)	Materials and Services Weight[1] (%)	Summary Index Index	Summary Index Growth Rate (%)
1990	0.0604		54.0	90.3		31.7	96.5		1.7	89.2		12.6	1.000	
1991	0.0604	0.0	54.0	96.5	6.6	31.7	98.2	1.7	1.7	93.0	4.2	12.6	1.027	2.64
1992	0.0654	8.0	54.0	100	3.6	31.7	98.4	0.2	1.7	93.2	0.2	12.6	1.085	5.49
1993	0.0654	-0.1	54.0	102.6	2.6	31.7	104.5	6.0	1.7	94.6	1.5	12.6	1.096	1.03
1994	0.0704	7.5	54.0	105.7	3.0	31.7	114.8	9.4	1.7	94.7	0.1	12.6	1.154	5.16
1995	0.0719	2.1	54.0	108.3	2.4	31.7	94.2	-19.8	1.7	96.8	2.2	12.6	1.175	1.82
1996	0.0717	-0.3	54.0	109.5	1.1	31.7	94.6	0.4	1.7	98.4	1.6	12.6	1.180	0.43
1997	0.0668	-7.1	54.0	111.5	1.8	31.7	100.0	5.6	1.7	100.0	1.6	12.6	1.146	-2.94
1998	0.0644	-3.6	54.4	113.6	1.9	29.7	111.1	10.5	0.9	100.3	0.3	14.9	1.132	-1.22
1999	0.0786	19.9	58.8	115.4	1.6	23.0	125.7	12.3	1.5	101.0	0.7	16.6	1.276	11.93
2000	0.0791	0.7	60.0	117.9	2.1	21.9	167.6	28.8	2.9	102.7	1.7	15.2	1.298	1.78
2001	0.0892	12.0	60.0	120.8	2.4	21.1	250.1	40.0	3.3	103.9	1.2	15.5	1.423	9.15
2002	0.0799	-11.1	61.5	124.6	3.1	19.3	214.8	-15.2	2.7	106.1	2.1	16.5	1.337	-6.23
2003	0.0815	2.0	57.3	127.8	2.5	21.2	225.0	4.6	4.9	107.8	1.6	16.6	1.366	2.16
2004	0.0841	3.1	55.5	131.5	2.9	22.0	226.8	0.8	4.8	110.1	2.1	17.6	1.405	2.79
2005	0.0792	-6.1	54.7	135.6	3.1	23.5	239.6	5.5	5.3	111.2	1.0	16.5	1.374	-2.21
Average Annual Growth Rates (%)														
1998-2005		**2.94**			**2.53**			**10.98**			**1.47**			**2.77**

[0] PEG calculation using Union plant data.

[1] Weights based on research for Union Gas

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

[3] Source: Statistics Canada, Raw Materials Price Index for Natural Gas.

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

differ between the two companies due to differences in their historical investment patterns. These indexes are much more stable than their GD counterparts and required no smoothing.

Input price differentials using COS costing are reported in Table 16. Results for the 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 0.27% and 0.22%, respectively. Results using both methods substantiate the notion that the input price trends of Ontario gas utilities are somewhat slower than the trend in the GDPIPI FDD. We find the numbers using COS capital costing to be more plausible.

The greater stability of the COS input price index is evidently a major advantage in the calculation of IPDs. For example, the choice of an appropriate sample period for IPD calculations is less controversial. The COS method thus provides a solid basis for IPD calculations in addition to providing a useful point of comparison for IPDs calculated using GD costing. The GD approach is more familiar to Ontario stakeholders and better established. On balance, we nonetheless recommend the use of the COS approach to capital costing in the design of rate adjustment indexes for Enbridge and Union.

3.6 Stretch Factor

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

A second substantive basis for choosing stretch factors is our incentive power research for Board staff. Our incentive power model calculates the typical performance that can be expected of utilities under alternative stylized regulatory systems.[33] By comparing the performance predicted under an approximation to the regulatory system under which sampled utilities operated to that predicted under an approximation of the envisioned IR

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

Table 16

Input Price Differentials with COS Capital Cost

	Canadian Economy						Ontario Gas Industry				Input Price Differential	
	GDP-IPI[1]		MFP[2]		Implied IPI		Enbridge[4]		Union[5]			
	Level	Growth Rate [A] (%)	Level	Growth Rate [B] (%)	Index	Growth Rate [C]=A+B (%)	Index	Growth Rate [D] (%)	Index	Growth Rate [E] (%)	Enbridge [C]-[D] (%)	Union [C]-[E] (%)
1990	88.4		97.7		1.00		1.00		1.00			
1991	91.4	3.3	95.0	-2.8	1.01	0.5	1.01	1.1	1.03	2.6	-0.6	-2.1
1992	93.0	1.7	95.9	0.9	1.03	2.7	1.09	7.5	1.08	5.5	-4.9	-2.8
1993	94.9	2.0	96.3	0.4	1.06	2.4	1.10	1.0	1.10	1.0	1.4	1.4
1994	96.3	1.5	99.0	2.8	1.10	4.2	1.16	5.5	1.15	5.2	-1.3	-0.9
1995	97.4	1.1	99.5	0.5	1.12	1.6	1.18	1.6	1.18	1.8	0.1	-0.2
1996	98.5	1.1	98.7	-0.8	1.13	0.3	1.19	1.1	1.18	0.4	-0.8	-0.1
1997	100.0	1.5	100.0	1.3	1.16	2.8	1.16	-3.0	1.15	-2.9	5.9	5.8
1998	101.3	1.3	101.1	1.1	1.19	2.4	1.14	-1.4	1.13	-1.2	3.8	3.6
1999	102.6	1.3	103.5	2.3	1.23	3.6	1.31	13.9	1.28	11.9	-10.3	-8.3
2000	105.0	2.3	106.1	2.5	1.29	4.8	1.33	1.1	1.30	1.8	3.7	3.0
2001	106.8	1.7	106.7	0.6	1.32	2.3	1.44	8.4	1.42	9.1	-6.1	-6.9
2002	109.3	2.3	108.9	2.0	1.38	4.4	1.35	-6.5	1.34	-6.2	10.8	10.6
2003	110.8	1.4	109.0	0.1	1.40	1.5	1.38	2.1	1.37	2.2	-0.6	-0.7
2004	112.7	1.7	109.5	0.5	1.43	2.2	1.42	3.0	1.40	2.8	-0.8	-0.6
2005	114.7	1.76	*110.0* [3]	*0.5*	1.46	2.3	1.38	-3.0	1.37	-2.2	5.2	4.5
Average Annual Growth Rates (%)												
1998-2005		**1.77**		**1.21**		**2.99**		**2.72**		**2.77**	**0.27**	**0.22**

[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 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.

plan, we can estimate the expected performance improvement resulting from the change in regulation. The last step in the analysis is to share the expected improvement between the company and its customers.

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

3.7 Summary PCI Results

For reader convenience, we gather in the table below the results of our research to calculate X factors for the summary PCIs of Enbridge and Union. The table provides, in italics, a notion of the growth in these PCIs during the IR plan. This projection requires an assumption regarding GDPIPI growth, and we use for this purpose the recent historical trend. The growth in the *actual* PCI would reflect the growth in the actual GDPIPI for final domestic demand during the IR plan period. The table presents, finally, indexes computed by PEG of the trend in each company's rates during the 2000-2005 period.

Price Cap Index Details

	GD Capital Cost		COS Capital Cost	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.91	1.46	2.10	1.73
$TFP^{Economy}$ [B]	1.02	1.02	1.21	1.21
PD [C=A-B]	**0.89**	**0.44**	**0.89**	**0.52**
Input $Prices^{Economy}$ [D]	2.88	2.88	2.99	2.99
Input $Prices^{Industry}$ [E]	2.02	2.34	2.72	2.77
IPD [F=D-E]	**0.86**	**0.54**	**0.27**	**0.22**
$Output^{Revenue\text{-}Weighted}$ [G]	2.02	1.20	2.02	1.20
$Output^{Elasticity\text{-}Weighted}$ [H]	2.74	1.83	2.83	1.92
AU [I=G-H]	**-0.72**	**-0.63**	**-0.81**	**-0.72**
Stretch [J]	**0.50**	**0.50**	**0.50**	**0.50**
X [K=C+F+I+J]	**1.53**	**0.85**	**0.85**	**0.52**
GDPIPI FDD [*L*]	*1.86*	*1.86*	*1.86*	*1.86*
Notional PCI growth [*L-K*]	*0.33*	*1.01*	*1.01*	*1.34*

It can be seen that, for both companies, the growth of the PCIs based on the recommended COS approach to capital costing would be materially slower than the growth in the GDPIPI. Ontario gas consumers would, in other words, experience growth in rates for gas utility services that are below the general inflation in the prices of final goods and services in Canada. The higher X for Enbridge is chiefly due to its greater opportunities to realize scale economies. Note, finally, that the notional PCI trend for each company is similar to the trend in their actual rates during the 2000-2005 period.

3.8 Price Caps for Service Groups

We propose that any PCI designed for a specific service group have a GDPIPI-X growth rate formula in which the X factor is the sum of the X factor for the *summary* PCI and a special adjustment factor ("ADJ") that is specific to the service group and effectively customizes the X factor for the group. We recommend that there be separate PCIs for each rate class that contains residential customers. All other service classes of Enbridge and Union would be subject to common PCIs.

Original theoretical and empirical research was undertaken to provide a rigorous foundation for the design of ADJ factors. The basic intuition is that the PCI for a specific service group should reflect the manner in which its impact on revenue and cost growth differs from the impact of *all* services. The impact of a service group on TFP growth depends on the pace and pattern of its output growth. X factors can therefore be customized by calculating how the output growth of the service group differs from that of the company overall. Output growth has an impact on cost as well as revenue. The ADJ is thus the sum of separate calculations of the revenue effect and the cost effect. Details of the theory are set forth in Section A.7.4 of the Appendix.

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

In table 17 we provide calculations of the ADJ factors for several service groups and a notion of the growth trend of the resultant PCIs. The cost effects are separately calculated using both GD and COS costing. Using both approaches to capital costing it can be seen that all three service classes that include service to residential customers have negative ADJ factors, as we would expect. These will lower the X factors and cause the PCIs to grow more rapidly than the summary PCI. Customers of these services will thus play a disproportionately large role in compensating utilities for the special financial challenges that service to the groups poses. The indicated ADJs for the non-residential services of Enbridge and Union (0.69% and 1.20%, respectively) are positive. This will

Table 17

Calculation of the ADJ Factors

Company Service	Share Volume Residential (2002)	Revenue Effect [A]	Geometric Decay Capital Costing Cost Effect [B]	 ADJ [A+B]	COS Capital Costing Cost Effect [C]	 ADJ [A+C]
Enbridge						
Rate 1 (Residential)	100%	0.64%	-1.04%	-0.40%	-1.12%	-0.48%
All Non-Residential Services	0%	-1.23%	1.92%	0.69%	1.92%	0.69%
Union						
Rate 01 (General Services North)	75%	-1.12%	0.51%	-0.61%	0.47%	-0.65%
Rate M2 (General Services South)	54%	0.31%	-0.92%	-0.61%	-0.96%	-0.65%
All Services Other than 01 and M2	0%	0.06%	1.14%	1.20%	1.20%	1.26%

raise their X factors and slow the pace of PCI growth. Customers of these services will thus enjoy rate escalation that is considerably slower than the escalation of rates of services involving residential customers.

We provide preliminary estimates of the pace of escalation in the group-specific PCIs that might result from our calculations using COS capital costing by taking the difference between the trends in the GDPIPI from 1999 to 2005 and the X factor for each group. The actual growth in the PCIs would, once again depend on the GDPIPI growth that occurs during the IR plan period. Results of this crude forecasting method are presented in the following table.

Service Group PCIs

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	1.86	0.85	-0.48	0.37	1.49
	Nonresidential	1.86	0.85	0.69	1.54	0.32
Union	Rate M2	1.86	0.52	-0.65	-0.13	1.99
	Rate 1	1.86	0.52	-0.65	-0.13	1.99
	Nonresidential	1.86	0.52	1.26	1.78	0.08

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

3.9 Revenue Cap Index Results

The general formula for calculating the X factor of a revenue cap index was detailed in Section 2.2.4. This formula includes the inflation measure and X factor terms found in PCI formulas but also includes an explicit measure of output growth.

Our research permits an implementation of this formula. Illustrative results appear in the table below. To help stakeholders gauge the likely outcome of an RCI, we also provide, in italics, a notion of how one might rise if the output and GDPIPI terms of the formula grow at their average annual growth rates over the 2000-2005 period.

Revenue Cap Index Details

	GD Capital Cost		COS Capital Cost	
	Enbridge	**Union**	**Enbridge**	**Union**
$TFP^{Industry}$ [A]	1.91	1.46	2.10	1.73
$TFP^{Economy}$ [B]	1.02	1.02	1.21	1.21
PD [C=A-B]	**0.89**	**0.44**	**0.89**	**0.52**
Input $Prices^{Economy}$ [D]	2.88	2.88	2.99	2.99
Input $Prices^{Industry}$ [E]	2.02	2.34	2.72	2.77
IPD [F=D-E]	**0.86**	**0.54**	**0.27**	**0.22**
Stretch [G]	**0.50**	**0.50**	**0.50**	**0.50**
X^{RCI} [H=C+F+I]	**2.25**	**1.48**	**1.66**	**1.24**
***$Output^{Elasticity\text{-}Weighted}$* [*I*]**	***2.74***	***1.83***	***2.83***	***1.92***
***GDPIPI* [*J*]**	***1.86***	***1.86***	***1.86***	***1.86***
***Indicated RCI Growth* [*J-H+I*]**	***2.35***	***2.21***	***3.03***	***2.54***

In this calculation, the output index is assumed to have the same form as the elasticity-weighted indexes used in our TFP calculations.[35] This approach has the advantage of being applicable to both Union, with its large transmission volumes, and Enbridge. The growth rate of the GDPIPI is set at the 1.86% average annual rate achieved from 1999 to 2005. It can be seen that, despite material differences in the operating conditions of the two companies, the allowed trends in revenue requirement growth are quite similar. That is because the rapid output growth that results in the higher productivity target for Enbridge and thereby raises its X also results in a more rapid output growth adjustment.

[35] Volume trends would have to be weathered normalized in an actual application, as they are in these computations.

Alternative and simpler measures of output, such as the number of customers served, can also be considered. If used, the TFP trend of the industry must be recalculated using the same output measure. If the number of customers is used as the output measure, the PD is apt to rise because the number of customers grew more rapidly than the delivery volume during the sample period. The actual growth in the RCI would depend on the GDPIPI growth during the years of the sample plan.

Appendix

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

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

Here in each year t,

$Output\ Quantities_t$ = Output quantity index

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

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

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

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

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

Here in each year t,

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

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

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

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

A.1.2 Weather Normalization of Volume Data

The residential and commercial volumes used in this study were adjusted for weather volatility. We adjusted all reported residential and commercial volumes of the U.S. utilities, as well as the volumes for Union Gas rates M2, 01, and 10 and Enbridge rates 1, 6, and 100.

Following comments by Enbridge, Union, and Keith Ritchie of Board staff, we have made changes to the weather normalization methodology that was used to prepare results for the first draft of this report. The weather adjustment still involved two separate steps. In the first, we used regional US delivery volume and HDD data to estimate the impact of HDD growth on delivery growth.[36] In particular, we regressed the growth rates of residential, residential and commercial, and commercial deliveries of individual sample distributors on the growth rate of HDDs, the growth rate of the number of customers, and additional terms involving the interaction between HDD growth and dummy variables pertaining to four US regions: Northeast, Mid-Latitude Midwest, Southeast and Southwest and Northwest. These variables permit the impact of HDD fluctuations on volumes to vary by region. We used this methodology to obtain coefficients that indicate the impact of HDD growth on the three

[36] All growth rates are calculated logarithmically.

different categories of deliveries. We used for this purpose the data from 36 US gas utilities, covering the years 1994-2004. The regression model used for all dependent variables was:

$$\begin{aligned}\ln(YV_t / YV_{t-1}) = \alpha_o + \alpha_N * \ln(N_t / N_{t-1}) + \alpha_{HDD} * \ln(HDD_t / HDD_{t-1}) &+ \alpha_{DUMNE*HDD} * DUMNE * \ln(HDD_t / HDD_{t-1}) \\ &+ \alpha_{DUMM*HDD} * DUMM * \ln(HDD_t / HDD_{t-1}) \\ &+ \alpha_{DUMSE*HDD} * DUMSE * \ln(HDD_t / HDD_{t-1}) \\ &+ \alpha_{DUMNW*HDD} * DUMNW * \ln(HDD_t / HDD_{t-1}) \\ &+ \varepsilon\end{aligned}$$

The term on the left hand side of this equation is the logarithmic growth of deliveries from year *t-1* to year *t*. The first term on the right hand side is a parameter for the constant term. The second term is the growth rate of HDDs. The third term specifies the impact of customer growth on delivery growth while the fourth to seventh terms capture regional differences in the impact of HDD growth on volume growth. The last term is the stochastic term of the regression.

Table 18 provides the parameter estimates from the regressions undertaken using the US data. While the signs of the coefficients indicate the direction of the effect of the growth of right hand side variables on volume growth, the magnitudes reflect the extent of these effects. For instance, the coefficient of the HDD growth from the regression of residential and commercial delivery growth indicates that, for a 1% growth in HDD, residential and commercial deliveries grow by 0.291%. We also note that the parameter estimates or coefficients of all regional adjustment variables are positive and significant at the 9% confidence level seven times out of twelve. For our purposes it is most important to observe that the positive and significant coefficients of the Northeastern US dummy variable indicate that growth in HDD affects growth in residential, residential and commercial, and commercial deliveries positively in this region.

In step two of the exercise, we weather normalize the residential and commercial delivery volumes by removing the effect of actual HDDs and using instead the effect of the average HDDs over the six year sample period. The formula for Enbridge, Union, and the U.S. utilities in the Northeast region for this purpose is:

$$\ln(YV_t)^{normalized} = \ln(YV_t) + (\hat{\alpha}_{HDD} + \hat{\alpha}_{DUMNE*HDD}) * \ln\left(HDD^{average} / HDD_t\right)$$

where $\hat{\alpha}_{HDD}$ is the HDD parameter estimate and $\hat{\alpha}_{DUMNE*HDD}$ is the estimate of the

Table 18

Econometric Models For Weather Normalization

VARIABLE KEY

yvrc = Logarithmic Growth Rate of Residential and Commercial Throughput
yvres = Logarithmic Growth Rate of Residential Throughput
yvcom = Logarithmic Growth Rate of Commercial Throughput
HDD = Logarithmic Growth Rate of Heating Degree
N = Logarithmic Growth Rate of the Number of Customers
DUMNE x HDD = Regional Dummy: Northeast US x Logarithmic Growth Rate of Heating Degree Days
DUMM x HDD = Regional Dummy: Middle Latitude Eastern US x Logarithmic Growth Rate of Heating Degree Days
DUMSE x HDD = Regional Dummy: Southeast US x Logarithmic Growth Rate of Heating Degree Days
DUMNW x HDD = Regional Dummy: Northwest US x Logarithmic Growth Rate of Heating Degree Days

	Dependent Variable					
Explanatory Variables	**ycrc**		**yvres**		**yvcom**	
	Parameter Estimate[1]	**T-Statistic**	**Parameter Estimate**	**T-Statistic**	**Parameter Estimate**	**T-Statistic**
constant	0.002	0.399	-0.004	-0.745	0.011	1.825
HDD	0.239	3.671	0.298	4.763	0.139	1.396
N	0.358	1.698	0.635	3.135		
DUMNE x HDD	0.291	3.415	0.264	3.229	0.330	2.520
DUMM x HDD	0.215	2.466	0.303	3.620	0.114	0.853
DUMSE x HDD	-0.059	-0.718	-0.093	-1.191	-0.004	-0.032
DUMNW x HDD	0.369	2.077	0.394	2.311	0.358	1.311
sample period	1994-2005		1994-2005		1994-2005	
Adjusted R-squared	0.350		0.454		0.106	
Number of Observations	360		360		360	

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

Northeast regional HDD adjustment parameter.[38]

Union's deliveries in rate classes 01 and M2 were normalized using the coefficients from the residential and commercial deliveries regression while those in rate class 10 were normalized using the coefficients from the commercial deliveries regression. Enbridge's rate class 1 deliveries were normalized using the coefficients from the residential deliveries regression while those from rates 6 and 100 were normalized using the coefficients 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

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 for each company in each year t,

$Input\ Prices_t$ = Input price index

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

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

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

[38] Analogous formulas are used for US utilities in other regions.

A.2.2 Output Price Indexes

The output price indexes that we used in Section 3.7 to measure the overall rate trends of Enbridge and Union are calculated using the following general formula.

$$\ln\left(Rates_t / Rates_{t-1} \right) = \sum_i SR_{i,2005} \cdot \ln\left(P_{i,t} / P_{i,t-1} \right). \qquad [A4]$$

Here in each year t,

$Rates_t$ = Summary output price index

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

$SR_{i,t}$ = Share of rate element i in total base rate revenue in 2005

It can be seen that the logarithmic growth rate of the index is a weighted average of the logarithmic growth rates of the individual rate elements. The weights are the share of each rate element in the company's total base rate revenue.

A.3 Input Quantity Indexes

A.3.1 Index Form

The summary input quantity index for each company was of Törnqvist form.[39] This means that its annual growth rate was determined by the following general formula:

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

Here for each company in each year t,

$Input\ Quantities_t$ = Input quantity index

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

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

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

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

A.3.2 Input Quantity Subindexes

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

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

A.4 Capital Cost

The service price approach to the measurement of capital cost has a solid basis in economic theory and is widely used in scholarly empirical work.[40] 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 service price methods.

A.4.1 Geometric Decay

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

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

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

In this study there is only one category of plant. Our data reflect the cost of facilities for local delivery, transmission, storage, and metering as well as general plant. In constructing

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

capital quantity indexes we took 1983, 1985 and 1989 as the benchmark or starting years for the U.S. utilities, Union, and Enbridge respectively. These are the earliest years for which the requisite data are available.

Our calculations of the capital cost and quantity in the benchmark year are based on the net value of plant. The capital quantity index in the base year is the inflation adjusted value of net plant in that year. We calculated this by dividing the net plant (book) value by an average of the values of a construction cost index for a period ending in the benchmark year. The construction cost index (WKA_t) used in the U.S. calculations was the regional Handy-Whitman index of gas utility construction costs for the relevant region.[41] The construction cost index used in the Ontario calculations was, as noted above, a deflator for Canada's gas distribution capital stock prepared by Stats Canada.[42]

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

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

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

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

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

We restated this as

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

The first term in [A10] corresponds to the cost of depreciation. The second term captures the opportunity cost of capital ownership net of capital gains. The term in brackets is the

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

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

real rate of return on capital. This bracketed term was smoothed by taking a three year moving average of its values. The term I_t is the nominal rate of return to capital.

A.4.2 COS

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

Glossary of Terms

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

ck_t = Total non-tax cost of capital

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

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

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

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

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

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

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

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

N = Average service life of plant

WKS_t = Price of capital service

Basic Assumptions

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

Theory

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

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

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

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

where

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

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

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

The formula for the capital quantity index is thus

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

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

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

Equations [A11] and [A14] together imply that

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

where

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

It can be seen that the cost of capital is the product of a capital service price and a capital quantity index. The capital service price in a given year is a function of the construction cost index values in the *N* most recent years (including the current year). The importance of each WKA_{t-s} depends on the share, in the total amount of plant that contributes to cost, of plant remaining from additions in that year. This share is larger the more recent the plant addition year (since there is less depreciation) and the larger the plant additions in that year. Absent a decline in I, *WKS* is apt to rise each year as the WKA_{t-s} for each of the *N* years is replaced with the generally higher value for the following year. Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.[43]

A.5 TFP Growth Rates and Trends

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

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

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

A.6 Econometric Cost Research

In this study, an econometric cost model was used to provide weights for the output quantity indexes and to estimate a 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

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

O&M expenses. In this study, total cost models were developed to support the TFP research.

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

A.6.2 Form of the Cost Model

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

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

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

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

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. It is also noteworthy that in a double log model, the elasticities are *constant* across every value that the cost and business condition variables might assume.[44]

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

A more sophisticated translog functional form was used in the research supporting the first draft of this report.[45] This very flexible function is common in econometric cost research and, by some accounts, the most reliable of several available flexible forms.[46] Here is a cost function of translog form that is analogous to [A18] and [A19].

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

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each translogged business condition variable to differ at different values of the variable. This would permit the incremental economies of scale from output growth to diminish (or increase) at larger operating scales. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. In attempting to operationalize the use of company specific elasticities in our calculations, we discovered that the translog cost function generated some unreasonable values for these. We experimented with several alternative specifications and finally settled on one which differed from the translog form only in excluding the "output interaction" terms.

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

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

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

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45 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.

46 See Guilkey (1983), et. al.

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

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

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

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

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:

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

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

A.6.3 Estimating Model Parameters

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models using historical data on the dependent and explanatory variables.[47] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions they faced. The sample used in model estimation can be a time series (consisting of data over several years for a single firm), a cross section (consisting of one observation for each of several firms), or a panel data set that pools time series data for several companies. In this study we have employed panel data because such data are available and their use should enhance the precision of the parameter estimates.

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

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).[48] 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.[49] Since we estimated these unknown disturbance matrices consistently, our estimators are equivalent to Maximum Likelihood Estimators (MLE).[50] Our estimates thus possess all the highly desirable properties of MLEs.

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.[51] 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.

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[48] See Zellner, A. (1962)

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

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

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

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 each 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 these models, we have specified input price variables for capital, labour, and other O&M inputs. These are the same input price variables used in the TFP research. We expect cost to be higher the higher are the values of these variables.

Other Explanatory Variables

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

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

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.

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

Estimation Results

Estimation results for the models developed using GD and COS costing are reported in Tables 19a and 19b, respectively. In both tables, the parameter values for the additional business conditions and for the first order terms of the 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 tables shade the results for these useful elasticity estimates 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.

We examine here the results for COS costing. The results for GD costing are quite similar. It can be seen in Table 19b that all of the key cost function parameter estimates were statistically significant. Moreover, all were plausible as to sign and magnitude. With regard to the first order terms of the translogged variables, cost was found to be higher the higher were the input prices and the two output quantities. At sample mean values of the

Table 19a

Econometric Model of Gas Utility Base Rate Cost: Geometric Decay

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	0.229	15.69	**VRC**	0.188	5.74
LL	-0.314	-2.42	VRCVRC	-0.157	-3.81
LK	-0.090	-6.43			
LN	0.035	3.01			
LVRC	-0.054	-5.09	**VO**	0.052	2.61
LVO	0.008	2.16	VOVO	0.020	1.42
LTrend	0.000	-0.04			
			NIM	-0.474	-8.87
K	0.563	92.84			
KK	0.152	11.31	**NE**	-0.010	-8.60
KN	-0.101	-6.95			
KVRC	0.082	5.97	**UD**	0.041	2.67
KVO	0.024	6.00			
KTrend	0.006	6.44	Trend	-0.012	-4.98
N	0.633	15.40	Constant	8.166	329.06
NN	0.058	1.61			
			System Rbar-Squared	0.970	
			Sample Period	1994-2004	
			Number of Observations	396	

Table 19b

Econometric Model of Gas Utility Base Rate Cost
Cost of Service

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
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	0.244	15.52	**VRC**	0.143	4.17
LL	-0.343	-2.45	VRCVRC	-0.168	-3.91
LK	-0.096	-6.75			
LN	0.018	1.46			
LVRC	-0.041	-3.59	**VO**	0.048	2.40
LVO	0.015	3.44	VOVO	0.023	1.64
LTrend	0.000	0.07			
			NIM	-0.507	-8.94
K	0.532	85.67			
KK	0.158	11.59	**NE**	-0.010	-8.43
KN	-0.063	-4.48			
KVRC	0.045	3.38	**UD**	0.036	2.45
KVO	0.015	3.73			
KTrend	0.007	6.60	Trend	-0.014	-6.02
N	0.680	16.11	Constant	8.104	327.18
NN	0.069	1.83			
			System Rbar-Squared	0.968	
			Sample Period	1994-2004	
			Number of Observations	396	

business condition variables, a 1% increase in the number of customers raised cost by 0.68%.

A 1% hike in residential and commercial volume raised cost by about 0.14%. A 1% hike in the volume of other deliveries raised cost by about 0.05%. The number of customers served was clearly the dominant output-related cost driver. The sum of the elasticities of the output variables was 0.87. This means that simultaneous 1% of growth in all three output dimensions would raise total cost by only 0.87% for a firm with a sample mean operating scale.

The results suggest, importantly, that the scale economies available from incremental output growth actually increase with operating scale. This is due to the negative (and highly significant) sign on the quadratic residential and commercial delivery volume parameter and likely reflects special economies in the delivery of volumes over piping systems. Since Enbridge and Union are both large companies facing brisk output growth, they both have excellent opportunities to realize scale economies and this should materially bolster their productivity growth.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was about 0.53%. This was more than double the estimated elasticity of the price of labour. This comparison reflects the capital intensiveness of the gas distribution business.

The table also reports the system R^2 statistic for the model. This measures the ability of the model to explain variation in the sampled costs of distributors. Its value was 0.968, suggesting that the explanatory power of the model was high.

A.7 Mathematical Basis for the Proposed Price Cap Index

A.7.1 Glossary of Terms

For a given utility or group of utilities let:

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

W = Index of growth in the prices paid for inputs

X = Index of growth in the amounts of inputs used

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

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

Cost = Total Cost of Service

Revenue = Total Revenue

Δ = Growth Rate

A.7.2 Basic Divisia Index Logic

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

$$\Delta Revenue = \Delta Cost \quad \text{[A26]}$$

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

$$\Delta Cost = \Delta W + \Delta X \quad \text{[A27]}$$

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

$$\Delta Revenue = \Delta P + \Delta Y^R \quad \text{[A28]}$$

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

$$\begin{aligned} \Delta P &= \Delta W - (\Delta Y^R - \Delta X) \\ &= \Delta W - \Delta TFP^R \quad \text{[A29]} \end{aligned}$$

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,

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

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

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

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[A30] and [A31] together imply that:

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

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

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

A.7.3 Decomposing TFP ^{R}

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

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

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

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

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

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

A.7.4. Rationale for Service-Specific PCIs

<u>Stating the Problem</u>

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

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

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where

$R =$ total revenue

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

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

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

The growth rate formula for the summary PCI is

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

Recalling relations [10] and [A30], this can be simplified without loss of generality to[52]

$$\begin{aligned} \Delta PCI &= \Delta GDPIPI - [\Delta TFP^{R} + (GDPIPI - \Delta W) + Stretch] \\ &= GDPIPI - \left[\Delta TFP^{R} + A\right] \end{aligned} \quad \text{[A36]}$$

where

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

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

$Y^{R} =$ revenue-weighted output index

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

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

$X =$ cost-weighted input quantity index

$C_j =$ cost of input group j

$X_j =$ quantity of input j

$\Delta W =$ input price index weighted by the costs actually incurred

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_{ℓ} is the price cap index for service group ℓ, we seek a set of price cap indexes such that

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

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

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

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

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

Contributions from Cost Theory

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

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

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

$$\begin{aligned} \Delta Y^R &= \sum_\ell \frac{R_\ell}{R} \sum_i \frac{R_{i\ell}}{R_\ell} \cdot \Delta Y_{i\ell} \\ &= \sum_\ell \frac{R_\ell}{R} \Delta Y_\ell^R . \end{aligned}$$

In words, output growth is a revenue weighted average of growth in the output indexes for the individual service groups. [53]

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

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

so that

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

Totally differentiating each side with respect to time we find that

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

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

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

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

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

Equations [A41] and [A42] imply that

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

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

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

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

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

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

$$\Delta TFP^R = \sum_\ell \frac{R_\ell}{R} \Delta Y_\ell^R - \sum_\ell \sum_i \varepsilon_{i\ell} \cdot \Delta Y_{i\ell}. \qquad [A46]$$

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

The ADJ Factor

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

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

The TFP growth that would result if the utility offered only group ℓ services may be written

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

Relations [A46] and [A47] imply that the difference between ΔTFP_ℓ and ΔTFP is then

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

It can be seen that we have decomposed the difference between ΔTFP_{ℓ} and ΔTFP into a *revenue* effect and a *cost* effect. The indicated adjustment to the X factor for a particular service group will then be more negative to the extent that it has a disproportionately *small* impact on *revenue* and a disproportionately *large* impact on *cost*.

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

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

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

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

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

Operationalizing the Theory

How do we operationalize [A48]? If the marginal cost of each billing determinant i is the same for each service group ℓ, then for any Y_i and $Y_{i\ell}$

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

and

$$\begin{aligned}
\sum_{\ell} \sum_{i} \varepsilon_{i\ell} \Delta Y_{i\ell} &= \sum_{\ell} \sum_{i} \frac{\partial g}{\partial Y_i} \frac{Y_{i\ell}}{C} \Delta Y_{i\ell} \\
&= \sum_{i} \frac{\partial g}{\partial Y_i} \frac{Y_i}{C} \sum_{\ell} \frac{Y_{i\ell}}{Y_i} \frac{1}{Y_{i\ell}} \frac{dY_{i\ell}}{dT} \\
&= \sum_{i} \varepsilon_i \frac{1}{Y_i} \frac{d\sum_{\ell} Y_{i\ell}}{dT} \\
&= \sum_i \varepsilon_i \frac{d \ln Y_i}{dT} \\
&= \sum_i \varepsilon_i \Delta Y_i \,.
\end{aligned}$$

The ADJ_ℓ formula then simplifies to

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

Estimates of the elasticities can be obtained for each company from our econometric cost research. Since

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

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, California. The chief satellite office is based in Madison, Wisconsin. Five principals of the company are PhD economists and three are current or former faculty members at respected universities. Founding partner Charles Cicchetti is a professor of economics at the University of Southern California. He was previously chair of Wisconsin's Public Service Commission and an economics professor at the University of Wisconsin. Founding partner Jeff Dubin is an economics professor at Cal Tech.

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

A.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 IR plans, and expert witness testimony. He holds a B.A. in Ibero-American studies and a Ph.D. in applied economics from the University of Wisconsin-Madison.

Over the years he has prepared numerous utility performance studies and developed many IR plans. He has testified or filed commentary 14 times on statistical benchmarking, and more than 20 times on industry productivity trends and other IR issues. The venues for this testimony have included California, 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 Spanish as well as English.

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

His career has also included work as an academic economist. He has served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. His academic research and teaching stressed the use of mathematical theory 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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Appendix G