The O&M Cost Performance of Enbridge Gas Distribution

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Executive Summary

Enbridge Gas Distribution made a filing last fall in support of cost-based rates for its gas delivery services. The reasonableness of its proposed non-gas operating and maintenance ("O&M") expenses is an issue in the proceeding. The Company has commissioned Pacific Economics Group to benchmark the cost efficiency of its O&M. We appraised efficiency using multifactor productivity ("MFP") level indexes and econometric benchmarking.

Research Methodology

Our research addressed the cost efficiency of Enbridge in managing its gas distribution O&M. Gas distribution services were defined to include local gas delivery, gas transmission and storage, and customer account and information services.

Our MFP index is based a ratio of an output quantity index to an input quantity index. It is used to make productivity comparisons involving multiple inputs. The econometric benchmarking approach allows us to assess O&M cost efficiency by fitting an O&M cost model with the business conditions faced by the Company.

The indexing work was based on a sample of data for 78 U.S. distributors while the econometric work is based on a sample of 41 U.S. gas companies. MFP indexes of the industry for the year 2000 were used to benchmark Enbridge's expense levels for the historical years 1999-2002 and test year 2003. The econometric O&M cost benchmark model, based on data from 1990 to 2000, was used to appraise the Company's O&M cost for the years 1999-2003.

Results

The O&M productivity levels of the company were well above the year 2000 mean for the sample throughout the historical 1999-2002 period. As for the 2003 test year expenses, we found that the productivity implicit in this proposal is about 32% above the full sample mean. These results suggest that the productivity implicit in the 2003 test year expenses proposed by Enbridge can be achieved on a sustained basis only with superior cost management. The econometric model shows Enbridge's predicted O&M cost to be 26% below the actual O&M cost over the five years.

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1. INTRODUCTION

Statistical benchmarking has in recent years become a widely used tool in utility performance assessment. Managers use benchmarking to assess their companies' operating efficiency. Benchmarking also plays a growing role in regulation. Such studies can, for instance, be used to assess the reasonableness of costs at the start of multiyear rate plans.

Performance appraisals are facilitated by the extensive data on costs and other aspects of their operations which utilities report to regulators and industry associations. However, accurate appraisals are still challenging. There are important differences between companies in the scale and mix of services provided, the prices of production inputs, and other business conditions that influence their cost. Data are unavailable for many companies and do not cover all relevant business conditions where they are available.

Pacific Economics Group ("PEG") personnel have been active for more than a decade in utility cost performance research. We pioneered the use of productivity measurement and scientific benchmarking in U.S. regulation. Our benchmarking practice is international in scope, and has included research for clients in Australia and Japan. Senior author and project leader Mark Lowry has testified on our work in numerous proceedings.

Enbridge Gas Distribution ("Enbridge" or "the Company") made a filing last fall in support of cost-based rates for its gas delivery services. The reasonableness of its proposed non-gas operating and maintenance ("O&M") expenses is an issue in the proceeding. The Company has commissioned Pacific Economics Group to benchmark the cost efficiency of its non-gas O&M. We appraised efficiency using multifactor productivity ("MFP") level indexes and econometric benchmarking.

This paper is a report on this work. Following a brief summary of the research, Section 2 discusses the data used in the study and our calculation of distribution cost. Section 3 discusses our indexing work. Our econometric work is discussed in Section 4. Additional, more technical research details are presented in the Appendix.

2. DATA ISSUES

2.1 Data

The primary source of the data used in our gas distribution cost research changed over the sample period. The *Uniform Statistical Report* (USR) was the primary source for the earliest years. Gas utilities are asked to file these reports annually with the American Gas Association (AGA). USR data for some variables are aggregated and published annually by the AGA in *Gas Facts*.

USRs are unavailable for many distributors today. Many do not file complete USRs. Some distributors that do file them do not release them to the public. The development of a satisfactory sample therefore required us to obtain basic cost and quantity data from alternative sources including, most notably, reports to state regulators. These reports often use as templates the Form 2 report that interstate gas transmission companies are required to file with the Federal Energy Regulatory Commission. Most data from these sources for the most recent years of the sample were obtained from OPRI, a commercial data vendor. Other sources of data were also used in the indexing research. These include R.S. Means, the Organization of Economic Cooperation and Development (OECD), Statistics Canada, the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, and Whitman, Requardt & Associates. The OECD and government data were obtained from the official websites.

We have compiled from these sources quality data for a sample of U.S. gas distributors. Data for the larger Canadian distributors were sought without success. The companies included in the final sample are listed in Table 1. It can be seen that data for 78 U.S. companies were employed in our index comparisons for Enbridge. The sample includes most of the larger U.S. gas distributors. Some of the sampled distributors provide gas transmission and/or storage services but all were involved more extensively in gas distribution. The table also indicates that the sampled distributors served about 69% of all gas end users in the United States. The table also notes that data for a smaller group of 41 utilities were used in the econometric work that was undertaken in output quantity index construction.

Table 1

SAMPLE FOR BENCHMARKING *

Region	Company	Number of Customers (2000)
Northeast		
	*Bay State**	283,602
	Boston Gas	542,792
	Brooklyn Union Gas	1,191,679
	Central Hudson Gas & Electric	63,851
	Columbia Gas of Pennsylvania	393,870
	Commonwealth Gas	243,853
	Connecticut Energy	164,012
	Connecticut Natural Gas	155,641
	Consolidated Edison	1,048,357
	Delmarva	100,791
	Equitable Gas	232,702
	National Fuel Distribution	736,213
	New Jersey Natural Gas	414,620
	New York State Electric & Gas	246,453
	Niagara Mohawk	544,075
	Orange & Rockland Utilities	118,718
	PECO	430,842
	People's Natural Gas	353,715
	PG Energy	155,992
	Providence Energy	172,965
	Public Service Electric & Gas	1,621,128
	Rochester Gas & Electric	285,944
	South Jersey Gas	281,350
	UGI Utilities	272,825
	Yankee Gas Services	181,400
South Atlantic		
	Atlanta Gas Light	1,530,000
	Baltimore Gas & Electric	595,239
	Columbia Gas of Virginia	181,083
	Hope Gas	115,165
	Mountaineer Gas	204,867
	North Carolina Natural Gas	117,162
	Piedmont Natural Gas	514,126
	Public Service of North Carolina	357,736
	South Carolina Electric & Gas	262,024
	Washington Gas Light	868,362
South Central		
	Alabama Gas	465,656
	Columbia Gas of Kentucky	128,793
	Louisville Gas & Electric	297,717
	Mobile Gas Service	99,765
	Oklahoma Natural Gas	757,688
	Union Light Heat & Power	83,311

Region	Company	Number of Customers (2000)
North Central		
	AmerenCIPS	169,141
	Central Illinois Light	205,375
	Cincinnati Gas & Electric	348,187
	Citizens Gas & Coke	265,450
	Consumers Power	1,594,484
	East Ohio Gas	1,234,854
	Illinois Power	399,361
	Indiana Gas	563,212
	Interstate Power	50,270
	Kansas Gas Service	663,319
	Laclede Gas	632,593
	Madison Gas & Electric	113,781
	Michigan Consolidated Gas	1,150,636
	MidAmerican Energy	643,339
	Montana Power	153,905
	Northern Indiana Public Service	698,063
	North Shore Gas	*149,032*
	Peoples Gas Light & Coke	840,560
	Wisconsin Electric Power	402,525
	Wisconsin Gas	*540,676*
	Wisconsin Power & Light	157,077
	Wisconsin Public Service	226,839
Southwest		
	Mountain Fuel Supply	705,878
	PNM	436,865
	Public Service of Colorado	1,082,591
	Sierra Pacific Power	111,939
	Southwest Gas	1,289,046
Northwest	Avista	273,092
	Cascade Natural Gas	193,160
	Enstar Natural Gas	102,537
	Intermountain Gas Co	213,423
	Northwest Natural Gas	510,686
	Washington Natural Gas	580,283
California	Pacific Gas & Electric	3,746,414
	San Diego Gas & Electric	756,053
	Southern California Gas	5,008,579
Texas		
	Enserch	1,415,296
Canada		
	Enbridge Gas Distribution	1,465,000

Number of Companies in Indexing Sample	79
Number of Companies in Econometric Sample	42

Total for U.S. Sample	44,444,605
U.S. Industry Total **	64,804,630
Percentage of U.S. Total	68.6%

*Companies that have traditionally provided gas distribution service but not electrictiy service are italicized.
**Source For US Total: U.S. Energy Information Administration, *Natural Gas Annual 2000*

Year 2000 data were used in the productivity comparison. This is the latest year for which data for a large number of distributors are as yet available. U.S. data for the longer 1990-2000 period were used in econometric research that we undertook in output quantity index construction.

2.2 Definition of Cost

2.2.1 Applicable Cost

Cost figures play an important role in productivity research. Our approach to calculating cost is therefore important. The applicable cost for benchmarking was calculated as total gas operation and maintenance ("O&M") expenses less gas production and purchase expenses, franchise fees, and any expenses for off system transmission services. The operations corresponding to this cost definition include gas transmission, storage, local delivery, customer account, and information and other customer services of distributors.

The econometric work supporting output quantity index construction required, in addition, an estimate of the capital cost of each distributor. The study used a service price approach to measuring the cost of plant ownership. Under this approach, the cost of capital is the product of a capital quantity index and the price of capital services. This method has a solid basis in economic theory and is well established in the scholarly literature. Further details of our capital cost calculations are provided in Section 2.3 of the Appendix.

2.2.2 Cost Decomposition

The benchmarking involved the decomposition of O&M expenses into two input categories: labor services and non-labor O&M inputs. The cost of labor is defined as the sum of O&M salaries and wages and pensions and other employee benefits. The cost of other O&M inputs is defined to be assigned O&M expenses net of these labor costs. This input category includes the services of contract workers, insurance, rented real estate and equipment, and miscellaneous materials.

3. MFP RESEARCH

3.1 An Overview of the Method

This section provides a substantially non-technical overview of the indexing methods employed in this study. Additional, more technical details of the work are found in Section A.2 of the Appendix.

A multi-factor productivity index (*MFP*) is the ratio of an output quantity index to an input quantity index (*Input Quantity*).

$$MFP = \frac{Output\ Quantity}{Input\ Quantity}. \qquad [1]$$

It is used to make productivity comparisons that involve multiple inputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time.

An output quantity index provides a summary comparison of the amounts of goods and services produced. An input quantity index provides a summary comparison of the quantities of production inputs used. An MFP index is thus higher to the extent that the input quantity comparison is small relative to the output quantity comparison. Suppose, by way of example, that Utility A produces the same amount of output as Utility B with 10% less input. The MFP of Utility A is then about 11% above that of Utility B.

An MFP index captures the percentage difference in the unit cost of sampled distributors that was not due to the percentage difference in the input prices that they faced. To see this, suppose that a distributor's cost is the product of its input quantity index and an index of the prices that it pays for inputs (*Input Price*).

$$Cost = Input\ Price \cdot Input\ Quantity. \qquad [2]$$

Then

$$\begin{aligned} Unit\ Cost &= \frac{Input\ Price \cdot Input\ Quantity}{Output\ Quantity} \\ &= \frac{Input\ Price}{\left(\dfrac{Output\ Quantity}{Input\ Quantity}\right)} \\ &= \frac{Input\ Price}{MFP}. \end{aligned} \qquad [3]$$

Unit cost will be lower the lower are input prices and the higher is MFP.

This discussion helps to explain the usefulness of MFP indexes as performance benchmarks. The use of data from other distributors to evaluate cost performance is complicated by differences in the business conditions that they face. MFP indexes can be viewed as comparisons of the costs incurred by companies which control for differences in two sets of business conditions that can vary between them and are major cost drivers: the amount of work performed and the prices paid for inputs. These extensive controls permit us to use data for distributors facing heterogeneous demands and input prices in evaluating the cost performance of Enbridge.

Despite these advantages, MFP comparisons do not control for all of the cost drivers that are thought to explain variations in distributor cost. As one example, distributors are apt to have higher productivity the larger is their operating scale due to the realization of scale economies. As another, gas distributors who also deliver power to customers are apt to have higher productivity than those who do not. Enbridge is one of the larger gas distributors in North America but is not a power distributor. To provide better benchmarks for Enbridge, we therefore compared its productivity levels to the 2000 norms for gas only utilities and for large gas only utilities in addition to the comparison to the full sample norm. Large gas utilities were defined as those serving at least 1,000,000 customers. These peer groups are sensible ones that strike a balance between the desires for numerous peers and for a full set of controls for the business conditions that are known to reflect gas distribution cost.

3.2 MFP Results

Tables 2 and 3 present results of the MFP comparisons. Details of the MFP calculations appear in Table 2. The results for 2003 may serve to illustrate index calculation. We find that the Company's predicted output is 2.87 times the full sample mean while the input

Table 2

MFP Level Indexes for Gas Distribution: 1999-2003

	Output Quantity Index	Input Quantity Index	MFP Index	Percentage Difference from Sample Mean MFP *
1999	2.565	1.978	1.296	26.0%
2000	2.664	1.678	1.588	46.2%
2001	2.751	1.796	1.531	42.6%
2002	2.799	1.705	1.642	49.6%
2003	2.872	2.084	1.378	32.1%

* Percentages are calculated using logarithims.

Table 3

How Enbridge MFP Compares to Averages For Selected Peer Groups

	Gas-Only Distributors (45 companies)	**> 1,000,000 Customers, Gas Only (7 companies)**
	How Enbridge Compares[1]	How Enbridge Compares[1]
1999	36.50%	26.77%
2000	56.77%	47.05%
2001	53.16%	43.44%
2002	60.15%	50.43%
2003	42.61%	32.88%

[1] Percentages are calculated logarithims

Figure 1

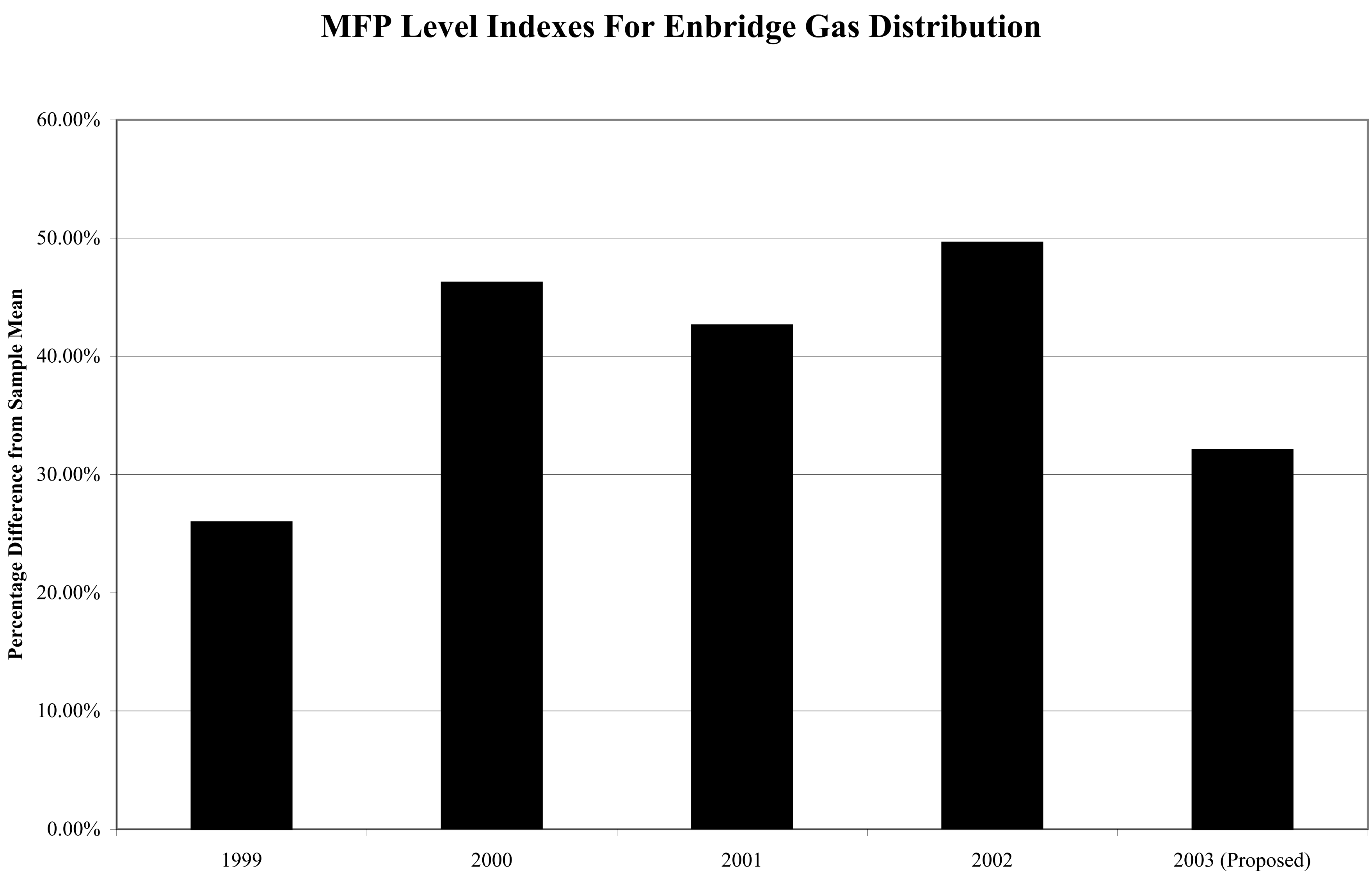
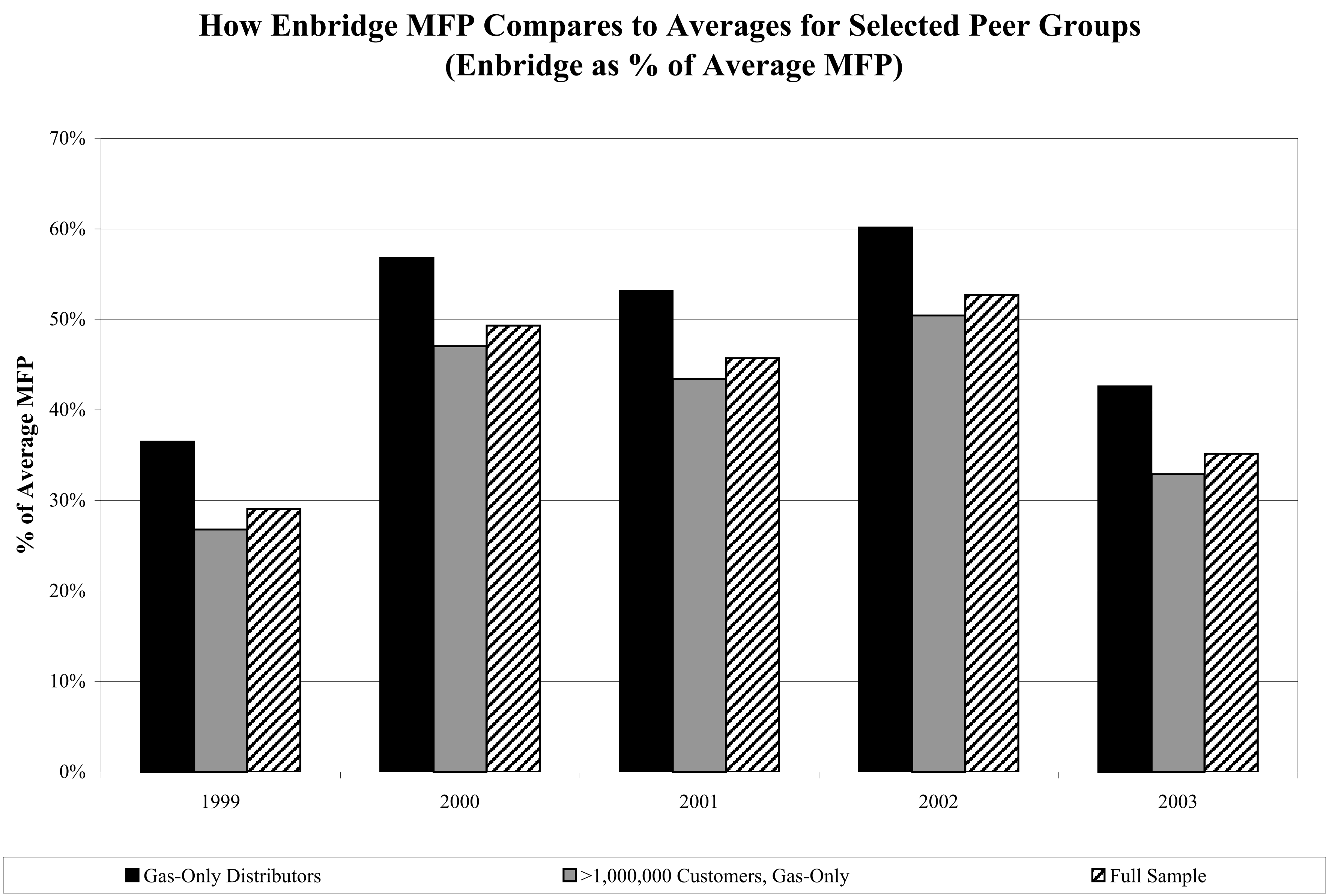

MFP Level Indexes For Enbridge Gas Distribution
Percentage Difference from Sample Mean
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
1999
2000
2001
2002
2003 (Proposed)

Figure 2


How Enbridge MFP Compares to Averages for Selected Peer Groups
(Enbridge as % of Average MFP)
70%
60%
50%
40%
30%
20%
10%
0%
% of Average MFP
1999
2000
2001
2002
2003
Gas-Only Distributors
>1,000,000 Customers, Gas-Only
Full Sample

quantity implicit in its cost projection is only 2.08 times the mean. These numbers produce an MFP index 1.38 times the mean. The productivity implicit in the proposed Enbridge expenses is thus about 32% above the full sample mean. This performance would have placed Enbridge eleventh out of 78 companies were it added to the full sample, clearly a top quartile performance.

Table 3 presents MFP results for the sample subgroups that are useful peers in an Enbridge evaluation. The table shows that the MFP of Enbridge compared favorably to the mean for both subgroups in all four years of the historical 1999-2002 period. As for the 2003 test year numbers, we find that the productivity of Enbridge was an impressive 33% above the mean for large gas only utilities and 43% above the mean for all gas only utilities. Its hypothetical performance would rank it first out of eight (including Enbridge) large gas only utilities. The results suggest that the Company's 2003 test year expenses can be achieved only with superior cost management.

4. ECONOMETRIC RESEARCH

4.1 An Overview of the Method

This section provides a substantially non-technical account of the econometric approach to benchmarking employed in this study. Additional, more technical details of the work are reported in the Appendix.

A mathematical model called a cost function was specified. Cost functions represent the relationship between the cost of a utility and quantifiable business conditions in its service territory. Business conditions are defined as aspects of a company's operating environment that affect its activities but cannot be controlled.

Economic theory was used to guide cost model development. We posited that the actual total cost (C_i) incurred by company, i, in service provision is the product of minimum achievable cost (C_i^*) and an efficiency factor ($efficiency_i$). This assumption can be expressed logarithmically as

$$\ln C_i = \ln C_i^* + \ln efficiency_i .[1] \qquad [4]$$

The term ln indicates the natural log of a variable.

According to theory, the minimum total cost of an enterprise is a function of the amount of work it performs and the prices it pays for capital, labor, and other production inputs. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, cost is apt to be higher the higher are input prices and the greater is the amount of work performed.

Here is a simple example of a minimum total cost function for power distribution that conforms to cost theory.

$$\ln C = \alpha_0 + \alpha_1 \cdot \ln N_{i,t} + \alpha_2 . \cdot \ln W_{i,t} + u_{i,t} . \qquad [5]$$

For each firm i in year t, the variable $N_{i,t}$ is the number of customers that the company serves. It quantifies one dimension of the work that it performs. The variable $W_{i,t}$ is the

[1] The logarithm of the product of two variables is the sum of their individual logarithms.

wage rate that the company pays. The wage rate and number of customers are the measured business conditions in this cost function.

The term $u_{i,t}$ is the error term of the minimum cost function. This term reflects any errors in the specification of the model, including problems in the measurement of output and other business condition variables and the exclusion from the model of any relevant business conditions. It is customary to assume a specific probability distribution for the error term that is determined by additional parameters, such as mean and variance.

Combining the results of Equations [4] and [5] we obtain the following model of cost:[2]

$$\ln C_{i,t} = \alpha_0 + \alpha_i \cdot \ln N_{i,t} + \alpha_2 . \cdot \ln W_{i,t} + e_{i,t}. \qquad [6]$$

Here the *actual* (not minimum) total cost of a utility is a function of the two measured business conditions. The terms α_0, α_1, and α_2 are model parameters. Their values are assumed to be constant across companies and over some period of time. The α_0 parameter captures the efficiency factor for the average firm in the sample as well as the value of α_0 from the minimum total cost function. The values of α_1 and α_2 determine the effect of the two measured business conditions on cost. If the value of α_2 is positive, for instance, an increase in wage rates will raise cost.

The term $e_{i,t}$ is the error term for equation [6]. We assume that it is a random variable. It includes the error term from the minimum total cost function. It also reflects the extent to which the Company's efficiency factor differs from the sample norm.

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models. Cost model parameters can be estimated econometrically

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

$$\begin{aligned}
\ln C_{i,t} &= \ln C^*_{i,t} + \ln \mathit{efficiency}_i \\
&= \left(\alpha_0 + \alpha_1 \cdot \ln N_{i,t} + \alpha_2 . \cdot \ln W_{i,t} + u_{i,t}\right) + \ln \mathit{efficiency}_i \\
&= \left(\alpha_0 + \ln \mathit{efficiency}^{average}\right) + \alpha_1 \ln N_{i,t} + \alpha_2 . \cdot \ln W_{i,t} \\
&\quad + \left[u_i + \left(\ln \mathit{efficiency}_i - \ln \mathit{efficiency}^{average}\right)\right] \\
&= \alpha_0 + \alpha_1 \cdot \ln N_{i,t} + \alpha_2 . \cdot \ln W_{i,t} + e_{i,t}
\end{aligned}$$

using historical data on the costs incurred by utilities and on the business conditions they faced. For example, a positive estimate for α_2 would reflect the fact that the cost reported by sampled companies was typically higher when higher wages were paid to employees.

Numerous statistical methods have been established in the econometrics literature for estimating parameters of economic models. In choosing among these, we have been guided by the desire to obtain a good model for cost benchmarking. Econometric methods are useful in selecting business conditions for the model. Tests are available for the hypothesis that the parameter for a business condition variable equals zero. Variables were excluded from the model when such hypotheses could not be rejected.

4.2.2 O&M Cost Benchmarking

We use our econometric cost model to appraise Enbridge's O&M cost. Such an appraisal is based on an econometric O&M cost benchmark model. We develop this model by fitting an O&M cost function with econometric parameter estimates. The O&M cost function is based on that portion of total cost that is attributed to and explained by business condition variables that affect O&M activity. We use this model to predict a company's O&M cost given the values of the company's business condition variables that affect O&M activity.

Returning to our example, we might predict the (logged) O&M cost of Enbridge in period *t* as follows:[3]

$$\ln \hat{C}^{OM}{}_{Enbridge,t} = \hat{\alpha}_0 + \hat{\alpha}_i \cdot \ln N_{Enbridge,t} + \hat{\alpha}_2 . \cdot \ln W_{Enbridge,t} . \quad [7]$$

Here $\hat{C}^{OM}{}_{Enbridge,t}$ denotes the predicted O&M cost of the Company in period *t*, $N_{Enbridge,t}$ is the number of customers it served, and $W_{Enbridge,t}$ is the wage rate that it paid. The $\hat{\alpha}_0$, $\hat{\alpha}_1$, and $\hat{\alpha}_2$ terms are parameter estimates.

If the parameter estimates are accurate and the value of the error term is zero, the percentage difference between the Company's actual O&M cost and that predicted by the

[3] Since this is a predicted equation using estimated parameters there is no error term.

model is the percentage difference between the O&M efficiency factor of the Company and that of the sample mean firm.

$$\ln\left(C^{OM}{}_{Enbridge,t} \Big/ \hat{C}^{OM}{}_{Enbridge,t} \right) = \ln\left(efficiency_{Enbridge} \Big/ efficiency_{average} \right). \qquad [8]$$

This percentage difference is a measure of the Company's O&M cost performance.

An O&M cost prediction like that generated in the manner just described is our best *single* guess of the Company's O&M cost given the business conditions that it faces. This is an example of a point prediction. An important characteristic of the econometric approach to O&M benchmarking is that the statistical results provide information about the *precision* of such point predictions. According to econometric theory, precision is greater to the extent that:

- The model is more successful in explaining the variation in O&M cost in the sample
- The size of the sample is larger
- The number of business condition variables included in the model is smaller
- The business conditions of sample companies are more varied
- The business conditions of the subject company are closer to those of the typical firm in the sample

We assess the precision of a company's O&M cost prediction based on a routine application of forecast variance. This variance, which tells us about the statistical significance of our point prediction, is essentially the pre and post multiplication of the covariance matrix of the parameter estimates by a vector of the explanatory or business condition variables.

4.3 Econometric Results

Estimation results for the cost model are reported in Table 4. The parameter values for the additional business conditions and for the first order terms of the variables are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The table shades the results for these terms for reader convenience.

The table also reports the values of the asymptotic *t* ratios that correspond to each parameter estimate. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed a critical value that is appropriate for a 90% confidence level given a large sample. The critical value was 1.645. The *t* ratios were used in model specification. The output quantities and input prices (which were translogged in model specification) were required to have first order terms with plausibly signed and statistically significant parameter estimates. The parameters of the other variables (which were not translogged) were also required to have statistically significant estimates.

Examining the cost function results in Table 4, it can be seen that the parameter estimates were plausible as to sign and magnitude. With regard to the first order terms, cost was found to be higher the higher were input prices and output quantities. At the sample mean, a 1% increase in the number of customers raised cost by 0.70%. A 1% hike in

Table 4

Translog Cost Function Regression Results: Gas Delivery

Variable Key*

L= Labor Price
K= Capital Price
N= Number Customers
V= Total Throughput
NE= Number of Electric Customers
CI= % Non-Iron and Unprotected Bare Steel in Distribution Miles
Q= Earthquake Dummy
F= Frost Depth Index
T= Trend

Explanatory Variable	Estimated Coefficient	t-Statistic**
WL	0.2047	41.36
LL	-0.0894	-2.34
LK	-0.0311	-1.25
LN	0.0180	2.21
LV	-0.0206	-2.54
WK	0.6573	110.59
KK	0.1427	4.71
KN	-0.0322	-3.40
KV	0.0298	3.08
N	0.7046	19.53
NN	-0.3774	-4.16
NV		
V	0.1695	4.94
VV	-0.3954	-3.50

Explanatory Variable	Estimated Coefficient	t-Statistic**
NE	-0.0101	-8.06
NEL	-0.0004	-0.93
NEK	0.0026	5.51
CI	-0.1117	-3.81
CIL	-0.0493	-4.31
CIK	0.0509	3.87
Q	0.0087	1.72
QL	-0.0040	-2.46
QK	0.0035	1.73
F	-0.0537	-2.60
FL	0.0049	0.74
FK	0.0278	3.52
T	-0.0041	-1.63
TL	-0.0068	-7.41
TK	0.0066	6.00
Constant	7.9692	450.89
System Rbar-Squared		0.969
Number of Observations		451

*Data for all variables were logged and mean-scaled prior to model estimations
**The Critical Value for t-Statistic is 1.645.

throughput raised cost by about 0.17%. The number of customers accounted for about 81% of the sum of the estimated output quantity elasticities. This figure was used in output quantity index construction. The number of customers served was clearly the dominant output-related cost driver.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was 0.66%. This was more than three times the estimated elasticity of the price of labor. This comparison reflects the capital intensiveness of the gas distribution business.

The parameter estimates for the first order terms of the additional variables in the cost function were also sensible.

- Total cost was lower the greater was the percentage of distribution mains not made with cast iron and bare steel.
- Cost was lower the greater were the number of electric customers served by a distributor.
- Cost was higher the greater was maximum frost depth and earthquake risk.
- The estimate of the trend variable parameter was -0.41% and was highly significant. This suggests a gradual downward shift in the cost function.

4.4 O&M Benchmarking Results

Table 5 presents the results of our appraisal of Enbridge's O&M cost using the econometric model. The parameter estimates of the model are based on data from 1990-2000, while the company's predicted O&M cost is based on five years of data covering 1999-2003. Data for 2003 are projected business conditions and an O&M expense allowance of $280.9 million, which includes an amount budgeted for demand side management[4]. The Company's average O&M cost during the five-year sample period is about 27% below its predicted value. The hypothesis that the company is an average (or inferior) cost performer was rejected at the 95% confidence level. This result ranks eighth best among the 41 sampled companies. Table 5 also presents the Company's O&M cost efficiency for the test year of 2003 based on the above noted O&M expense allowance. Given projections of business conditions that company would face, its predicted O&M cost is below the allowed O&M expense by 22%. This prediction is statistically significant at the 90% confidence level.

[4] Source: Settlement Proposal, Filed 2003-03-14, RP-2002-0133, Exhibit 1N, Tab 1, Schedule 1.

Table 5

ACTUAL AND PREDICTED COST FOR GAS DISTRIBUTION

	Actual Cost $1000	Predicted Cost $1000	Difference (%)*	t-statistic
1999-2003	254,231	334,034	-27.3%	-1.686
2003	280,969	348,363	-21.5%	-2.144

* Percent difference based on natural logs.

APPENDIX:
FURTHER DETAILS OF THE BENCHMARKING RESEARCH

This Appendix provides additional and more technical details of our benchmarking work. We first consider details of index construction. There follows a discussion of the supporting econometric work.

A.1 Index Research

This section contains further details of our index research. Sub-Section 1.1 discusses the output quantity indexes. Sub-Section 1.2 discusses the formula for the input quantity indexes. Sub-Sections 1.3 and 1.4 address input price and quantity subindexes.

A.1.1 Output Quantity Level Indexes

The output quantity level index for each company *i* in the U.S. sample is defined by the formula

$$\ln \text{Output Quantity}_{\text{i,t}} = \sum_h S_h^E \cdot \ln\left(Y_{i,h,t} \big/ \overline{Y}_{h,s} \right). \qquad [9]$$

Here in each period *t*,

$Y_{i,h,t}$ = Quantity of output dimension *h* for company *i*

$\overline{Y}_{h,s}$ = Mean quantity of output dimension *h* used by all sampled utilities in base year s

S_h^E = Share of output dimension *h* in the sum of the econometric estimates of the cost elasticities of the output quantities.

The shares resulting from the econometric work for the number of customers and throughput were .81% and .19%, respectively. These shares reflect the result, discussed below, that the number of customers served was identified in the econometric work to be the dominant output-related cost driver. Recall that the base year was 2000. Results for Enbridge were computed analogously save that Enbridge figures were not used in the calculation of the sample mean.

A.1.2 Input Quantity Level Indexes

The input quantity level indexes used in the study for U.S. companies are of bilateral Tornqvist form. The formula for each such index may be stated formally as

$$\ln \text{Input Quantity}_{i,t} = \sum_j \tfrac{1}{2} \cdot \left(S_{i,j,t} + \overline{S}_{j,s}\right) \cdot \ln\left(X_{i,j,t} / \overline{X}_{j,S}\right). \qquad [10]$$

Here in each year *t*,

$Input\ Quantity_{i,t}$	=	Input quantity index for company *i*
$X_{i,j,t}$	=	Quantity of input *j* used by company *i*
$\overline{X}_{j,s}$	=	Mean quantity of input *j* used by all sampled companies in base year s
$S^{C}_{i,j,t}$	=	Share of input category *j* in the applicable O&M expenses of company *i*
$\overline{S}^{C}_{j,s}$	=	Mean share of input category *j* in the applicable total cost of all sampled companies in base year s.

It can be seen that each index is a weighted average of comparisons of the input quantities used by the subject company to the mean of the input quantities used by all sampled distributors. Each comparison takes the form of the logarithm of the ratio of the quantities. The weight assigned to each quantity comparison is the average of the cost share for the subject distributor and the corresponding mean of the cost shares for all sampled distributors. Results for Enbridge were computed analogously save that Enbridge figures were not used to compute the base year mean quantities or cost shares.

A.1.3 Input Prices

Input price indexes were used in input quantity index construction. The labor price variable used in this study was constructed by PEG using data from the BLS. National Compensation Survey ("NCS") data for 1998 were used to construct average wage rates that correspond to each distributor's service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sector for the U.S. as a whole. For U.S. companies, values for other years were calculated by adjusting the 1998 level for changes in regional indexes of employment cost trends for the EGS sector. These indexes were also constructed from BLS data.

The construction of a labor price index value for Enbridge involved several steps. For the years 1999 and 2000, we first calculated the ratio in that year of the average weekly earnings of a Canadian worker engaged in the utility industry to the corresponding average for the U.S. The data were obtained from BLS and Stats Canada. We next calculated the ratio of the average earnings of the population 15 years and over in Toronto in 1995 to the corresponding figure for Canada as a whole. These data were also obtained from Stats Canada. The labor price index value for Enbridge was then calculated as product of these two ratios and the average index value for the U.S. sample. For the years 2001 and 2002, we multiplied the average index value for the U.S. in those years to the same two ratios. For 2003, we updated the index number thus calculated using its 2002 value and the average annual growth rate of the Enbridge values from 1999 to 2002.

Prices for other O&M inputs were assumed to be the same in a given year for all U.S. companies. They were escalated by the U.S. gross domestic product price index. Our general approach to the computation of the price index for capital services, which was used in the econometric work, is described in Appendix Section 2.3.

The construction of the corresponding index value for Enbridge was undertaken as follows. We calculated the values for the 1999-2002 period as the product of the index just described and a purchasing power parity for the Canadian economy. The purchasing power parities were obtained from the OECD. The year 2002 is the latest for which they are as yet available. For the 2003 test year, we took the 2002 input price index value thus calculated and multiplied it by the average annual growth rate in the Enbridge values from 1999-2002.

A.1.4 Input Quantity Subindexes

Each quantity level subindex for labor was the ratio of salaries and wages to the labor price index discussed above. Each quantity level subindex for the miscellaneous other gas delivery O&M inputs was the ratio of non-labor O&M expenses to the corresponding price index, discussed above.

A.2 Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog. This very flexible function is the most frequently used in econometric cost research, and is by some accounts the most reliable of several available alternatives.[5] The general form of the cost function used in this study is:

$$\begin{aligned}
\ln C = {} & \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j + \sum_k {}_k \ln Z_k + \alpha_t T \\
& + \frac{1}{2}\left[\sum_h \sum_m \gamma_{hm} \ln Y_h \ln Y_m + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n \right] \\
& + \sum_h \sum_j \gamma_{hj} \ln Y_h \ln W_j + \sum_k \sum_j \gamma_{kj} \ln Z_k \ln W_j + \sum_j \gamma_{tj} \, T \ln W_j .
\end{aligned} \qquad [11]$$

Here, Y_h denotes any of several variables that quantify output, W_j denotes any of several input prices, and Z_k denotes any of several additional business conditions. T is a trend variable. Notice that to simplify the model the Z variables and the trend variable are interacted only with the input price variables and have no quadratic terms.

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the possible values of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at larger values of the variable than at smaller ones. This type of relationship between cost and quantity is often found in cost research.

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

$$\sum_j^N \frac{\partial \ln C}{\partial \ln W_j} = 1 \qquad [12]$$

$$\sum_h^N \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots, N \qquad [13]$$

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[5] See, for example, Guilkey (1983), et. al.

$$\sum_{h}^{K} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1,..., K \tag{14}$$

Estimation of the parameters of the cost function is now possible but this approach does not utilize all 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:

$$S_j = \alpha_j + \sum_n \gamma_{jn} \ln W_n + \sum_h \gamma_{hj} \ln Y_h + \sum_k \gamma_{kj} \ln Z_k + \sum_j \gamma_{tj} T. \tag{15}$$

Note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come to no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

We used a "seemingly unrelated" regression procedure to estimate the cost function parameters that is due to Zellner (1962).[6] It is well known that if there exists 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 iterated this procedure to convergence.[7] Since we estimated these unknown disturbance matrices consistently, the estimators we eventually computed are equivalent to Maximum Likelihood Estimation (MLE).[8] Our estimates thus possess all the highly desirable properties of MLE's.

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

[6] See Zellner, A. (1962)
[7] That is, we iterate the procedure until the determinant of the differences between any two consecutive estimated disturbance matrices are approximately zero.
[8] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

observation, one cost share equation is redundant and must be dropped.[9] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

A.2.3 Capital Cost

Capital cost must, as discussed above, be calculated for use in cost model estimation. A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[10] It facilitates the use of benchmarking of cost data for utilities with different plant vintages.

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 ($XK_{j,t-1}$).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [16]$$

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 constructing capital quantity indexes we took 1985 as the benchmark or starting year. The values for these indexes in the benchmark year are based on the net value of plant as reported in the USR. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by a weighted average of the values of an index of utility construction cost for a period ending in the benchmark year. Values were considered for a series of consecutive years with length equal to the lifetime of the relevant plant category.

The following formula was used to compute subsequent values of the capital quantity index:

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [17]$$

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

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

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The economic depreciation rate was calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category was derived from data reported by the BEA.

The construction cost index (WKA_t) for each U.S. firm was the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category. This was levelized using regional construction cost indexes from R.S. Means. The value of *WKA* for Enbridge for the years 1999-2000 was calculated as the average value of *WKA* for the U.S. firms in the sample times the ratio of the Toronto value of the Means index to the value for a 30 city average. For the 2001-2002 period, we escalated this by the trend in the Handy Whitman Index for the Northeast U.S. The value for the 2003 test year is the product of the value for 2002 thus calculated and the average annual growth rate of the Enbridge index thus calculated from 1999-2002.

The full formula for the capital service price index used in the econometric and MFP indexing work was:

$$WKS_{j,t} = d \cdot WKA_{j,j,t} + WKA_{j,t-1}\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}} \right]. \qquad [18]$$

The first term in this expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

Here r_t is the opportunity cost of plant ownership per dollar of plant value. As a proxy for this we calculated for, U.S. companies, the user cost of capital for the U.S. economy using data in the National Income and Product Accounts (NIPA).[11] This variable reflects returns on equity as well as bond yields. The NIPA accounts are published by the BEA in its *Survey of Current Business* series. The user cost of capital was computed analogously for the Canadian economy using Statistics Canada macroeconomic data.

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

A.2.4 Business Condition Variables

Input Price and Output Quantity Variables As noted above, economic theory suggests that the prices of production inputs and the quantities of work performed by utilities should be included in our cost model as business condition variables. The input price variables we employed were the price indexes discussed above in Appendix Section 1.3. There are two output quantity variables in our model: the number of retail customers and total throughput. We expect total cost to be higher the higher are the values of each of these workload measures.

Other Business Condition Variables Four additional business condition variables are included in the cost model. One is the percentage of distribution main not made of cast iron or unprotected bare steel. 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 still heavily used in older North American distribution systems, which tend to be eastern. Greater use of cast iron typically involves a combination of higher maintenance and replacement costs. A higher value for this variable means that a company has less cast iron and unprotected bare steel in its system.

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

The third additional business condition variable in this model is an index of maximum frost depth. Distributors typically dig trenches for their mains deeper the deeper is the maximum frost depth. Maximum frost depth can also raise the cost of maintenance. Frost depth thus raises distribution cost. Our index has a higher value the less is the maximum frost depth.

The fourth and final extra business condition variable in the model is a measure of earthquake risk. The cost of system operation is apt to be greater the greater is the risk. Earthquake risk is greater the greater is the value of this variable.

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

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