New Zealand Gas Distribution Cost Performance:

Results from International Benchmarking

Pacific Economics Group
Economic and Litigation Consulting

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

An appraisal of a utility's cost performance is always challenging given the scope and complexity of conditions that it cannot control. In any industry, there are important differences between firms in the prices at which production inputs can be obtained, the character of local demand conditions, and in the service territory served and other business conditions. Appraisals of gas distribution performance are facilitated by the abundant data that are available in the US.

This study evaluated the cost performance of two New Zealand gas distribution businesses (NZ gas DBs) relative to US gas distributors. The two NZ gas DBs were Vector and NGC. We developed a cost model that explains the effect on a company's gas distribution cost of some measurable business conditions. The parameters of the model were estimated by established statistical methods using recent data from a large sample of investor-owned American gas distribution utilities. The model was used to predict the NZ gas DBs' recent cost given the values for business conditions that each DB faced. Cost performance was evaluated by comparing each DB's actual costs with those predicted by the model.

This general approach to cost performance measurement has some important advantages over alternative benchmarking methods. One is that its effectiveness does not require a suitable peer group. The benchmark is based, instead, on the exact business conditions that a company faces. Another major advantage is the ability to use results of the estimation procedure to create confidence intervals. These reflect the precision of model predictions and therefore help us assess whether differences from point predictions are statistically significant. Approaches based solely on point predictions can create a false sense of precision.

Cost model parameters were estimated using 1997-2002 data for 40 US gas distribution utilities. The major determinants of cost were found to be the amount of work performed by the company, the prices it pays for capital services, labor, and other production inputs, the total miles of distribution main, and the percentage of distribution main that is not cast iron. The parameter estimates were in general statistically significant and plausible in sign and magnitude.

The econometric cost model was used to predict the NZ gas DBs' costs over the 1997-2002 period, given the business conditions that each DB faced. For the 1997-2002 period, NGC's total cost using the ACAM cost measure was 30.3% below its predicted value. This difference was statistically significant, so we conclude that NGC is a superior cost performer. For the 2000-2002 period, Vector's total cost using the ACAM cost measure was 21.4% below its predicted value. This difference was statistically significant, so we conclude that Vector is a significantly superior cost performer.

PEG evaluated the sensitivity of these results to assumptions regarding the opportunity cost of capital, construction cost differentials and exchange rates. We found that our conclusions were not affected by alternative assumptions regarding the opportunity cost of capital or construction cost differentials. If PEG employed New Zealand's 10-year average exchange rate rather than purchasing power parity exchange rates, the actual cost computed for each DB would have been lower in US dollar terms, which would have increased the difference (in absolute value terms) between each company's actual and predicted costs. The alternative exchange rate measure employed in other Commission decisions would therefore have led to greater measured efficiency levels for each NZ gas DB than the exchange rate assumption used by PEG.

1. INTRODUCTION AND SUMMARY

Performance assessment has played an important role in the Commerce Commission's Inquiry into New Zealand's natural gas transmission and distribution sectors. The importance of benchmarking in this proceeding is perhaps most evident in a benchmarking study undertaken on behalf of the Commission by Meyrick and Associates. Meyrick indicates that its study is designed to help the Commission determine whether price control is warranted for NZ's gas businesses. In particular, the Meyrick report states "…if the New Zealand businesses were consistently less cost efficient than the normalized performance of overseas businesses then this would lend support to the case for imposing control."[1]

As part of the Commission's inquiry, two New Zealand gas distribution businesses (DBs) asked Pacific Economics Group LLC (PEG) to evaluate their overall cost performance relative to comparable US utilities. Separate benchmarking studies were to be prepared for NGC and Vector. This report summarizes our findings for both companies.

Our research approach can be briefly summarized. Econometric cost functions were estimated with data from US gas distributors. This yielded estimates of the underlying "drivers" of gas distribution costs. For a given set of operating conditions facing a DB, these estimates were used to generate predictions for the total costs of providing gas distribution services. These predictions were, in turn, used to evaluate a particular DB's performance by comparing the company's actual to its expected cost.

We believe our work has several implications for the current Inquiry. First, it provides valuable information on the NZ gas DBs' cost performance relative to an objective, international standard. The cost model also provides objective, quantitative measures of the impacts of different operating conditions on a DB's costs. New Zealand's

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[1] Meyrick and Associates, *Comparative Benchmarking of Gas Networks in Australia and New Zealand*, Report prepared for Commerce Commission, Wellington, May 14, 2004, p.ii.

gas DBs face differences in their operating environments. Performance benchmarks must be able to "normalize" for operating conditions that are beyond management control. This work represents an important step towards quantifying the impact of these business conditions.

PEG's work also provides information on other issues that have been raised in the Inquiry. For example, the Meyrick report says "extension of the (benchmarking) database to include US utilities would greatly increase the number of observations available and provide more confidence that best practice was being captured although operating environment differences would then be more important. It would also increase the scope to use multiple techniques, including econometric methods. Provided the data supported the necessary estimation, it may then be possible to incorporate more operating environment differences."[2] PEG's work is expressly designed to expand datasets to include US utilities, to employ econometric benchmarking methods that have not yet been used in the Inquiry, and to control for more operating environment differences than previous benchmarking studies. As the Meyrick report suggests, these data and methodological enhancements should lead to more robust evaluations of the NZ gas DBs' cost performance.

For the 1997-2002 period, NGC's total cost using the ACAM cost measure was 30.3% below its predicted value. This difference was statistically significant, so we conclude that NGC is a superior cost performer. For the 2000-2002 period, Vector's total cost using the ACAM cost measure was 21.4% below its predicted value. This difference was statistically significant, so we conclude that Vector is a significantly superior cost performer.

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[2] Op cit, p. iv.

rates, the actual cost computed for each DB would have been lower in US dollar terms, which would have increased the difference (in absolute value terms) between each company's actual and predicted costs. The alternative exchange rate measure employed in other Commission decisions would therefore have led to greater measured efficiency levels for both NZ gas DBs than the exchange rate assumption used by PEG.

The remainder of our report is structured as follows. Chapter Two explains our econometric research on US gas distributors. This chapter includes discussions of our US gas distribution database, econometric methods, and econometric results. Chapter Three applies our econometric gas distribution cost models to the NZ gas DBs and generates benchmarking evaluations of each DB's cost performance given the business conditions that it faced.

2. ECONOMETRIC RESEARCH

2.1. An Overview of the Method

This section provides a substantially non-technical account of the econometric approach to benchmarking employed in this study. 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 influence 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 a company, *i*, in service provision is the product of the minimum achievable cost (C_i^*) and an efficiency factor (*efficiency*$_i$).

$$C_i = C_i^* \cdot efficiency_i . \qquad [1]$$

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 and labor services and other inputs to its production process. 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 as input prices and the amount of work performed increase.

Here is a simple example of a minimum total cost function for gas distribution that is consistent with cost theory.

$$\ln C_{i,t}^* = a_0 + a_1 \cdot \ln N_{i,t} + a_2 \cdot \ln W_{i,t} + u_{i,t} \qquad [2]$$

Here for each firm *i*, in year *t*, the term $C_{i,t}^*$ is the minimal total cost of service. 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 wage rate that the company pays. The wage rate and delivery volume are the measured business conditions in this cost function. The term ln indicates the natural logarithm of a variable.

Combining the results of Equations [1] and [2] we obtain the following model of cost:[3]

$$\ln C_{i,t} = \alpha_0 + \alpha_i \ln N_{i,t} + \alpha_2 \ln W_{i,t} + e_{i,t}. \qquad [3]$$

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 a_0 from Equation [2]. 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 called the error term. We assume that it is a random variable. The error term includes a term $u_{i,t}$ from the minimum total cost function. This term reflects errors in the model specification, including problems in measuring output and other business condition variables. The error term also reflects the difference between the company's efficiency factor and that of 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 using historical data on the costs incurred by utilities and the business conditions that they faced. For example, a positive estimate for α_2 would imply that the costs of sampled companies typically increased when higher wages were paid to employees.

A cost function fitted with econometric parameter estimates may be called an econometric cost benchmark model. We can use such a model to predict a company's

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

$$\begin{aligned}
\ln C_{i,t} &= \ln\left(C^*_{i,t} \cdot efficiency_i\right) \\
&= \ln C^*_{i,t} + \ln efficiency_i \\
&= \left(a_0 + a_1 \ln N_{i,t} + a_2 \ln W_{i,t} + u_{i,t}\right) + efficiency_i \\
&= \left(a_0 + efficiency^{average}\right) + a_1 \ln N_{i,t} + a_z \ln W_{i,t} \\
&\quad + \left[u_i + \left(efficiency_i - efficiency^{average}\right)\right] \\
&= \alpha_0 + \alpha_i \ln N_{i,t} + \alpha_2 \ln W_{i,t} + e_{i,t}
\end{aligned}$$

cost given values for the business conditions that the company faced. Returning to our simple example, we might predict the (logged) cost of NGC in period *t* as follows:[4]

$$\ln \hat{C}_{NGC,t} = \hat{\alpha}_0 + \hat{\alpha}_1 \cdot \ln N_{NGC,t} + \hat{\alpha}_2 \cdot \ln W_{NGC,t} . \qquad [4]$$

Here $\hat{C}_{NGC,t}$ denotes the predicted cost of NGC in period *t*, $N_{NGC,t}$ is the number of customers it served, and $W_{NGC,t}$ is the wage rate that it paid. The $\hat{\alpha}_0$, $\hat{\alpha}_1$, and $\hat{\alpha}_2$ terms are parameter estimates. Notice that in this model the cost benchmark reflects, through the estimated parameter α_0, the *average* efficiency of the sampled utilities. If the expected value of $u_{i,t}$ is zero, it can be shown that the percentage difference between NGC's actual cost and that predicted by the model is equal to the percentage difference between NGC's efficiency factor and that of the sample mean firm.

$$\ln\left(C_{NGC,t} \big/ \hat{C}_{NGC,t} \right) = \ln\left(efficiency_{NGC} \big/ efficiency^{average} \right) \qquad [5]$$

This percentage difference is therefore a measure of the company's cost performance.

A well-specified cost benchmarking model can generate the best estimate of a company's cost given the business conditions that it faces. This is an example of a <u>point prediction</u>. An important advantage of econometric benchmarking is that it provides information about the *precision* of such point predictions. According to econometric theory, precision improves as the variance of the model's prediction error declines. The variance of the prediction error can be estimated using a well-established formula. This formula shows that the precision of cost model predictions will increase as:

1) The size of the sample increases.
2) The number of business condition variables in the model declines.
3) The business conditions of sample companies become more heterogeneous.
4) The business conditions of the company in question become closer to those of the typical firm in the sample.

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

5) The model is more successful in predicting the costs of the sampled companies.

The estimated variance of the prediction error can be used in two ways to assess the model's precision. One is to calculate a t-statistic for the point prediction. This statistic will decline as the estimated variance increases.

A second approach is to construct a confidence interval around the point prediction. The point prediction lies at the center of this interval. The confidence interval may be viewed as the full range of cost predictions that is consistent with the sample data at a given confidence level. It is wider as the estimated variance of the prediction error increases.

We can use t-statistics or confidence intervals to assess the statistical significance of differences between a company's actual and predicted costs. For example, if a distributor's actual cost is not within a confidence interval, we may conclude that its actual cost differs significantly from the model's prediction. If its cost is significantly *below* the model's prediction, for instance, we may deem the company a *superior* cost performer.

The econometric approach to cost benchmarking has several important advantages over alternative benchmarking methods. First, econometric techniques allow us to control for a range of important business conditions that affect utility cost. This makes it possible to do effective benchmarking with data from distributors facing different business conditions. Relatedly, the benchmark does not require the identification of a suitable peer group but is instead based on the exact business conditions that were faced by a DB. This is important in the present context since, *inter alia*, the lack of data from New Zealand and/or Australian gas distributors makes the selection of an appropriate peer group a difficult and controversial exercise.

At the same time, this approach makes good use of data from utilities operating under a wide array of business conditions. Variation in sampled business conditions is actually welcomed in econometric benchmarking since it helps to make estimates of model parameters more accurate. Suppose, for example, we want an accurate estimate of

a_2, which determines the effect of wage rates on cost. It is then desirable for the sample to include a large number of companies facing a wide range of wage rates. The numerous US gas distributors for which quality data are available confront widely varied business conditions, including differences in local labor markets, customer demands, and the degree of urbanization. This disparity in operating environments suggests that econometric estimates based on US data are more likely to provide accurate estimates of the underlying drivers of gas distribution cost than those derived from more homogeneous samples.

Another important advantage is the focus on total cost as the performance indicator. This makes it possible to use the economic theory of cost to select business condition variables. The resultant benchmarking model is then free of the accusation of being a "black box".

The availability of confidence intervals is another important advantage. Approaches based solely on point predictions create a false sense of precision. In fact, we should be surprised if available data permit us to identify many superior or inferior performers with confidence.

2.2. Data

The primary source of the data used in our gas distribution cost research changed over the full sample period used in our work. The *Uniform Statistical Report* (USR) was the primary data 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. Others do not file complete USRs. Some companies 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 of interstate gas transmission companies to the Federal Energy Regulatory Commission (FERC). Other sources of data were also used in the indexing research. These included Global Insight (formerly DRI/McGraw Hill); Whitman, Requardt & Associates; 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 the Energy Information Agency ("EIA") of the U.D. Department of Energy.

Our final sample includes quality data for 40 gas distributors gathered over the 1997-2002 period. The sample includes most of the larger gas distributors in the US. The sampled distributors are listed by region in Table 1.

2.3. Definition of Gas Distribution Cost

The measure of gas distribution cost for the cost model was designed to be comparable with the gas distribution services defined by the Commerce Commission for the Inquiry. It includes gas distribution itself and metering assets (where owned by the distributor) but does not include meter reading, billing, collection, call center, and other retailing-related activities. PEG's US benchmarking work typically allocates these retail-related costs to gas distribution. To ensure comparability, we eliminated all costs classified as customer accounts expenses and customer service and information (CSI) expenses from our measure of US O&M distribution costs.

Total gas distribution cost was the sum of this modified O&M cost measure, a share of Administrative and General (A&G) expenses, and assigned capital cost. Capital costs were computed using net plant values in a base year and the value of plant additions in subsequent years. Details of the computation of capital cost are discussed in Section 2.3.2

2.3.1. Assignment of Administrative and General Costs

A&G expenses consist mainly of pensions and other benefits for all employees, of the salaries of personnel not assigned to line positions, and expenses for office supplies, outside services, and injuries and damages. General plant consists mainly of structures and improvements not allocated to specific functions, communications equipment, office furniture and equipment, and transportation equipment. The portion of these costs

Table 1

SAMPLE GAS DISTRIBUTORS FOR BENCHMARKING

Region	Company	Number of Customers (2002)
Northeast		
	Boston Gas	553,551
	Central Hudson Gas & Electric	66,757
	Connecticut Natural Gas	148,133
	Consolidated Edison	1,051,776
	Keyspan Energy Delivery	1,245,106
	New Jersey Natural Gas	437,311
	Niagara Mohawk	551,436
	Nstar	248,736
	Orange & Rockland Utilities	121,182
	PECO	449,108
	People's Natural Gas	354,358
	PG Energy	157,465
	Public Service Electric & Gas	1,665,668
	Rochester Gas & Electric	289,860
	Southern Connecticut Gas Co.	169,319
South Atlantic		
	Atlanta Gas Light	1,519,499
	Baltimore Gas & Electric	609,349
	Public Service Company of North Carolina	367,177
North Central		
	Consumers Power	1,652,309
	East Ohio Gas	1,213,805
	Illinois Power Co	399,499
	Madison G & E	124,416
	North Shore Gas	151,548
	Northern Illinois Gas	2,023,255
	People's Gas Light & Coke	837,212
	Wisconsin Gas	556,768
	Wisconsin Power & Light	165,567
South Central		
	Alabama Gas Corp (Alagasco)	461,232
	Louisville Gas & Electric	308,344
	Oklahoma Natural Gas	778,820
Southwest		
	Enserch	1,450,879
	Questar	735,847
	Southwest Gas	1,406,648
Northwest		
	Cascade Natural Gas	204,735
	Northwest Natural Gas Co	549,213
	Puget Sound Energy, Inc.	613,540
	Washington Gas Light Co.	941,456
California		
	Pacific Gas & Electric	3,940,442
	San Diego Gas & Electric	782,530
	Southern California Gas	5,143,877

Total for Sample	34,447,733
Industry Total *	66,410,361
Percentage of U.S. Total	51.9%
Number of Sampled Firms	40

*Source For US Total: U.S. Energy Information Administration, *Natural Gas Annual 2002* assigned to gas distribution was equal to its share of non-A&G salaries and wages. The salary and wage data were drawn from FERC Form 2.

2.3.2. Capital Cost

Our measure of capital cost in this report was chosen to satisfy two goals. First, we wanted the approach to have a solid base in economic theory and the scholarly literature. This has been the main criterion used to measure capital cost in our previous benchmarking work.

We also wanted to measure capital cost consistently for the U. S. and New Zealand utilities. This reflects our general desire to make the distribution cost measures as comparable as possible across the two countries. Because the methods used to measure DB capital were an important factor in calculating U. S. capital costs, it is valuable to review these techniques briefly.

The capital stock values for NZ's gas DBs were based on the "optimized deprival value" (ODV) for gas distribution capital. Each DB's ODV capital stocks are updated to include the effects of inflation, depreciation, and capital additions and disposals since the time of the valuation. Depreciation is calculated using the straight line method. In some instances, capital values are "optimized" to eliminate assets that are considered to be redundant or otherwise uneconomic.

It was not possible to replicate the same process for the US gas distributors, but our capital cost measure incorporates the main assumption that underpin the computations of New Zealand capital cost. Most importantly, our valuations of U. S. capital stocks in each year reflect the effects of inflation and straight line depreciation. Depreciation by a straight line accounting method was a departure from our past depreciation measures, which reflect geometric rather than straight line rates of decay. We changed our depreciation measures to be consistent with the New Zealand treatment. The annual depreciation rates that apply to any given U. S. utility in our sample also reflect an assigned pattern of straight line depreciation. The details of our depreciation measure are presented in the Appendix.

In general, our study utilized a service price approach to capital cost measurement that is based on the economic value of utility plant. This approach has a solid basis in economic theory and the scholarly literature.[5] It controls in a precise and standardized fashion for differences between utilities in the age of plant additions. Accordingly, there is no need for a "plant age" business condition variable.

The service price approach to capital cost measurement has ample precedent in cost research. It is used by the BLS of the US Department of Labor in computing multi-factor productivity indexes for the US private business sector and for several subsectors, including the utility services industry. The cost of capital in a given year, *t*, can be expressed as the product of a capital service price index and a capital quantity index. The formula may be stated formally as:

$$CK_t = WKS_t \cdot XK_{t-1} \qquad [6]$$

where in each period *t*, CK_t is the cost of a capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period. The capital quantity index is constructed using inflation-adjusted data on the value of net utility plant in a benchmark year and of gross plant additions in subsequent years. The service price index is based on the cost of providing capital services in a competitive rental market. Both indexes require a mathematical characterization of the process of plant depreciation.

Non tax capital cost is the product of the capital quantity index and WKS_t^{other} where:

$$WKS_t^{other} = r_t \cdot WKA_{t-1} + d_t \cdot WKA_t - \left(WKA_t - WKA_{t-1}\right). \qquad [7]$$

The three terms in this formula correspond to the three components on non-tax capital cost. These are, in order, the opportunity cost of capital, depreciation, and capital gains. The user cost of capital and capital gains are smoothed using a three-year moving average.

Here, r_t is the user cost of capital for the US economy.[6] This is the return to capital implicit in the National Income and Product Accounts (NIPA) produced by the

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[5] See Hall and Jorgensen (1967) for a seminal discussion on the use of service price methods for measuring capital cost.

Department of Commerce. The user cost of capital for the US economy is both a broader and simpler measure of the opportunity cost of capital than the weighted average cost of capital (WACC) that is often computed in regulatory proceedings. It is broader because it reflects economy-wide rather than industry-specific returns; it is simpler since it is computed directly from NIPA accounts and does not, for example, require the calculation of risk-free interest rates or industry risk premiums. The economy-wide user cost of capital also has ample precedent in regulatory benchmarking and productivity studies, including PEG's previous work in the US, Canada, Australia and other countries.

To complete the calculation of the capital service price, it is necessary to determine the relative levels of utility plant asset prices at one point in time. We perform this exercise for 1999. The basis for the levelization was the City Cost Indexes in Mean's Heavy Construction Cost Data.[7] These measure, as is appropriate, differences between cities in the cost of labor needed to install gas equipment as well as differences

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[6] The US economy user cost of capital is not directly observable, but it can be measured by applying two economic relationships. The first economic pertains to the National Income and Products Accounts (NIPA) definitions of Gross Domestic Product (GDP) and the cost of inputs used by the US economy. In the NIA, the total cost of the US economy inputs is equal to GDP. At the economy-wide level there are two inputs: labor and capital. Therefore, the total cost of capital is equal to GDP less Labor Compensation (CL), or:

$$CK = GDP - CL$$

$$CK = P_k \cdot K \qquad (2)$$

where P_k represents the price and K the quantity of capital input. The price of capital can be decomposed into the price index for new plant and equipment (J), the opportunity cost of capital (r), the rate of depreciation (d), the inflation rate for new plant and equipment (l), and the rate of taxation on capital (t):

$$P_k = J \cdot (r + d - l + t) \qquad (3)$$

Combining (2) and (3) one obtains the relationship:

$$\begin{aligned} CK &= J \cdot (r + d - l + t) \cdot K \\ &= r \cdot J \cdot K + d \cdot J \cdot K - l \cdot J \cdot K + t \cdot J \cdot K \qquad (4) \\ &= r \cdot VK + D - l \cdot VK + T \end{aligned}$$

where CK represents the total cost of capital. The second relationship is between the total cost of capital and the components of the capital price equation. The total cost of capital is equal to the product of the quantity of capital input and the price of capital input., or:

where D represents the total cost of depreciation, T total indirect business taxes and corporate profits taxes, and VK the current cost of plant and equipment net stock. Combining (1) and (4), one can derive the following equation for the opportunity cost of capital:

$$r = {(GDP - CL - D - T + l \cdot VK)}\big/{(VK)} \qquad (5)$$

in equipment prices. The level of the asset price index for each utility was the simple average of the Means index values for cities in the service territory.

2.4 Business Condition Variables

2.4.1 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 two output quantity variables in our model: the number of retail customers, and the total volumes of gas delivered to retail customers. We expect cost to be higher as the quantity of each of these outputs increases.

2.4.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, we have specified input price variables for capital, labor, and other O&M inputs.[8] We expect cost to be higher as the values of these price variables increase.

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 US as a whole. Values for 1997 and 1999-2002 were calculated by adjusting the 1998 level for changes in the Employment Cost Index for the EGS sector over the 1997-99 period.

GDP, labor compensation, depreciation, and taxes are reported annually in the NIPA. The current cost of plant and equipment net stock and the inflation rate for plant and equipment are not reported in the NIPA, but are reported in Fixed Reproducible Tangible Wealth in the United States.

[8] R.S. Means, *Heavy Construction Cost Data, 11th Annual Edition*, (Kingston, MA: RS Means Company, Inc.)

[8] The materials price does not appear in the estimated parameter tables due to the imposition of the linear homogeneity restriction predicted by economic theory.

Prices for other O&M inputs are assumed to be the same in a given year for all companies. They are escalated by the growth in GDP-I. Our general approach to the computation of a price index for capital services is described in Section 2.3.2.

2.4.3 Other Business Conditions

Two additional business condition variables are included in the cost model. One is the total miles of distribution main. This reflects the extent of a company's gas distribution network which in turn, is driven largely by the spatial distribution of its customers. All else equal, for two distributors serving an equal number of customers, the one with more miles of distribution main would have lower customer density in its service territory. We expect the parameter for this variable to have a positive sign, indicating that costs are expected to rise as the miles of distribution main increase (equivalently, as customer density *decreases*).

Another business condition is the percentage of distribution main not made of cast iron. Cast iron pipes were frequently used in gas system construction in the early days of the industry. They are more common in older distribution systems, which tend to be located in the eastern US. Greater use of cast iron pipe typically raises both maintenance and replacement costs. A higher value for this variable means that a company owns relatively less cast iron main. Hence, we would expect the parameter for this variable to be negative.

2.5 Estimation Procedure

2.5.1 Form of the Cost Model

A translog form was selected for the cost model. This form has been widely used in scholarly cost function research. We have also used this form in our previous benchmarking work for energy utilities. A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can, in principle, reflect.[9]

Here is the translog form corresponding to the simple cost model first presented in Section 2.1 (recall that values for all of these variables are logged).

$$C_{i,t} = a_o + a_1 \cdot V_{i,t} + a_{11} \cdot V_{i,t}^2 + a_2 \cdot W_{i,t} + a_{22} \cdot W_{i,t}^2 + a_{12} \cdot V_{i,t} \cdot W_{i,t} + u_{i,t} \qquad [8]$$

It can be seen to have three additional terms. Two are squared terms for the measured business conditions in the model. They allow the elasticity of cost with respect to the variable to rise or fall with the value of the variable. For example, the elasticity of cost with respect to the price of labor might be higher at very high labor prices due to labor/capital substitutions. The third new variable is the interaction term, $V_{i,t} \cdot W_{i,t}$. It allows the cost impact of one variable to depend on the value of the other variable. For example, the effect of the delivery volume on cost might depend on the price of labor.

The assumption of a well-behaved production technology permits us to impose some restrictions on model parameters that can reduce the number of parameters requiring estimation. The restrictions include linear homogeneity in input prices and symmetry in the parameters of the price interaction terms. These assumptions are commonly made in cost function research.

2.5.2 Joint Estimation

A fundamental result of cost theory called Shepherd's lemma permits us to derive

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[9] The general form of the translog cost function is:

$$\begin{aligned}
\ln C = {} & \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_h \alpha_h \ln Z_h + \sum_j \alpha_j \ln W_j + \alpha_t T \\
+ {} & \frac{1}{2}\left[\sum_i \sum_k \gamma_{ik} \ln Y_i \ln Y_k + \sum_h \sum_m \gamma_{hm} \ln Z_h \ln Z_m + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n + \gamma_{tt} T^2\right] \\
+ {} & \sum_i \sum_h \gamma_{ih} \ln Y_i \ln Z_h + \sum_h \sum_j \gamma_{hj} \ln Z_h \ln \; W_j \\
+ {} & \sum_i \sum_j \gamma_{ij} \ln Y_i \ln Z_j + \sum_i \gamma_{it} \ln Y_i \; T \\
+ {} & \sum_j \gamma_{jt} \ln W_j T + \sum_h \gamma_{ht} \ln Z_h \; T.
\end{aligned}$$

Table 2

ECONOMETRIC COST MODEL FOR GAS DISTRIBUTION

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number Customers
V = Total Throughput
NI = % of Main that is Non-cast Iron
M = Miles of Distribution Main

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC
L	0.227	57.78	N	0.617	20.64
LL	-0.401	-7.33	NN	0.141	1.57
LK	-0.001	-0.06	NV	-0.060	-0.74
LN	0.001	0.06			
LV	0.058	5.95	V	0.071	3.03
LNI	-0.204	-7.47	VV	-0.085	-1.17
LM	-0.048	-3.79			
			NI	-0.661	-8.93
K	0.680	258.82			
KK	0.058	3.05	M	0.192	7.20
KN	0.017	2.03			
KV	0.028	5.10			
KNI	0.121	4.74	Constant	12.791	899.76
KM	-0.051	-5.39			
			Trend	-0.011	-3.34
			System Rbar-Squared	0.972	

cost share equations that are consistent with a cost function of translog form.[10] These equations are customarily estimated jointly with the cost function. Cost share equation parameter estimates can be examined for consistency with economic theory.

2.5.3 Estimation Procedure

The appropriate method for estimating model parameters depends on our assumptions regarding the distribution of the error term. Following a classic econometric paper by Mundlak, we assume that the error term is the sum of a firm specific effect, d_i, that is constant over the sample period and a random variable $e_{i,t}$ with a mean of zero whose value may vary from year to year.[11]

$$u_{i,t} = d_i + e_{i,t} \qquad [9]$$

A firm specific effect captures any persistent deviation in the cost of a company from that predicted by the business condition variables over the sample period. It reflects the net effect of a range of conditions, including differences in the efficiency of companies and in business conditions that were excluded from the model.

We assume, following Mundlak, that the firm specific effect has a systematic and a non-systematic component. The systematic component depends on the mean values of the included business condition variables. For example, the impact on the cost of an excluded output quantity variable might very well be larger as the value of the included output quantity variables increase. Only the non-systematic effect is assumed in our study to reflect the cost inefficiency of the utility. Applying this formulation, the parameters of the cost function and two cost share equations are then estimated simultaneously using an iterative Zellner procedure that has attractive statistical properties.

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[10] The general form of the equation for a representative input price category, *j*, is:

$$S_j = \alpha_j + \sum_i \gamma_{ij} \ln Y_i + \sum_n \gamma_{jn} \ln W_n$$

[11] Yair Mundlak, "On the Pooling of Time Series and Cross Section Data" *Econometrica*, Vol. 46, pp. 69-85, 1978.

2.6. Empirical Results

Estimates of the parameters of the distribution cost model are reported in Table 2. Because mean-scaled data are used in the estimation process, the parameter values are elasticities for the sample mean firm. Each can be interpreted as the percentage change in cost caused by a 1% increase in the value of the corresponding variable.

Results are shaded for the first order terms. There are the terms that do not involve squared values of business condition variables or interactions between two variables. Results for these terms are of special interest since they represent the overall elasticities for the basic business condition variables for the sample mean firm.

Table 2 also reports the values of the corresponding asymptotic *t* ratios. Any individual parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test depends on the critical value of the asymptotic t ratio. In this study, we employed critical values that are appropriate for a 95% confidence level. The critical value was 1.96.

Inspecting the results for the first order terms in Table 2, we find that they are in general quite plausible. The estimated elasticities of cost with respect to input prices for the sample mean firm are positively signed, as expected, and are highly significant statistically. The estimates reveal that distribution cost was much more sensitive to a change in the price of capital than to changes in the prices of labor or other inputs.[12] This makes sense since capital services accounted for a much larger share of applicable total cost.

The estimated sample mean elasticities of cost with respect to delivery volumes and number of customers are both positive (0.071 and 0.62, respectively) and statistically significant. The positive signs mean that cost rises with growth in the amount of work performed. The larger value on customer numbers means that gas distribution cost is more sensitive to customer growth than to volume growth.

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[12] Since we employ mean-scaled data in our estimation, the estimated price parameters are equal to the cost elasticities and estimated cost share of the sample mean firm.

The coefficients on the business condition variables are also reasonable and statistically significant. The coefficient on total miles of distribution main is positive, as expected. This indicates that reported costs increase as the extent of the delivery network increases or, alternatively, as customer density decreases. The coefficient on the percentage of distribution main that is not cast iron is negative. This shows that costs decline as distributors have fewer cast iron pipes, as expected.

3. APPLICATION TO NEW ZEALAND GAS DISTRIBUTORS

3.1 General Procedures

The parameter estimates presented in the previous chapter were used to evaluate the NZ gas DBs' costs through the following procedure. First, relevant data on each DB's independent variables were substituted into the econometric total cost model. That is, given values for each DB's customer numbers; delivery volumes; prices for capital, labor and other O&M inputs; total miles of distribution main; and the share of distribution lines that were not cast iron; the econometric model was used to generate a "point" prediction for that DB's gas distribution costs and an associated confidence interval. Each DB's comprehensive performance was evaluated by comparing its total costs of gas distribution services to this prediction and confidence interval.

To undertake such cost comparisons, it is important for the variables to be defined as similarly as possible across countries. Below we detail the steps that were taken to insure that the elements that went into the evaluation of NZ gas DB costs were analogous to those used in estimating the econometric cost model.

3.2 Outputs

Retail customer numbers and delivery volumes are defined analogously in the US and New Zealand.

3.3 Input Prices

We defined input prices to be analogous to those used in the US. For both the NZ gas DBs and each US utility, the labor price was external to the company. The labor price in NZ Gas DBs was equal to the annualized earnings of workers in New Zealand's electricity, gas and water supply sector, as available from Statistics New Zealand. The materials price index for NZ gas DBs' was linked to the US GDP-PI, which was used to measure materials prices for US utilities. We established the initial linkage by using data from Mercer, Inc. on comparative cost of living levels in the US and New Zealand.

Capital service prices were computed using data on the opportunity cost of capital in New Zealand, the cost of construction in Melbourne relative to the US, and a constant 4.5% depreciation rate vote for each NZ gas DB. The assumption of a 4.5% depreciation rate is consistent with the assumption used in the Meyrick report.

The user cost of capital for New Zealand was calculated in the same way as that described for the US. National income account and aggregate capital stock data needed for this calculation were obtained from the Stats New Zealand.

An estimate of the NZ gas DBs' construction costs was derived from the *Richardson International Construction Factors: Location Cost Manual.* This manual contains estimates of US dollar estimates of construction costs in Australia relative to the US average construction cost although it does not provide similar information for New Zealand. We used the Australian data as the best available proxy of New Zealand construction costs since the relevant data were not readily available for New Zealand. We used the Richardson estimates in their 1999 volumes as the starting point for estimating the relative cost of construction in New Zealand at the end of 1999. We then examined the inputs and assumptions that Richardson used to derive these estimates. After discussing these details with Richardson personnel, we made three adjustments that were designed to reflect recent circumstance more accurately. These changes were an updating of the import duties to reflect recent tariff changes; an upward adjustment in the Richardson assessment of the productivity of Australian labor relative to the US; and the use of purchasing power parity (explained below) rather than current exchange rates to translate Australian wage rates into US dollar equivalents. After making these adjustments, it was estimated that relative construction costs in Melbourne were 31% above the US average in 1999. In Section 3.8 we examine the sensitivity of our benchmarking results to this assumption.

3.4 Exchange Rates

The NZ Gas DBs's total cost was converted into a US dollar equivalent by using a purchasing power parity (PPP) exchange rate. This value is calculated by the Organization for Economic Cooperation and Development (OECD) and is used by the OECD when making comparisons of output values across OECD countries. PEG believes that PPP exchange rates are better measures of the "real" underlying differences between values in the two countries than the current exchange rates that may apply at any point in time.[13] In recent years, the PPP exchange rate has been very near 1.45 NZ$ for each US$.

The PPP exchange rate differs from the exchange rate assumption the Commission used in its *Comparative Review of Interconnection Pricing*. In that proceeding, the Commission used the 10-year average exchange rate to make international benchmarking comparisons. For the US-NZ exchange rate, this 10-year average was 0.5577 US$ to every 1NZ$. This compares with a PPP rate of 1/1.45 = 0.69. Our benchmarking model generates cost predictions in US dollars, which are then compared to the actual costs of the NZ gas DBs as expressed in US dollars. If we employed the 10-year average exchange rate used by the Commission for this conversion, the actual costs of the NZ gas DBs would be about 20% lower than the costs that PEG actually computed (*i.e.* .5577/.69 = .808). All else equal, PEG's exchange rate assumption therefore leads to less measured efficiency (the difference between actual and predicted costs) than would the alternative measure previously used by the Commission.

3.5 Other Business Condition Variables

Each NZ gas DB provided estimates of its total miles of distribution main and the share of distribution pipe in total miles of pipe.

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[13] The source of the purchasing power exchange rate was *OECD: Main Economic Indicators*

3.6 Values for NZ Gas DBs

Table 3 compares the average values of utility cost and business condition variables for both NZ gas DB and the corresponding values for the sample mean US utility. One notable fact from this table is that the NZ gas DBs are quite small relative to the US average. It can be seen that the costs of NGC and Vector are only 5% and 8%, respectively, that of the average US firm. NGC and Vector also serve about 6% and 8%, respectively, as many customers as a typical US firm. Together, these data imply that the average cost per customer for both of the NZ gas DBs is equal to or lower than that of the US average firm. The table also indicates that NGC and Vector distribute only 4% and 5%, respectively, as much volume as the sample average US firm. Consumption per customer is therefore lower for each of the NZ gas DBs than for a typical US gas distributor.

Turning to input prices, it is seen that labor prices are somewhat higher and materials prices somewhat lower for the NZ gas DBs than for US distributors. The NZ gas DBs' capital service prices were 19% above those of an average US utility. This differential is driven by the construction cost differential computed by Richardson. Section 3.8 will present results that test the sensitivity of our results to this assumption.

Since the NZ companies are much smaller than the US distributors, it should not be surprising that they also have fewer miles of distribution main. NGC and Vector have 14% and 26% as much distribution main, respectively, as the average US distributor. But since these companies serve only 6% and 8%, respectively, as many customers as a typical US firm, it follows that each of the NZ gas DBs have fewer customers per mile of pipe, or lower customer density, than the US average. All else equal, lower customer densities will tend to raise predicted costs. Finally, it can be seen that NGC and Vector each have relatively fewer cast iron mains than the average US firm. Since a cast iron intensive system tends to raise cost, all else equal this factor tends to reduce predicted cost for the NZ gas DBs.

Table 3

Average Values of Variables in the Benchmarking Study:
Gas Delivery

Variable	**Units**	**U.S. Sample Average**	**NGC**	**NGC/ Sample Mean**	**Vector**	**Vector/ Sample Mean**
Gas Delivery Cost	1,000 Dollars	342,194	16,762	0.05	27,435	0.08
Number of Customers	Customers	828,413	47,991	0.06	64,303	0.08
Total Throughput	MDt	194,147	8,662	0.04	10,341	0.05
Price of Capital Services	Index Number	13.13	15.64	1.19	16.09	1.23
Price of Labor Services	Index Number	38,616	40,801	1.06	41,553	1.08
Price of Materials	Index Number	0.96	0.88	0.91	0.92	0.96
Miles of Distribution Main	Miles	10,774	1,508	0.14	2,824	0.26
Percent of Main not Cast Iron	Percent	90.68%	100.00%	1.10	93.71%	1.03

3.7 Results

These data and the econometric models were used to evaluate the NZ gas DBs' total cost. Table 4 displays actual and predicted costs for NGC and Vector. The table also presents the t-statistic on the hypothesis that predicted cost is equal to actual cost. Actual and predicted costs are presented for 1997 through 2002 for NGC but only for 2000-2002 for Vector since data before 2000 are not available for this company. The sample end date of 2002 corresponds to the last year for which we currently have the necessary US gas distributor data.

In 1997-2002, NGC's total cost using the ACAM cost measure was 30.3% below its predicted value. This difference was statistically significant, so we conclude that NGC is a superior cost performer. For the 2000-2002 period, Vector's total cost using the ACAM cost measure was 21.4% below its predicted value. This difference was statistically significant, so we conclude that Vector is a significantly superior cost performer.

PEG also constructed 95% confidence intervals around our cost predictions. These confidence intervals can be relevant for examining how alternative cost allocations, and therefore total cost measures, for the NZ gas DBs affect benchmarking evaluations. For example, as long as an alternative cost allocation led a gas DB's total cost to remain less than the lower band of the confidence interval, the hypothesis that actual cost was equal to predicted cost would still be rejected and the company would still be a significantly superior cost performer. Below we present the 95% confidence intervals (all expressed in thousands of US $) for both NZ gas DBs.

	Predicted Cost	Lower Band Confidence Interval	Upper Band Confidence Interval
NGC	$24,049	$23,015	$25,083
Vector	$34,916	$33,467	$36,365

It is important to note that PEG's cost predictions, as well as the confidence intervals above, correspond to *average* costs over the entire sample period (1997 to 2002 for NGC,

Table 4

Actual and Predicted Comprehensive Cost (U.S. $) for Gas Distribution:

NGC 1997-2002

Actual Cost $1,000	Predicted Cost $1000	Difference (%)	t-statistic
16,762	**24,049**	**-30.30%**	**-16.40**

Vector 2000-2002

Actual Cost $1,000	Predicted Cost $1000	Difference (%)	t-statistic
27,435	**34,916**	**-21.42%**	**-7.51**

2000 to 2002 for Vector). Any alternative cost measures computed for each DB would therefore have to be calculated for each of these sample years and the average value computed and expressed in US dollars (at PPP exchange rates) to examine whether cost reallocations affect the benchmarking conclusions.

3.8 Sensitivities

PEG evaluated the sensitivity of these results to assumptions regarding the opportunity cost of capital, construction cost differentials and exchange rates. The implications of using the Commission's previous exchange rate assumption have already been discussed. We also considered three alternative scenarios. One is for the opportunity cost of capital in New Zealand to be 1% higher than what we computed for the NZ economy-wide return to capital. A second is for the opportunity cost of capital in New Zealand to be 1% lower than what we computed for the NZ economy-wide return to capital. A third is that construction costs in the US and New Zealand gas distribution industries are equal.

The results of these alternative benchmarking models are presented in Table 5. For each company, we present actual and predicted cost for each scenario, as well as the "base case" model discussed before. It can be seen that none of our conclusions is qualitatively different under the alternative scenarios. More specifically, NGC's actual cost remains significantly less than predicted cost in all scenarios and Vector's actual cost remains significantly less than predicted cost in all scenarios. We therefore find that our conclusions are not affected by alternative assumptions regarding the opportunity cost of capital or construction cost differentials.

Table 5

Sensitivity Analysis of Econometric Cost Predictions

Actual and Predicted Comprehensive Cost for Gas Distribution:

NGC 1997-2002

	Actual Cost $1,000	Predicted Cost $1000	Difference (%)	t-statistic
Base Case	**16,762**	**24,049**	**-30.3%**	**-16.4**
1% decrease in the opportunity cost of capital	**16,047**	**22,967**	**-30.1%**	**-16.3**
1% increase in the opportunity cost of capital	**17,478**	**25,231**	**-30.7%**	**-16.7**
No differential between NZ and U.S. Construction Costs	**16,762**	**23,221**	**-27.8%**	**-14.9**

Vector 2000-2002

	Actual Cost $1,000	Predicted Cost $1000	Difference (%)	t-statistic
Base Case	**27,435**	**34,916**	**-21.4%**	**-7.5**
1% decrease in the opportunity cost of capital	**26,249**	**33,749**	**-22.2%**	**-7.8**
1% increase in the opportunity cost of capital	**28,621**	**36,414**	**-21.4%**	**-7.5**
No differential between NZ and U.S. Construction Costs	**27,435**	**34,534**	**-20.6%**	**-7.2**

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APPENDIX: DERIVATION OF THE ECONOMIC COST OF CAPITAL AND CAPITAL SERVICE PRICE

This appendix explains the derivation of the economic cost of capital and corresponding capital service price that is used in this study. Terms of the formulas are defined in the following glossary. Two practical approaches to calculating the economic cost of capital are then discussed.

Glossary of Terms

In each year, *t*, we define the following economic variables.

$$\begin{aligned}
CK_t &= \textit{cost of capital} \\
WKA_t &= \textit{capital asset price} \\
xk_t &= \textit{capital asset quantity} \\
a_{t\text{-}s} &= \textit{quantity of capital additions made in year } t\text{ - }s \\
N &= \textit{economic life of plant} \\
r_t &= \textit{interest rate} \\
d &= \textit{depreciation rate}
\end{aligned}$$

Geometric Decay

The best established approach to calculating the economic cost of capital is the geometric decay approach.[14]

$$\begin{aligned}
CK_t^{GD} &= CK_t^{Opportunity} - CK_t^{Capital\ Gains} + CK_t^{Depreciation} \\
&= r_t \cdot WKA_{t-1} \cdot xk_{t-1} - \left(WKA_t - WKA_{t-1}\right) \cdot xk_{t-1} + d \cdot WKA_t - xk_{t-1} \\
&= \left[r_t \cdot WKA_{t-1} + \left(WKA_t - WKA_{t-1}\right) + d \cdot WKA_t\right] \cdot xk_{t-1} \\
&= WKS_t^{GD} \cdot xk_{t-1}
\end{aligned}$$

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[14] For a discussion of the economic cost of capital see Charles R. Hulten and Frank C. Wykoff, "The Measurement of Capital Deprecation" in C. Hulten, editor, *Depreciation, Inflation, and the Taxation of Income from Capital*, Washington, D. C., the Urban Institute (1981).

The capital asset quantity is defined by the following perpetual inventory equation.

$$
\begin{aligned}
xk_{t-1} &= xk_{t-2} - d \cdot xk_{t-2} + a_{t-1} \\
&= (1-d) \cdot xk_{t-2} + a_{t-1}
\end{aligned}
$$

It can be seen that the economic cost of capital has three components. These are the opportunity cost and depreciation cost less capital gains. Capital cost in a given year can be expressed as the product of the size of the capital stock at the end of the preceding year and a capital service price. The capital service price is so called because it may be viewed as the price that would be charged in a competitive rental service market. It is higher the higher is the depreciation rate, interest rate, and asset price and the slower is asset price inflation. The depreciation rate is constant from year to year.

Straight Line Depreciation

An alternative approach to the computation of capital cost is indicated in the present benchmarking application. New Zealand's gas distributors report plant value data on an ODV cost basis that features straight line depreciation. The available data for these companies do not permit us to calculate their capital cost using the geometric decay method. They do, however, permit us to calculate the economic cost of capital for both American and New Zealand distributors using straight line depreciation.

We begin our derivation of the service price equation for the case of straight line depreciation by supposing that the economic cost of capital has the same three components as in the geometric decay case. Now

$$
\begin{aligned}
CK_t^{SL} &= CK_t^{Opportunity} - CK_t^{Capital\ Gains} + CK_t^{Depreciation} \\
&= \sum_{s=1}^{N} \left[r_t \cdot WKA_{t-1} \cdot \frac{N-s+1}{N} \cdot a_{t-s} - \left(WKA_t - WKA_{t-1}\right) \cdot \frac{N-s+1}{N} \cdot a_{t-s} + WKA_t \cdot \frac{1}{N} \cdot a_{t-s} \right]
\end{aligned}
$$

If

$$
\begin{aligned}
xk_{t-1}^{t-s} &= \textit{capital quantity at the end of year t - 1 remaining from capital additions made in year t - s} \\
&= \frac{N-s+1}{N} \cdot a_{t-s}
\end{aligned}
$$

then

$$CK^{SL} = \sum\nolimits_{s=1}^{N} \left[r_t \cdot WKA_{t-1} \cdot xk_{t-1}^{t-s} - \left(WKA_t - WKA_{t-1}\right) \cdot xk_{t-1}^{t-s} + WKA_t \cdot \frac{1}{N} \cdot \frac{N}{N-s+1} \cdot xk_{t-1}^{t-s} \right]$$

Defining the total stock of capital at the end of year *t* as

$$xk_{t-1} = \sum\nolimits_{s=1}^{N} xk_{t-1}^{t-s} = \sum\nolimits_{s=1}^{N} \frac{N-s+1}{N} \cdot a_{t-s}$$

it follows that

$$\begin{aligned} CK_t^{SL} &= \left[r_t \cdot WKA_{t-1} - \left(WKA_t - WKA_{t-1}\right)\right] \cdot \sum\nolimits_{s=1}^{N} xk_{t-1}^{t-s} + WKA_t \cdot \sum\nolimits_{s=1}^{N} \frac{1}{N-s-1} \cdot xk_{t-1}^{t-s} \\ &= \left[r_t \cdot WKA_{t-1} - \left(WKA_t - WKA_{t-1}\right)\right] \cdot xk_{t-1} + WKA_t \cdot \sum\nolimits_{s=1}^{N} \frac{xk_{t-1}^{t-s}}{xk_{t-1}} \cdot \frac{1}{N-s-1} \cdot xk_{t-1} \\ &= WKS_t^{SL} \cdot xk_{t-1} \end{aligned}$$

where

$$\begin{aligned} WKS_t^{SL} &= r_t \cdot WKA_{t-1} - \left(WKA_t - WKA_{t-1}\right) + d_t^{SL} \cdot WKA_t \\ &= \textit{capital service price for straight line depreciation} \end{aligned}$$

and

$$\begin{aligned} d_t^{SL} &= \sum\nolimits_{s=1}^{N} \frac{xk_{t-1}^{t-s}}{xk_{t-1}} \cdot \frac{1}{N-s-1} \\ &= \textit{depreciation rate for straight line depreciation} \end{aligned}$$

It can be seen that a capital service price also exists for the case of straight line depreciation. As in the case of geometric decay, it is higher the higher is the interest rate, depreciation rate, and asset price and the slower is asset price growth. The capital service price for straight line depreciation differs from that for geometric decay only with regard to the depreciation factor. Unlike the geometric decay case, the depreciation factor isn't constant. Rather, it is a weighted average of the depreciation rates for plant components of different vintages. The depreciation rate for plant of a given vintage is greater the greater is its age. The overall depreciation rate thus depends on the vintage distribution of plant. The older is plant on average, the higher is the overall depreciation rate and capital service price. The depreciation rate of a DB, for instance, is higher the greater is the share of allocation statement assets in the replacement value of all assets.

The methodology raises the issue of how a depreciation rate should be calculated for a New Zealand DB. In this regard, note that

$$\begin{aligned}
\frac{\textit{Replacement Value Depreciation}_t}{\textit{Net Plant Replacement Value}_{t\text{-}1}\cdot\dfrac{WKA_t}{WKA_{t-1}}} &= \frac{\sum_{s=1}^{N} WKA_t \cdot \dfrac{1}{N}\cdot a_{t-s}}{WKA_t\cdot xk_{t-1}\cdot\dfrac{WKA_t}{WKA_{t-1}}} \\
&= \frac{\sum_{s=1}^{N} \dfrac{1}{N}\cdot a_{t-s}}{xk_{t-1}} \\
&= \sum_{s=1}^{N} \frac{1}{N}\cdot\frac{N}{N-s+1}\cdot\frac{x_{t-1}^{t-s}}{xk_{t-1}} \\
&= \sum_{s=1}^{N} \frac{xk_{t-1}^{t-s}}{xk_{t-1}}\cdot\frac{1}{N-s+1} \\
&= d_t^{SL}
\end{aligned}$$

Thus, the ratio of current period replacement value depreciation to the (inflation adjusted) net plant replacement value at the end of the previous year provides a good approximation to the straight-line economic depreciation rate.