Differentiating this identity with respect to time yields the following:

$$\sum_{i=1}^{N} \dot{p}_i Q_i + \sum_{i=1}^{N} p_i \dot{Q}_i = \sum_{j=1}^{M} \dot{w}_j R_j + \sum_{j=1}^{M} w_j \dot{R}_j \ ,$$

where a dot ($\cdot$) indicates a derivative with respect to time. Dividing both sides of the equation by the value of output ($\mathrm{Re}\,v = \sum_i p_i Q_i$ or $C = \sum_j w_j R_j$), we obtain

$$\sum \dot{p}_i \left(\frac{Q_i}{REV} \right) + \sum \dot{Q}_i \left(\frac{p_i}{REV} \right) = \sum \dot{w}_j \left(\frac{R_j}{C} \right) + \sum \dot{R}_j \left(\frac{w_j}{C} \right),$$

where REV and C denote revenue and cost. If rev_i denotes the revenue share of output i and c_j denotes the cost share of input j, then

$$\sum_i rev_i dp_i = \sum_j c_j dw_j - \left[\sum_i rev_i dQ_i - \sum_j c_j dR_j \right] , \tag{1}$$

where d denotes a percentage growth rate: $dp_i = \dot{p}_i / p_i$. The first term in equation (1) is the revenue-weighted average of the rates of growth of output prices, and the second is the cost-weighted average of the rates of growth of input prices. The term in brackets is the difference between weighted averages of the rates of growth of outputs and inputs. It thus is a measure of the change in TFP. Rewriting the equation for clarity, we see that

$$dp = dw - dTFP \, .$$

In words, the theory underlying the annual price cap adjustment formula implies that the rate of growth of a revenue-weighted output price index is equal to the rate of growth of an expenditure-weighted input price index plus the change in total factor productivity (TFP). This equation shows that TFP is the appropriate foundation for a productivity target in the price cap plan: if the price cap plan begins with revenues which just match costs for a company, and if it attains the same productivity growth as the industry (measured in terms of TFP), then that company's revenues will continue to match its costs.

Applying this rule more generally to admit the possibility of exogenous cost events outside of a regulated company's control, we may write

$$dp^* = dw - dTFP$$

where dp^* represents the annual percentage change in industry output prices inclusive of these exogenous costs, and dw represents the annual percentage change in input prices. To raise or lower industry output prices in order to track exogenous changes in cost, we write

(2) $$dp = dw - dTFP + Z^*$$

where dp represents the annual percentage change in industry output prices adjusted for exogenous cost changes, and Z^* represents the unit change in costs due to external circumstances.[4] Thus to keep the revenues of the industry equal to its costs despite changes in input prices, the price cap formula should (i) increase industry output prices at the same rate as its input prices less the target change in productivity growth, and (ii) directly pass through exogenous cost changes.

Equation (2) sets the allowed price change as input price changes less TFP growth adjusted for exogenous cost pass-throughs. If the economy-wide inflation rate were *assumed* to be the measure of the industry's input price growth and the X-factor was similarly *assumed* to be its TFP growth target, equation (2) would indeed be the basis for the ideal price adjustment formula. However, these two assumptions are incorrect:

(a) Broad inflation measures capture national *output* price growth, not the industry's input price growth. So even if the industry is a microcosm of the whole economy, a measure which captures national output price growth would not be an appropriate measure of its input price growth.[5]

(b) The X-factor is a target TFP growth rate relative to the economy as a whole (or relative to the TFP growth already embodied in national output price growth). The change in TFP in equation (2) is the absolute TFP growth for the industry. Again, unless economy-wide TFP growth is zero, the X-factor is not equal to $dTFP$.

To get from equation (2) to the price adjustment formula, we must compare the productivity growth of the industry with the productivity growth of the whole economy. It is difficult to measure input price growth objectively. No agency of which we are aware maintains an index of industry-specific input prices. Further, a productivity adjustment based on company-provided calculations of changes in their own input price index would be controversial and would not necessarily be based on information outside the company's control. However, by comparing productivity growth of the industry with that of the whole economy, we avoid the difficulty of measuring input price growth.

---

[4] Note that Z^* can be positive or negative.

[5] Recall that input price growth differs from output price growth by the growth in TFP. Only if national productivity growth were zero could GDP_PI be a good measure of national input price growth.

For the economy as a whole, the relationship among input prices, output prices, productivity, and exogenous cost changes can be derived in the same manner as it was derived in equation (2) above:

(3) $$dp^N = dw^N - dTFP^N + Z^{*N}$$

where dp^N is the annual percentage change in a national index of output prices; dw^N is the annual percentage change in a national index of input prices; $dTFP^N$ is the annual change in the economy-wide total factor productivity and Z^{*N} represents the change in national output prices caused by the exogenous factors included in equation (2). Subtracting equation (3) from equation (2) gives

$$dp - dp^N = \left[dw - dw^N\right] - \left[dTFP - dTFP^N\right] + \left[Z^* - Z^{*N}\right],$$

or

(4) $$dp = dp^N - \left[dTFP - dTFP^N + dw^N - dw\right] + \left[Z^* - Z^{*N}\right],$$

which simplifies to

(5) $$dp = dp^N - X + Z \ .$$

If the industry achieves a productivity target of X and experiences exogenous cost changes given by Z, the price change that keeps earnings constant is given by equation (5). This price change is given by:

1. the rate of inflation of national output prices dp^N,
2. less a fixed productivity offset, the X-factor, which represents a target productivity growth differential between the annual TFP growth of the industry and the whole economy,[6]
3. plus exogenous unit cost changes, written as the difference between the effects on the industry and economy-wide unit costs of the exogenous event.

To use the industry's productivity performance as a target for an individual company, rewrite equation (5) into the formula:

(6) $$PCI_t = PCI_{t-1} \times \left[1 + GDP_PI_t - X \pm Z_t\right],$$

---

[6] This differential is equal to the difference between the electricity industry and economy-wide TFP growth rates only if the rates of input price growth are the same for the industry and the nation: i.e., if $dw = dw^N$.

Where PCI_t is the value of the index used to update the price cap in year t, GDP_PI_t is the price index for Gross Domestic Product (or some other comparable index), and Z_t is the difference in the effects of exogenous changes on a specific company and on the rest of the economy.

A.2. Interpretation of the Formula

In words, using the above formula to limit price increases has the property that earnings remain the same if a company's achieved productivity differential just meets the historical target X-factor. Thus a company must perform as well against economy-wide average TFP growth today as the industry as a whole has historically performed in comparison with economy-wide average TFP growth. If a company's productivity growth falls short of the target, its earnings will fall; if it exceeds the target, its earnings will rise. The price adjustment formula that sets this target adjusts output prices by: (1) the change in a national index of output prices less (2) the TFP growth target, measured as the difference between the change in industry TFP and that of the nation as a whole,[7] plus (3) the difference between the effect of exogenous changes on a company's costs and on the costs of the nation as a whole.

Thus the historical relative TFP growth of the industry and the whole economy is taken as the target for TFP growth relative to the whole economy. National output price growth and exogenous cost changes are measured annually, but the *X-factor* is fixed as the target amount by which TFP growth should exceed historical economy-wide TFP growth. If a company exceeds its productivity target, its earnings will rise, and if it falls short of its productivity target, its earnings will fall. This system of rewards and punishments sets up the same incentives as an unregulated firm would face in a competitive market, where failure to match industry-average productivity growth results in lower earnings and exceeding industry average productivity growth leads to increased earnings.

For discussing issues involving the empirical measurement of TFP, two issues remain core to this theoretical exposition: (1) the only relevant productivity measure is TFP *growth*, not the *level* of TFP (about which this exposition says nothing); and (2) it is only the *industry average* TFP growth mimics the constraints faced by firms in a competitive market.

---

[7] Adjusted for possible differences between input price growth rates for the industry and the nation.

5

ELUSIVE EFFICIENCY AND THE X-FACTOR IN INCENTIVE REGULATION: THE TÖRNQVIST V. DEA/MALMQUIST DISPUTE

Jeff D. Makholm

Introduction

Incentive-based regulation is practiced worldwide, and all applications of it require some form of efficiency or productivity measurement—the *X-factor*. Including this factor in a multi-year regulatory formula allows the formula to survive intact for several years, and this longer regulatory lag between tariff reviews strengthens the incentives on firm performance. The factor, an index number, is intended to permit prices to move between tariff reviews according to an objective and reliable pattern. Differing opinions have arisen, however, on which index number to use.

One index number, the Malmquist Index, has generated considerable interest in some regions (particularly in Australia and Europe) because of its ostensible ability, when used in conjunction with data envelopment analysis (DEA), to distinguish readily between technical change for an industry (which the X-factor is generally held to measure) and efficiency for a particular firm. However, the DEA/Malmquist procedure for separating individual firm efficiency from technical change is inherently unreliable for identifying how inefficient a firm is. Neither the quality of data for regulated firms, nor the essentially idiosyncratic nature of such firms, supports an analysis of the *level* of efficiency of individual utilities. To the extent that regulators attempt to use the DEA/Malmquist procedure to set tariffs to reflect "efficient firm" standards, they inject unsupportable subjectivity and an unreliable methodology into a tariff-making process. The only reliable alternative is to estimate the X-factor

directly by measuring long-run rates of change in efficiency indices. The Törnqvist index is best suited to this process, but other similar indices offer similar results.

The X-Factor in the Theory of Price Cap Regulation

Incentive regulation allows automatic or formulaic adjustment to regulated prices between tariff cases. That is, the plan controls the rate of change of the regulated firm's tariffs by adjusting a price cap (or revenue cap) annually according to a predetermined formula. The purpose is to ensure that price changes reflect changing costs the same way as in competitive markets: (1) Changes in industry prices track changes in industry costs and (2) the changes in an individual firm's prices relative to its costs differ from an industry average if its productivity growth differs from the average productivity growth of its industry.[1] This difference between the rate of change in industry prices and in individual firm costs causes a variation in profits. This is the carrot or stick with which the competitive process rewards efficiency gains and punishes firms that are slow to innovate, to reduce costs, or to respond to consumer demands.

The Place of Incentive Regulation in Regulatory Economics

Incentive regulation has been a key part of utility regulation for over 25 years. In that time, many regulated companies in North America and virtually all newly privatized companies around the world embraced under a variety of labels some form of incentive regulation. Generally, incentive regulation plans are characterized by a definite plan period, automatic adjustment for inflation, a productivity adjustment (the X-factor), and sometimes a way to share monetary gains between utilities and customers and/or reward (or penalize) quality of service changes. It is the X-factor that embodies the competition-like constraint to which regulated companies are held under incentive regulation. Imposing that constraint extends the period between tariff cases in an acceptable way and provides the time for cost-savings or sales maximizing incentives to pay off for investors. The X-factor is not an incentive in itself, but it permits regulatory formulae to stay in place longer—and that provides the incentive for more efficient long-term decisions on costs, sales, and investments.

In the early application of price cap regulation in the UK, a general notion existed that the X-factor was a variable simply subject to the regulator's choice. For example, Beesley and Littlechild describe the X-factor as "...a number specified by the government,"[2] as if it were some kind of

bureaucratic target. More recent consensus is that the X-factor derives from a regulatory regime designed to limit monopoly utility prices over a defined number of years in a way that mimics the constraints that a competitive firm would face. In discussions on setting the appropriate X-Factor, economists generally agree with the theory set out above and on the two central elements of the relevant Total Factor Productivity (TFP) measures.[3] For example, Loube and Navarro confirm that a price cap plan begins with prices set so that the value of total inputs (including a normal return on capital) equals the value of total output for the company as well as the industry.[4] A number of writers confirm that the purpose of the price cap adjustment formula is to ensure that the constraint of regulated prices mimics the pressures that competition would place on a firm.[5] General agreement also exists among economists that the relevant TFP measure should be based on industry- rather than firm-specific productivity measures.[6]

Theoretical X-Factor Formulation[7]

The standard formulation for implementing price cap regulation is given by equation (5) from Appendix A:

$$dp = dp^N - X + Z \tag{1}$$

where dp denotes a percentage growth rate in price, dp^N is the annual percentage change in a national index of output prices, and Z represents the change in unit costs due to external circumstances (which can be positive or negative).

If the industry achieves a productivity target of X and experiences exogenous cost changes given by Z, the price change that keeps earnings constant is given by equation (1). This price change is given by:

1. the rate of inflation of national output prices dp^N,
2. less a fixed productivity offset, the X-Factor, which represents a target productivity growth *differential* between the annual TFP growth of the industry and the whole economy,[8]
3. plus exogenous unit cost changes, written as the difference between the effects on the industry and economy-wide unit costs of the exogenous event.

To use the industry's productivity performance as a target for an individual company, rewrite equation (1) into the formula:

(2) $$PCI_t = PCI_{t-1} \times [1 + GDP - PI_t - X \pm Z_t],$$

where PCI_t is the value of the price cap index in year t, Z_t is the difference in the effects of exogenous changes on a specific company and on the rest of the economy, and $GDP-PI$ is the national output price index (i.e., "gross domestic product price index").

Simply put, the effect of using the above formula to limit price increases is that earnings remain the same if a company's achieved productivity differential just meets the target X-Factor. Thus a company must perform as well against economy-wide average TFP growth today as the industry as a whole has historically performed in comparison with economy-wide average TFP growth. If a company's productivity growth *falls short of the target, its earnings will fall; if it exceeds the target, its* earnings will rise. The price adjustment formula that sets this target adjusts output prices by: (1) the change in a national index of output prices less (2) the TFP growth target, measured as the difference between the change in industry TFP and that of the nation as a whole, plus[9] (3) the difference between the effect of exogenous changes on a company's costs and on the costs of the nation as a whole.

Thus, the historical relative TFP growth of the industry and the whole economy is taken as the target for the firm's TFP growth relative to the whole economy. National output price growth and exogenous cost changes are measured annually, but the X-Factor is fixed as the target amount by which TFP growth should exceed historical economy-wide TFP growth. This system of rewards and punishments sets up the same incentives as an unregulated firm would face in a competitive market, where failure to match industry average productivity growth results in lower earnings, and exceeding industry average productivity growth leads to increased earnings.

When turning to the empirical measurement of TFP, it is important to keep two points in mind: (1) the only relevant productivity measure is the *change* in TFP, not the *level* of TFP (discussed in Appendix A); and (2) it is only the *industry average* TFP growth that mimics the constraints faced by firms in a competitive market.

"X-Factor Quantification" and Index Numbers

This X-Factor lies at the heart of the discussion regarding the possible use of the DEA/Malmquist index to regulate utility prices as a component of price cap regulation. The X-Factor is ultimately an index number. Index numbers are found throughout the economy, expressing the value of some

entity, like prices or gross national product, at a given period of time and in absolute number form, but related to some base period. Objectively determined incentive regulation uses such index numbers as the X-factor to reflect industry productivity growth.

The first issue concerning the empirical foundation of the X-factor is the use of long historical time trends in its calculations. The conventional assumption among productivity analysts is that the industry productivity and input prices are characterized by a valid and stable trend. This basic view of long-term trends has been adopted by many academic researchers who have studied macroeconomic time series such as GNP, prices, wages, unemployment rates, money stock, interest rates, etc. The issue of whether "structural breaks" disrupt such long-term trends has attracted considerable academic interest,[10] but it would appear that the stable trend hypothesis is a strong one and is most consistent with the search for objectivity in the calculation of a suitable X-factor. Using the longest historical data series consistent with available data allows analysts to identify the magnitude of the trend most reliably.

Since price cap regulation was introduced in the UK in the 1980s, and subsequently in the US in the early 1990s, considerable discussion has attended the choice of the index number to mimic productivity. Most of the literature on index numbers for productivity measurement pre-dates the use of such information in incentive regulation plans. Indeed, all three of the productivity index numbers in general use for price cap regimes were formulated by their named authors decades ago. They are the Fisher Ideal index, used by the Federal Communications Commission (the FCC) for telecommunications incentive regulation in the United States, the Törnqvist[11] index, which forms the basis for many electric utility TFP studies, and the Malmquist index, to which regulators in the Netherlands and Germany have referred on occasion (albeit for a different reasons).

Comparing the Törnqvist with Malmquist Indexes

The popularity of the Törnqvist index follows from its association with "translog" production and cost functions. Simply put, translog functions (which are functions squared in logarithms) were the first to allow economists to study empirically the "U-shaped" cost curves of real-life firms. With such functions, scale and substitution economies could be investigated empirically rather than assumed theoretically. With such flexible, empirically developed models of production technology as a foundation, the theoretical base for index numbers that reflect such production

technology is very strong.[12] The translog multilateral productivity index[13] forms the basis for modern TFP studies in the electric power industry, including NERA's.

The Malmquist index in modern regulatory literature is usually mentioned alongside the Törnqvist index in the literature on index number theory. The two indexes are indeed close theoretical cousins. For regulatory purposes, however, various analysts have seized upon a particular feature of the Malmquist index that the Törnqvist does not share: the purported ability to measure the extent of inefficiency of individual utilities against supposedly more efficient peers. However, the use of DEA procedures along with the Malmquist index for the purpose of assessing individual firm efficiencies is not based on index number theory, nor is it consistent with the empirical applications for which it appeared in the literature. In this section I review the use of the Malmquist index by academic efficiency analysts as well as by index number theorists. I show that the use of that index in conjunction with DEA analyses to judge the efficiency of individual utilities is a particular misuse of an index number method, for which no support appears in the theoretical or empirical academic economic literature.

The Malmquist index arose in productivity theory as a more general, less restrictive, way of representing how a production function moves over time. Although it lends itself to the practice, it was not intended as a tool to "differentiate between technical change and changes in productivity."[14] It is not a use for which index number theorists investigated the Malmquist index nor is it supported in that literature.

In general, the Malmquist index measures the change in an industry's total factor productivity over time. It accounts for the fact that technology (i.e., best practice) is continually changing and that a firm's efficiency performance (relative to best practice) is also subject to change. For this reason, calculating this index requires a panel of data for the identification of both technological change and variations in firm efficiency. The Malmquist index describes productivity growth in terms of two components: (1) movements in the best practice frontier (i.e., technological change) and (2) shifts in firm efficiency that narrow or widen the gap between actual and frontier performance.

In comparison, the Törnqvist index does not decompose productivity growth in terms of technological change and efficiency "catch up," but rather in terms of the respective contributions of output and input growth (and their individual components if there is more than one) to the

final result. Another important difference between these two estimation methods is that the Törnqvist index relies on cost shares or other value-based weights, which implies the use of price information in addition to quantity series, whereas the Malmquist index only requires quantity indexes to calculate productivity. Other than these differences, and provided that adequate data are available, the Törnqvist and Malmquist indexes should provide similar overall results for industry TFP.

The problem with the use of the Malmquist index is that it enables analysts to make assertions about firm-specific efficiency relating to its two components—one representing the "technology" and the other representing the "firm." The existence of the two components has led analysts to draw conclusions about the efficiency of a particular firm with respect to an industry standard—something that incentive regulation does not call for and that the quality of data to investigate the X-Factor does not support.

Data Envelopment Analysis (DEA) and the X-Factor

DEA combines multiple input and output measures (both monetary and physical) to generate an overall efficiency measure for a company. Mathematical programming methods allow researchers to apply quantitative information of a company and its peer group (i.e., the comparators) to determine relative efficiency performance.

Figure 1 illustrates the basic DEA approach. This figure displays an input-oriented[15] efficiency measurement for a group of 10 companies, which assumes that there is one type of output (e.g., MBTUs delivered) and two kinds of input (e.g., capital and labor). This type of efficiency measure considers the degree to which input quantities can be proportionally reduced without changing the output quantities. The figure plots the combination of inputs (x_1 and x_2) that each company employs to produce a unit of output, which for simplicity is normalized equal to one. Based on the actual behavior of the 10 companies, an envelope curve or efficiency frontier (shown in the Figure) is identified, reflecting the industry best practice. If the production function (which in this case has only two inputs) were to capture all the relevant determinants of cost, then the closer a firm is located to this curve the higher is its level of efficiency. In principle, firms that are located further out can produce the same amount of output with fewer inputs, bringing them closer to the origin and the achievement of higher efficiency. Theoretically, each firm's efficiency level can be measured empirically. For instance, Firm P's score

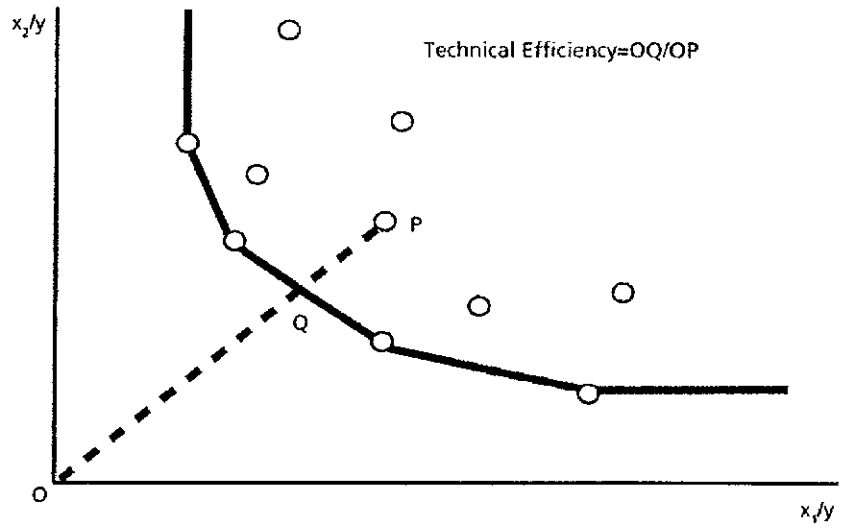


Figure 1. Efficiency Measurement with Data Envelopment Analysis (DEA)

is equal to the ratio OQ/OP. If a firm is located on the frontier, then it obtains the highest possible score, which is equal to one.

Certain analysts (and some regulators) have taken the relative positions on such graphs as Figure 1 as indicating what the X-Factor should be for a particular firm, for instance, by calculating an "efficiency score" for each company equal to the distance from the "efficiency" line. However, these conclusions are inconsistent with the price cap theory that uses a competitive type of constraint for multiyear regulated prices precisely because such conclusions ignore the fact that relative productivity levels are elusive when particular utilities are highly idiosyncratic. Any conclusions about relative efficiency are limited by the caveat that the DEA analysis measures all relative cost drivers. In practice, for utilities in different locations, with different histories, serving different kinds of customers, this is quite obviously not the case. That is, while such an analysis can be useful in gauging the relative efficiency in very similar operations (like McDonald's franchises, which operate from similar shops selling similar, or even identical, products), the same is definitely not true for different utilities selling to different customer bases in different regions of a country (or the world). In such cases, the gap between the company and the frontier could as well be due to any factors not recog-

nized in the analysis and is not necessarily a measure of "inefficiency levels" or "productivity levels."

The DEA/Malmquist Procedure in Efficiency Analyses

Users of the Malmquist index number in regulatory settings frequently refer to the "seminal" 1978 paper by Charnes, Cooper, and Rhodes.[16] This paper is about measuring efficiency "with special reference to possible use in evaluating public programs."[17] In that paper, Charnes, et al. use DEA as a method to chart the comparative efficiency of public programs (decision making units—DMUs). That analysis (the graphical representation is shown above in Figure 1) measures the distance between the presumed efficiency frontier and the position of an individual DMU, implying inefficiency in that unit. They do, however, warn of the method's limitations outside of the public setting, saying

> One limitation may arise because of lack of data availability at individual [decision making unit] levels. This is likely to be less of a problem in public sector, as contrasted with private sector, applications. ... Our measure is intended to evaluate the accomplishments, or resource conservation possibilities, for every DMU with the resources assigned to it.[18]

By acknowledging the need to standardize the "resources assigned to it," as in the case of their school district example, the authors recognize the limitations of their suggested DEA method in situations where input choice or environmental factors cannot be controlled. Despite its limitations for private firms, DEA analysis is a direct analog to the Malmquist index, where the "distance" of a particular firm's observation (in a particular year or for an average of years) is compared to the "envelope." Like DEA analysis generally, the most fundamental problem with using the Malmquist index in this way for different network utilities is that neither all the input choices nor all the environmental factors can be controlled. Individual regulated firms exist in specific local surroundings. The myriad important factors (age, location, vintage of capital stock, idiosyncratic local regulation, etc.) create cost or output differences for particular utilities that their regulatory data does not (and can never hope to) capture. This type of comparison confuses these ubiquitous differences in conditions for significant differences in efficiency.

Federico went right to the heart of the problem of ignoring variations in environment issues:

> In spite of its nice theoretical properties, the Malmquist index is subject to all the shortcomings of conventional measures. It does not take into account environmental [factors], nor possible distortions from the use of benchmark years and the two measures of technical change differ if technical progress on the "frontier" is not neutral. On top of this, the Malmquist index (as the multi-country production function estimates) assumes that all units can attain the same level of production given their factor endowment—i.e., that they belong to the same production function. This assumption may not hold in agriculture, where feasible techniques heavily depend on environment.[19]

What is true of agriculture is true of any business—including network utilities—where local conditions dictate the precise form of investments and operations. The question of environmental factors cannot be disentangled from efficiency in either DEA analysis or its Malmquist equivalent. Sena reviews the various methods and warns about these environmental variables in evaluating the results of either DEA or Malmquist models that purport to identify efficiency for individual not on the frontier:

> However, the main weakness of DEA (namely that it is a deterministic method) is still there and so the computed distance functions may include the effect of factors not related to technical efficiency and technical change. ... The best option left to the researcher is to try to specify the DEA model (underlying the Malmquist index) in the best possible [way]... to minimize the impact of external factors on the computed distance functions.[20]

Sena also identifies another problem with the use of DEA analyses underlying the Malmquist index—that of stochastic shocks in the data:

> DEA does not allow us to model stochastic shocks to production i.e., it is deterministic. Therefore the computed efficiency scores may be biased by factors which are external to the production process. Not surprisingly, some attempts have been made to incorporate stochastic components into the linear programming problem. ...The

> data requirements of the chance-constrained efficiency measurement, however, are too many. Indeed it is necessary to have information on the expected values of all variables, along with their variance and covariance matrices and the probability levels at which feasibility constraints are to be satisfied. Therefore, this approach is too informationally demanding to be implemented easily.[21]

The issues associated with bias due to stochastic shocks are genuine and highly problematic for DEA analyses with electric utility data. Appendix C to this paper contains TFP data computed for a 1986 study of electric utilities,[22] using Form 1 data from the Federal Energy Regulatory Commission (the FERC) using the Uniform System of Accounts.[23] The productivity growth figures displayed in the Appendix, generated with a Törnqvist aggregation using the most reliable and consistent data for 39 electric utilities across 11 years, still shows considerable levels of stochastic shocks, particularly in year-to-year comparisons. For example, Kentucky Power for the four years 1973 through 1976 shows TFP yearly growth rates of −22.4 percent, 20.6 percent, −20.2 percent and 28.1 percent. The average TFP growth for Kentucky Power for the 11 years is 3.2 percent, and for those four particular years is 1.6 percent. But a DEA analysis of cost levels in 1974 or 1976 would incorporate very high productivity growth—owing only to stochastic shocks that were reversed in the next year—and those numbers make other companies in those years seem less productive by comparison.

Empirical data from academic TFP studies show that even the highest quality data (from the U.S. Uniform System of Accounts) produces TFP index growth rates for individual companies that are highly sensitive to vagaries and judgments on how company data is reported to governmental agencies. Individual data points for specific companies and years in industry-wide TFP analysis are notoriously unstable, even in the best of circumstances (see the data in Appendix C). The DEA envelope process, or the Malmquist index method, necessarily picks up the instability in individual data points and represents a stochastic error as a shift in technology. Simple noise among a cross-section would be taken as a change in the frontier—an advance of productivity. The more "noise" there is in the data, the more it pushes the envelope, implying inefficiency where none would otherwise be shown to exist. Thus, a simple DEA Malmquist analysis would treat the advances of companies in panel data TFP analyses as a shift in technology and would consider retreats as inefficiency.

In any event, to the extent that particular firms enter and leave the technology envelope on a short-term basis (which is indeed the case with the TFP data I analyzed in Appendix C), that envelope has no reliable significance as an indication of technological possibilities. Given that the envelope encapsulates unreliable individual data points and overstated technical progress, any conclusions based on the technological change and the efficiency "catch up" components of the Malmquist index would be highly unreliable.

Nevertheless, jurisdictions continue to rely on the Malmquist index in their DEA analyses. The Independent Pricing and Regulatory Tribunal (IPART) in New South Wales, Australia, has commissioned a number of regulatory benchmarking studies using the DEA/Malmquist technique.[24] These studies measure DEA production frontiers as a yardstick against which to measure the relative performance of the distributors under IPART's jurisdiction. Recent analyses have also been performed comparing the efficiency of individual Dutch electricity generators.[25] Another analysis was performed for German electricity distributors in the Federal network regulator's (BNA's) 2006 report on incentive regulation.[26] Scandinavian regulators routinely use such studies. These regulatory applications reflect a similar use of the DEA/Malmquist technique, with a similar justification:

> The Malmquist index ... can be decomposed so that the change in total factor productivity may be separated into a shift of the frontier (technical change) and a shift relative to the frontier (change in efficiency).[27]

This reasonable-sounding goal is contrary to the role of productivity in the theory of incentive regulation, as outlined in Section II and Appendix A, and, even if this were a valid pursuit in incentive regulation, it is contrary the advice of Federico and Sena regarding the difficulty of standardizing environmental factors. DEA's adherents seem to like the ease with which it provides "efficiency scores" for particular utilities. But that ease of calculation both contradicts the theory upon which incentive regulation rests and remains inconsistent with the kind of data available for utilities to which DEA is applied.

Summary of the DEA/Malmquist Procedure

Given the characteristics listed above of the Malmquist index and of DEA, any plan to base a price cap on the separation of technological change

from company efficiency is going to run into problems than cannot be overcome in an objective manner. The DEA/Malmquist procedure cannot possibly control for all the environmental factors that determine a company's performance. Moreover, random shocks ("noise") in these unexplained factors can lead to further downward bias in the "frontier" and hence to a further underestimate of a company's performance.

The X-Factor remains a highly useful part of incentive regulation. The DEA/Malmquist procedure, however, is a devilishly convenient but ultimately unreliable procedure, inconsistent with the principles of incentive regulation. It is based on assumptions of production technologies and not on theory supported by the economic literature or valid empirical work. It has no support in the economic literature on the theory of index numbers and is contrary to the accepted theory regarding the incentives that price caps are supposed to embody. It is also contrary to the use of the DEA/Malmquist procedure in the analysis of nonregulated businesses where in contrast to network operations the inputs are controlled, and it has manifestly clear and unavoidable empirical problems.

Appendix A

The Derivation of the PBR formula:

Assume the price cap plan begins with appropriate prices so that the value of total inputs (including a normal return on capital) equals the value of total output for the company as well as the industry. For the industry, we can write this relationship as

$$\sum_{i=1}^{N} p_i Q_i = \sum_{j=1}^{M} w_j R_j$$

where the industry has N outputs ($Q_i, i=1,\ldots,N$) and M inputs ($R_j, j=1,\ldots,M$) and where p_i and w_j denote output and input prices, respectively. We want to calculate a productivity target for a company based on industry average productivity growth.

Differentiating this identity with respect to time yields

$$\sum_{i=1}^{N} \dot{p}_i Q_i + \sum_{i=1}^{N} p_i \dot{Q}_i = \sum_{j=1}^{M} \dot{w}_j R_j = \sum_{j=1}^{M} w_j \dot{R}_j$$

where a dot (·) indicates a derivative with respect to time. Dividing both sides of the equation by the value of output ($Rev = \sum_i p_i Q_i$ or $C = \sum_j w_j R_j$), we obtain

$$\sum \dot{p}_i \left(\frac{Q_i}{REV}\right) + \sum \dot{Q}_i \left(\frac{p_i}{REV}\right) = \sum \dot{w}_j \left(\frac{R_j}{C}\right) + \sum \dot{R}_j \left(\frac{w_j}{C}\right)$$

where REV and C denote revenue and cost. If rev_i denotes the revenue share of output i, and c_j denotes the cost share of input j, then

$$\sum_i rev_i \, dp_i = \sum_j c_j dw_j - \left[\sum_i rev_i \, dQ_i - \sum_j c_j dR_j\right] \tag{1}$$

where d denotes a percentage growth rate: $dpi = \dot{p}_t/p_t$. The first term in equation (1) is the revenue-weighted average of the rates of growth of output prices, and the second is the cost-weighted average of the rates of growth of input prices. The term in brackets is the difference between weighted averages of the rates of growth of outputs and inputs. It thus is a measure of the change in TFP. Rewriting the equation for clarity, we see that

$$dp = dw - dTFP.$$

In other words, the theory underlying the annual price cap adjustment formula implies that the rate of growth of a revenue-weighted output price index is equal to the rate of growth of an expenditure-weighted input price index plus the change in total factor productivity (TFP). This equation shows that TFP is the appropriate foundation for a productivity target in the price cap plan: If the price cap plan begins with revenues that just match costs for a company, and if it attains the same productivity growth as the industry (measured in terms of TFP), then that company's revenues will continue to match its costs.[28]

Applying this rule more generally to admit the possibility of exogenous cost events outside of a regulated company's control, we may write

$$dp^* = dw - dTFP$$

where dp^* represents the annual percentage change in industry output prices inclusive of these exogenous costs, and dw represents the annual percentage change in input prices. To raise or lower industry output prices in order to track exogenous changes in cost, we write

$$dp = dw - dTFP + Z^* \tag{2}$$

where *dp* represents the annual percentage change in industry output prices adjusted for exogenous cost changes, and Z^* represents the unit change in costs due to external circumstances.[29] Thus, to keep the revenues of the industry equal to its costs despite changes in input prices, the price cap formula should (1) increase industry output prices at the same rate as its input prices less the target change in productivity growth, and (2) directly pass through exogenous cost changes.

Equation (2) sets the allowed price change as input price changes less TFP growth adjusted for exogenous cost pass-throughs. If the economy-wide inflation rate were *assumed* to be the measure of the industry's input price growth and the X-Factor were similarly *assumed* to be its TFP growth target, equation (2) would indeed be the basis for the ideal price adjustment formula. However, these two assumptions are incorrect:

1. Broad inflation measures capture national *output* price growth, not the industry's input price growth. So even if the industry were a microcosm of the whole economy, a measure that captures national output price growth would not be an appropriate measure of its input price growth.[30]
2. The *X-Factor* is a target TFP growth rate relative to the economy as a whole (or relative to the TFP growth already embodied in national output price growth). The change in TFP in equation (2) is the absolute TFP growth for the industry. Again, unless economy-wide TFP growth is zero, the *X-Factor* is not equal to *dTFP*.

To get from equation (2) to the price adjustment formula, we must compare the productivity growth of the industry with the productivity growth of the whole economy. It is difficult to measure input price growth objectively. We are unaware of any agency that maintains an index of industry-specific input prices. Further, a productivity adjustment based on company-provided calculations of changes in their own input price index would be controversial and would not necessarily be based on information outside the company's control. However, by comparing productivity growth of the industry with that of the whole economy, we avoid the difficulty of measuring input price growth.

For the economy as a whole, the relationship among input prices, output prices, productivity, and exogenous cost changes can be derived in the same manner as it was derived in equation (2) above

(3) $$dp^N = dw^N - dTFP^N + Z^{*N}$$

where dp^N is the annual percentage change in a national index of output prices, dw^N is the annual percentage change in a national index of input prices, $dTFP^N$ is the annual change in the economy-wide total factor productivity, and Z^{*N} represents the change in national output prices caused by the exogenous factors included in equation (2). Subtracting equation (3) from equation (2) gives

$$dp - dp^N = [dw - dw^N] - [dTFP - dTFP^N] + [Z^* - Z^{*N}],$$

or

(4) $$dp = dp^N - [dTFP - dTFP^N + dw^N - dw] + [Z^* - Z^{*N}]$$

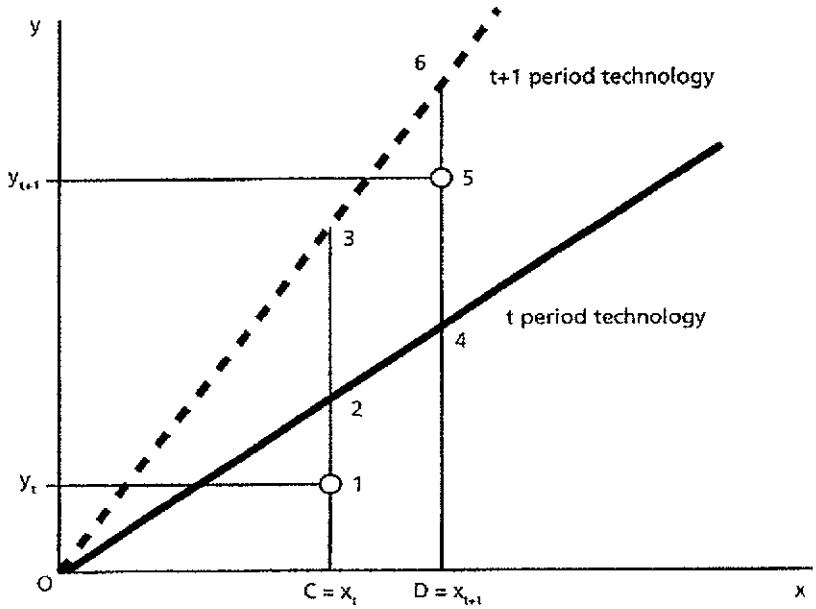
which simplifies to

(5) $$dp = dp^N - X + Z.$$

Appendix B

The Malmquist Index

Figure 2 illustrates the measurement of the Malmquist index, assuming an output-oriented efficiency measure and a constant return to scale technology. To simplify the exposition, I consider one output and only one type of input category. Figure 2 shows the efficiency frontier and a firm's output/input combination for two different time periods. Point 1 refers to initial period (time t), and point 5 pertains to the second period (time t+1). Based on the t-period technology, the firm's initial efficiency is measured by the distance C1/C2, and using the following period technology as reference, it is equivalent to the ratio C1/C3. A similar calculation is made regarding the firm's performance in the following period, so that based on the initial period technology its efficiency is measured as D5/D4, and with the t+1 technology, it is equal to the distance D5/D6. The Malmquist index combines productivity information relative to actual efficiency behavior and best practice frontiers in both periods in order to determine the efficiency change (or productivity growth) between the t and t+1.



$$\text{Malmquist Index} = \left(\frac{D5/D4}{C1/C2} \; \frac{D5/D6}{C1/C3} \right)^{1/2}$$

Figure 2. Output-Oriented Malmquist Index

Appendix C

YEARLY GROWTH RATES FOR
TFP INDEX
FOR 39 ELECTRIC UTILITIES

COMPANY	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	AVG.
POTOMAC ELECTRIC POWER	14.1%	5.5%	-7.2%	-5.4%	-3.6%	3.3%	-8.6%	8.3%	-5.5%	-0.6%	.0%
GULF POWER COMPANY	-0.1%	-8.4%	12.0%	-5.5%	-4.6%	-6.6%	-3.1%	3.5%	3.9%	-11.3%	-2.0%
TAMPA ELECTRIC COMPANY	0.6%	1.1%	3.5%	-7.5%	-5.2%	3.3%	6.2%	0.3%	0.2%	7.6%	1.0%
SAVANNAH ELEC AND PWR CO	-1.7%	-1.5%	1.8%	-12.9%	1.6%	4.8%	0.4%	-9.6%	1.4%	-13.8%	-2.9%
HAWAIIAN ELEC PWR CO	4.0%	2.2%	-0.3%	1.8%	2.9%	0.4%	1.7%	-0.4%	3.0%	-0.1%	1.5%
COMMONWEALTH EDISON	-8.8%	-8.4%	-1.9%	-2.0%	-15.6%	-6.1%	0.9%	-5.7%	-4.4%	-6.2%	-5.8%
INDIANAPOLIS PWR AND LIGHT	-5.5%	-5.1%	3.8%	-1.1%	-6.6%	1.3%	-10.2%	12.8%	1.2%	3.0%	-0.6%
PUB SERV OF INDIANA	1.6%	6.0%	0.4%	-4.7%	2.8%	4.5%	-1.7%	-5.3%	3.3%	-3.3%	0.4%
KANSAS GAS AND ELECTRIC	-6.3%	-5.4%	-2.7%	5.4%	3.5%	-5.8%	10.0%	11.6%	-9.7%	4.6%	0.5%
KENTUCKY POWER COMPANY	6.7%	0.1%	-9.4%	6.0%	-10.2%	13.6%	-6.2%	-5.3%	-6.8%	13.2%	0.2%
KENTUCKY UTILITIES COMPANY	30.5%	-3.4%	4.2%	15.0%	-1.5%	5.3%	2.1%	0.6%	-13.6%	8.3%	4.8%
LOUISIANA PWR AND LIGHT	12.1%	6.3%	0.2%	-4.3%	2.5%	2.1%	-4.9%	-3.2%	-9.9%	-7.4%	-0.6%
DETROIT EDISON COMPANY	-0.7%	-1.8%	1.1%	-0.2%	-3.2%	-4.6%	-0.2%	-1.2%	-2.6%	-6.0%	-1.9%
MISSISSIPPI POWER CO	-6.9%	-7.5%	4.1%	3.1%	-9.6%	1.8%	-14.5%	13.0%	-8.2%	2.1%	-2.3%
MISSISSIPPI PWR AND LIGHT	-3.0%	7.1%	-25.7%	-3.5%	16.4%	15.6%	8.1%	5.0%	-9.7%	1.7%	1.2%
KANSAS CITY PWR AND LIGHT	-0.3%	-2.5%	-3.9%	-11.1%	-5.2%	-3.2%	-6.5%	4.0%	-30.0%	29.4%	-2.9%
UNION ELECTRIC COMPANY	1.8%	.0%	11.5%	-6.5%	10.2%	3.8%	6.4%	-2.2%	-4.3%	-5.0%	1.6%
NEVADA POWER COMPANY	10.8%	-4.1%	-0.7%	8.1%	-2.6%	10.6%	14.5%	-12.6%	0.4%	-1.6%	2.3%
PUB SERV OF NEW HAMPSHIRE	-7.0%	3.2%	-10.1%	-9.4%	2.2%	-2.3%	3.9%	-14.8%	14.6%	-2.1%	-2.2%
PUB SERV OF NEW MEXICO	5.0%	0.1%	-5.4%	2.6%	-0.7%	-16.8%	5.0%	-34.1%	-0.1%	1.1%	-4.3%
OTTER TAIL POWER CO	-8.6%	2.6%	8.6%	-6.3%	14.6%	8.3%	-0.8%	-8.1%	-11.5%	7.8%	0.7%
CLEVELAND ELEC ILLUM CO	8.0%	-1.0%	1.6%	-5.7%	-4.7%	-2.3%	1.4%	-3.5%	-10.2%	-7.1%	-2.4%
COLUMBUS AND SOUTHERN OHIO	1.1%	8.0%	6.2%	-2.8%	-7.8%	4.5%	-1.6%	-6.9%	15.5%	-6.8%	0.9%
OHIO EDISON COMPANY	-6.4%	6.7%	-9.4%	-23.3%	-8.6%	9.0%	-15.4%	10.1%	3.9%	.0%	-2.4%
OKLAHOMA GAS AND ELEC CO	1.0%	4.3%	5.9%	-1.1%	-2.0%	-4.4%	-4.8%	9.4%	-1.6%	0.7%	0.7%
PUB SERV CO OF OKLAHOMA	5.7%	0.2%	-5.6%	6.0%	0.3%	3.3%	-1.5%	-0.2%	-8.4%	4.3%	0.4%
DUQUESNE LIGHT COMPANY	0.9%	2.0%	2.9%	20.9%	-5.2%	5.7%	-1.3%	-17.5%	18.5%	1.2%	2.8%
PENNSYLVANIA PWR AND LIGHT	5.6%	13.7%	10.2%	-4.9%	6.4%	-1.8%	4.7%	-5.5%	-0.4%	-3.4%	2.5%
CENTRAL POWER AND LIGHT	9.2%	-5.1%	0.2%	-4.4%	-4.4%	0.9%	2.5%	4.0%	-3.5%	-3.5%	-0.4%
DALLAS POWER AND LIGHT CO	3.0%	3.4%	0.9%	4.1%	6.3%	4.2%	0.4%	1.2%	2.0%	3.4%	2.9%
EL PASO ELECTRIC CO	0.2%	5.2%	2.5%	0.6%	2.0%	-5.0%	0.3%	-9.5%	6.8%	-10.7%	-0.8%
HOUSTON LIGHTING AND PWR	1.2%	1.5%	-1.5%	-4.1%	-1.6%	1.3%	-2.6%	-3.3%	0.6%	-3.8%	-1.2%
SOUTHWESTERN ELEC PWR CO	0.3%	11.1%	-9.7%	3.3%	-1.3%	-4.0%	0.6%	0.5%	1.2%	-2.2%	.0%
SOUTHWESTERN PUB SERV CO	3.4%	5.2%	-0.9%	1.3%	-3.1%	2.8%	0.1%	-0.9%	-1.4%	5.0%	1.2%
TEXAS ELEC SERV CO	-1.3%	0.6%	-2.1%	5.1%	1.7%	1.6%	-1.3%	5.8%	2.9%	1.0%	1.4%
TEXAS PWR AND LIGHT CO	1.1%	-2.3%	-1.8%	-9.4%	-8.1%	-5.8%	6.0%	-0.8%	-5.8%	1.9%	-2.5%
WEST TEXAS UTILITIES CO	3.0%	5.3%	-2.0%	3.2%	3.9%	1.9%	1.7%	-4.1%	3.0%	7.5%	1.8%
UTAH PWR AND LIGHT CO	-13.4%	21.7%	21.0%	-4.8%	6.9%	-23.8%	31.7%	15.1%	-2.1%	14.6%	6.7%
APPALACHIAN PWR CO	10.5%	26.3%	-3.0%	-11.9%	-9.1%	4.8%	-6.2%	-1.3%	1.7%	1.2%	1.3%
AVERAGE	1.8%	2.4%	0.2%	-1.7%	-1.0%	0.7%	0.4%	-1.3%	-1.7%	0.5%	.0%

Notes

1. The theory of incentive regulation, as derived in Appendix A, deals with the constraints posed by productivity *growth*. The *level* of productivity, as such, is not a focus of the economic concepts that form the basis of incentive regulation.

2. M. Beesley and S. Littlechild, "The Regulation of Privatised Monopolies in the United Kingdom," *The Rand Journal of Economics*, XX, 3 (1989), p. 455; also see M. Armstrong, S. Cowan, and J. Vickers, *Regulatory Reform: Economic Analysis and British Experience* (Cambridge, MA and London: MIT press, 1994), p. 174 for a discussion on the flexibility available to regulators when setting the *X-factor*.

3. That is, (1) changes in industry prices track changes in industry costs and (2) the changes in an individual firm's prices relative to its costs differ from the industry average due to its relative TFP growth.

4. R. Loube, "Price Cap Regulation: Problems and Solutions," *Land Economics*, LXXI, 3 (1995) 288; and P. Navarro, "The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator," *Yale Journal on Regulation*,

XIII, 1, (1996) 128. For further discussions on the importance of the correct price level when setting X see J. Bernstein and D. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," *Journal of Regulatory Economics*, XVI, 1, (July 1999) 9, 11; and I. Vogelsang, "Optimal Price Regulation for Natural and Legal Monopolies," *Economia Mexicana, Nueva Epoca*, VIII, 1 (1999) 31.

5. J. Bernstein and D. Sappington, "How to Determine the X in RPI-X regulation: A User's Guide," *Telecommunications Policy*, XXIV, 1, (2000) 64. For additional discussions on the intention to track efficient costs by X tracking the differences in input price and productivity growth rates between the relevant industry and the economy, see Vogelsang (1999) p. 10, Bernstein and Sappington (2000) page 64, J. Vickers and G. Yarrow, Privatization: *An Economic Analysis* (Cambridge, MA and London: MIT Press, 1989) p. 296; and Loube (1995), pp. 289-290.

6. See: Loube (1995), p. 289.

7. This theoretical presentation, derived in Appendix A, is taken from J.D. Makholm and M. J. Quinn, "Price Cap Plans for Electricity Distribution Companies Using TFP Analysis," NERA Working Paper (October 21, 1997) pp. 36-39.

8. This differential is equal to the difference between the electricity industry and economy-wide TFP growth rates only if the rates of input price growth are the same for the industry and the nation, i.e., if $dw = dw^N$.

9. Adjusted for observed differences between input price growth rates for the industry and the nation.

10. In an influential article, Charles Nelson and Charles Plosser postulate that macroeconomic variables are better characterized as "non-stationary" processes that have no tendency to return to a predetermined path, instead of being regarded as variables that fluctuate around a deterministic trend. See Charles R. Nelson and Charles I. Plosser, "Trends and Random Walks in Macroeconomic Time Series: Some Evidence and Implications," *Journal of Monetary Economics* X (1982), 139-162. Pierre Perron, on the other hand, makes one of the most compelling defenses of the "trend-stationary" model, arguing that the empirical evidence validates this model when one accounts for the existence of trend-breaks due to certain "structural shocks" that have lasting effects See Pierre Perron, "The Great Crash, The Oil Price Shock, and the Unit Root Hypothesis," *Econometrica*, LVII, 6 (1989), 1361-1401. Perron finds that the only shocks with persistent effects are the 1929 Great Crash and the 1973 oil price shock.

11. Törnqvist (a statistician in Finnish government service writing in the 1930s) and Theil (an American econometrician) both investigated the validity of index number techniques. The index number used most widely for TFP studies, which is the geometric mean of the Laspeyres and Paasche indexes described in basic economics textbooks, is named after both.

12. In technical terms, the Törnqvist/Theil index number is "exact" for the flexible homogeneous translog aggregator function. The Index is "exact" in the sense that it can be directly related to the properties of the translog. For further reference, see W. E. Diewert, "Exact and Superlative Index Numbers," *Journal of Econometrics*, IV, 2, (1976), 115-146.

13. D.W. Caves and L.R. Christensen, "Global Properties of Flexible Functional Forms," *American Economic Review*, LXX, (1980) 422-432.

14. M. Dykstra, "How Efficient is Dutch Electricity Generation: Current Research," CPB Report (the Netherlands), 1997/4, pp. 45-47 (http://www.cpb.nl/nl/pub/cpbreeksen/cpbreport/1997_4/s3.pdf)

15. DEA also allows the construction of output-oriented efficiency measures, which we describe later on with regard to the issue of total factor productivity. In this case, the relevant question is, by how much can output quantities be proportionally expanded without altering the input quantities used? Output- and input-oriented measures are equivalent only in those cases in which the technology of production exhibits constant returns to scale.

16. A. Charnes, W.W. Cooper and E. Rhodes, "Measuring the Efficiency of Decision Making Units," *European Journal of Operational Research*, II (1978), 429-444.

17. Ibid., p. 429.

18. Ibid., p. 443.

19. G Federico, "Why are we all alive? The Growth of Agricultural Productivity and its Causes, 1800-2000," European University Institute, paper for the Sixth conference of the European Historical Economics Society, Istanbul, 9-10 September 2005, pp. 4-5.

20. V. Sena, "The Frontier Approach to the Measurement of Productivity and Technical Efficiency," *Economic Issues*, VIII, Part 2 (2003), 90. Sena refers to the DEA model "underlying the Malmquist index" in the sense that the latter index is a specific application of the general "DEA model" approach to measuring distance between a particular observation and the frontier. She does not imply that the DEA model and the Malmquist index are anything more than analogues in this respect.

21. Ibid., p. 83.

22. The data in Appendix C appears in J.D Makholm, "Sources of Total Factor Productivity in the Electric Utility Industry," Doctoral Dissertation, University of Wisconsin/Madison, May 1986 (L.R. Christensen, advisor), Appendix 4A, pp. 88-89. Note that the validity of the argument is not affected by the antiquity of the data.

23. The Uniform System of Accounts has been used by the FERC and its predecessors since 1938, as mandated by Congress.

24. See "Efficiency and Benchmarking Study of the NSW Distribution Businesses," IPART Research Paper No. 13, February 1999.

25. See Dykstra.

26. BNA (2006), 2. *Referenzbericht Anreizregulierung: Generelle sektorale Produktivitätsentwicklung im Rahmen der Anreizregulierung (2nd Reference BNA Report on Incentive Regulation: General sectoral productivity movements in the context of incentive regulation)*, Bundesnetzagentur, Bonn, 26 January 2006.

27. See Dykstra, p. 1.

28. It is observed often enough that such formulation assumptions might not be appropriate in the case of a recently privatized company, with poorly main-

tained infrastructure, whose costs might be expected to fall faster than the "industry." That would be using the term "industry" too widely, however. It would not be practical to expect productivity growth for a newly privatized company to match that exhibited by a mature, investor-owned industry.

29. Note that Z^* can be positive or negative.

30. Recall that input price growth differs from output price growth by the growth in TFP. Only if national productivity growth were zero could a national output price index be a good measure of national input price growth.

THE LINE IN THE SAND
THE SHIFTING BOUNDARY BETWEEN MARKETS AND REGULATION IN NETWORK INDUSTRIES

Sarah Potts Voll and Michael J. King, Editors

NERA ECONOMIC CONSULTING

National Economic Research Associates, Inc.
50 Main Street, 14th floor
White Plains, NY, 10606
www.nera.com

Copyright © 2007 by
National Economic Research Associates, Inc.
All rights reserved.
Except as permitted under the United States Copyright Act
of 1976, no part of this publication may be reproduced or
distributed in any form or by any means, electronic or
mechanical, without the written permission of
National Economic Research Associates, Inc.

Printed in the United States of America.

Sarah Potts Voll and Michael J. King
The Line in the Sand: The Shifting Boundary Between
Markets and Regulation in Network Industries;
edited by Sarah Potts Voll and Michael J. King,
with a foreword by Alfred E. Kahn.
Includes index.
ISBN 978-0-9748788-4-3
1. Economics 2. Regulation 3. Energy
I. Title.

2007932675

Selected Gas Utility X-factors

Company	Location	Scope	Type	Time Period	X-factor
British Columbia Gas	BC, Canada	Distribution	Price	1998-2000	2%, 2%, 3%
Southern California Edison	CA	T&D	Price	1997-2001	1.2%, 14%, 1.6%, 1.6%, 1.6%
San Diego Gas & Electric	CA	Distribution	Price	2000-2002	1.32%, 1.47%. 1.62%
Southern California Gas	CA	T&D	Revenue	1997-2001	1.1%, 1.2%, 1.3%, 1.4%, 1.5%
San Diego Gas & Electric	CA	G,T&D (gas AND electricity)	Revenue	1994-1999	1.50%
PacifiCorp	CA	T&D	Price	1994-1999	1.40%
Boston Gas	MA	Distribution	Price	1996-2001	1.50%
Central Maine Power	ME	Integrated	Price	1995-1999	.5%, 1%, 1%, 1%, 1%
Central Maine Power	ME	Integrated	Price	2002-2007	2%, 2.5%, 2.75%, 2.9%
Bangor Hydro	ME	Integrated	Price	1998-2000	1.20%
Ontario Distribution Companies	Ontario, Canada	Distribution	Price	2000-2002	1.50%
PacifiCorp	OR	Distribution	Revenue	1998-2001	0.30%

Source: Regulatory Research Associates, Commission Orders

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

Nicor Gas Company
Comparable Group
S and V Estimation

	Company	Growth Rate of Common Shares Outstanding (S) 2003 (a)	2004 (b)	2005 (c)	2006 (d)	2007 (e)	Average S [1] (f)	V [2] (g)	S*V (h)=[(f)*(g)]
1	Avista Corp.	0.0000	0.0000	0.0000	0.0807	0.0000	0.0161	0.1717	0.0028
2	MGE Energy	0.0000	0.1118	0.0000	0.0000	0.0000	0.0224	0.4340	0.0097
3	Nicor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4805	0.0000
4	Northwest Nat. Gas	0.0000	0.0621	0.0000	0.0000	0.0000	0.0124	0.4983	0.0062
5	Piedmont Natural Gas	0.0000	0.1391	0.0000	0.0000	0.0000	0.0278	0.5355	0.0149
6	Southwest Gas	0.0000	0.0748	0.0690	0.0620	0.0000	0.0412	0.1816	0.0075
7	Vectren Corp.	0.1116	0.0000	0.0000	0.0000	0.0000	0.0223	0.4444	0.0099
8	Wisconsin Energy	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3913	0.0000

Source: The Value Line Investment Survey, June 13, June 27, and August 13, 2008.

Notes:

[1] Average common shares outstanding growth rate for 2003-2007.

[2] V = (1-(2007 Book Value per Share/Average Stock Price))

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

Nicor Gas Company
Cost of Equity Summary

	With Issuance Costs	Without Issuance Costs
DCF Cost of Capital[2]	10.46%	10.29%
CAPM[3]		
Method 1	13.71%	13.61%
Method 2	10.25%	10.25%
Average CAPM	11.98%	11.93%
Average of DCF and CAPM	**11.22%**	**11.11%**

[1] See: NICOR Gas Exhibit D-1.
[2] See: Exhibit 10.8.
[3] See: Exhibit 10.9.

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

"DECOUPLING" FOR ENERGY DISTRIBUTORS: CHANGING 19TH CENTURY TARIFF STRUCTURES TO ADDRESS 21ST CENTURY ENERGY MARKETS

Jeff D. Makholm, Ph.D.[*]

Synopsis: In 21st century energy markets, energy distribution systems are wrestling with tariff designs left over from the 19th century when gas distributors manufactured their own gas, and electricity distributors generated their own power. For both, profits were "coupled" to the spinning gas and electricity meters that measured their customers' energy consumption. That coupling has prompted two widespread concerns in new energy markets with their distribution-only gas (and in some cases electricity) utilities. First, the rising price of gas has made average gas use fall and spinning meters to slow down, alarming gas distributors who now see a built-in obsolescence in their traditional rate-setting methods. Second, conservationists, for their part, are alarmed that the traditional profit incentive for distributors inherent in the coupling to those spinning meters may hurt wider energy conservation efforts. While issues stem from the traditional design of all energy distributors' tariffs, changing basic tariff design practices in United States regulation is never easy. It is only the gas distributors' "decoupling" efforts that have gathered growing support from both utilities *and* regulators.

I. Introduction 157
II. A Century of Distribution Ratemaking Practice 159
III. A New Type of Billing Problem for Gas Distributors 162
IV. The Interstate Gas Pipelines and SFV 166
V. SFV at the Distributor Level 168
VI. Opposition to Changing Distributor Tariffs 170
VII. Conclusion 172

I. INTRODUCTION

As the price of natural gas continues to rise, pushed upward by its relatively recent role as the premium fuel for generating electricity, gas consumers are doing what we expect of them in a market economy: they are using less. At the same time, given larger homes, more air conditioning, and a greater use of electronic gadgets, electricity customers are using more power per capita than ever. But, as many gas and electricity distributors continue their 19th century

---

[*] Senior Vice President, NERA, Boston, Massachusetts. Dr. Makholm has a Ph.D. in economics from the University of Wisconsin-Madison. He has been affiliated with NERA since 1984 and specializes in the economics of regulated industries in the United States and abroad. This is an expanded version of a paper given at the American Gas Association's Thirtieth Annual Legal Forum in Vail, Colorado, July 16th, 2007. Wayne P. Olson, Alexander Walsh, and Joshua Rogers of National Economic Research Associates, Inc. (NERA) provided research help. Hethie Parmesano of NERA provided helpful comments.

practice of depending on spinning meters to collect the fixed costs of their local pipeline and wires systems, they face issues that did not arise decades ago. For gas distributors, declining customer use makes meters spin more slowly—causing rates to be obsolete as soon as the ink is dry on regulatory orders. For both gas and electricity distributors, tying financial performance to spinning meters is perceived to be a barrier to encouraging energy efficiency in an era of heightened concern with climate change and an increasing focus on energy conservation.

Ratemaking for American utilities has long depended on objective, known, and measurable "test year" costs and quantities—part of the foundation of those companies' reliable regulation and high creditworthiness. Few question the basic soundness of the American ratemaking process that uses such objective cost information and sales quantities. The problem lies in how those costs are collected from most consumers. When utilities' volumes drop off and meters spin more slowly, collecting fixed costs through volumetric pricing with test year quantities will fail to allow companies to recoup those costs. Conversely, anything that can make the meters consistently spin more quickly falls to the distributors' bottom-line profits. Both problems point to a conflict between the structure of costs and the structure of regulated tariffs in a changed energy market. The conflict would appear to be spurring an increase in rate cases by gas distributors to keep up with falling loads—or in any event the incentive to spur increased energy consumption by any distributor whose profits are tied to those spinning meters.

"Decoupling" for energy distributors is a strange term that vaguely refers to that very old link between spinning meters and utility cost collection. It describes the movement in a number of states to change the way distributors collect their costs. It characterizes an inevitable and inescapable problem arising from institutional rigidities in the practice of regulating distributors, combined with the new gas and electricity markets that distributors were so instrumental in creating. It has attracted a good deal of commentary and objection, much of it misplaced. It has also created allies of environmentalists and gas utility managements—a seemingly unexpected coalition.

Decoupling means breaking the link between distribution revenue (not including the gas or electricity) and those spinning meters. That raises a question: Why, if distribution costs have so little to do with how fast the meters spin, do regulators make utilities rely on that uncertain vehicle to collect their costs in the first place? The answer lies in *history* and *institutions*. Both gas and electricity distributors are well over a century old and once had a very different type of business. Also, commissioners are rarely interested in changing what seems to work in favor of new reasoning or methods.

The following parts of this paper describe the origins of the "coupling" of distribution tariffs (Section II), the reason why those practices have posed a new problem for gas distributors in particular (Section III), changes in tariff design for interstate pipelines that illustrate one remedy for those spinning meters (Sections IV and V), and some of the public policy debate surrounding the implementation of "decoupled" distribution tariffs (Section VI). Section VII concludes.

II. A CENTURY OF DISTRIBUTION RATEMAKING PRACTICE

The operation and regulation of investor-owned utilities has a uniquely long history in the United States. In most of the rest of the world, major investor-owned utilities only appeared after the privatization wave of the late 20th century, and their regulatory institutions are new and untested. But, in the United States, the late 19th and early 20th centuries saw the creation of the legal, accounting, and procedural rules that would allow capital to flow into the sector while at the same time protecting the public's interest in fair and reasonable utility rates. With such a long evolutionary history in its regulatory institutions, it should be no surprise that basic changes come slowly in the United States and are hard fought among experienced interest groups. That is true also of the basic character of gas and electricity rates—they are rooted in practices more than a century old.

Gas distribution is the oldest of modern utility services. Gas utilities first provided a product to American consumers in the early 1800s. The Gas Light Company of Baltimore, founded in 1816, was the first gas utility in the United States.[1] It was soon followed by the Boston Gas Light Company in 1822 and the New York Gas Light Company in 1825. These early utilities produced manufactured gas via a number of processes performed on some form of carbon, usually coal. Gas was expensive and generally used only for lighting—coal was the fuel of choice for urban home heating in the northern states. While the original distributor bills were rendered on a "per burner per consumer" basis, the perfection of the wet gas meter led to the institution of volumetric gas sales around 1834.[2] Customers could then be charged according to their usage. Since gas production was the largest expense for early gas utilities, this new system better matched consumer payments with the gas utilities' costs of manufacturing gas.

While natural gas was discovered around the same time, it was more difficult to market to consumers in major cities. Manufactured gas could be sold anywhere that coal could be transported, stored, and processed. Natural gas was very difficult to store in a place near its markets and needed to be transported from its location in the field to the consumer by pipeline. Roughly forty years after the manufactured gas utility industry first arose, the first natural gas transport company was founded in 1858 in Fredonia, New York, where the first natural gas field had been developed a few decades before.[3] From that date onward through the 1930s, when major advances in pipeline welding allowed for its long-distance interstate transportation, natural gas posed an increasing threat to the manufactured gas industry and its coal suppliers.

There was a great deal of rivalry between different sources of fuel in the 1920s and early 1930s (before the Great Depression halted gas pipeline construction until the end of World War II). Gas pipelines at the time were unregulated at the federal level. They pushed into some northern United States

---

1. Gas Light Company of Baltimore was formed in 1816 at the instigation of the famous American portrait painter Rembrandt Peale and a local scientist who had experimented with ways of manufacturing illuminating gas, Dr. Benjamin Kugler. Peale formed an art museum and arranged to light it with Kugler's gas, made from distilling pine tar. *See* AM. GAS ASS'N RATE COMM., GAS RATE FUNDAMENTALS 2 (4th ed. 1987).

2. *Id.*

3. *Id.* at xviii.

cities without any federal certificate in the face of major objections from coal companies that refused to grant gas pipelines rights-of-way into regions of the country considered "coal territory."[4] Coal interests objected to the transition to natural gas on the basis of a number of self-serving grounds. Among other things, the coal interests argued that: (1) natural gas pipelines would displace the skilled labor that was needed in the coal manufacturing plants; (2) natural gas was a luxury commodity; (3) keeping natural gas in the South would foster regional economic development; and (4) while both coal and gas are exhaustible resources, gas reserves were estimated in decades and coal reserves in centuries.[5] Ultimately, none of these various objections of the coal industry halted the advance of natural gas into the coal markets. By the late 1940s and early 1950s, most gas distributors in the United States had switched over to natural gas and retired their manufactured gas facilities.[6]

This switch caused a major change in the gas distribution utility business model. Now that gas was merely purchased by distributors on behalf of customers, the distributors' own costs became largely invariant to the volume of gas sold. Much of consumers' gas costs afterwards became a function of rising natural gas commodity prices and interstate transportation charges—both pass-through expenses of the distributor—leaving the share of the distributors' own costs shrinking as a percentage of the total bill. This was particularly true after 2000 as the price of gas rose sharply, as shown below in Figure 1.[7]

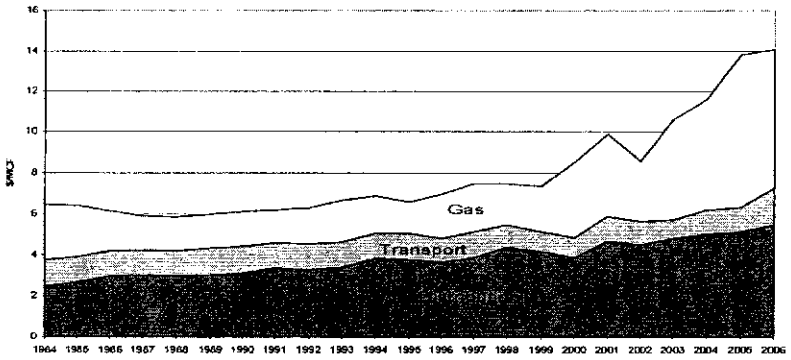


Figure 1: Residential Gas Price Components 1984-2006.[8] *Source: U.S. Energy Information Administration (various issues).*

4. CHRISTOPHER J. CASTANEDA, INVISIBLE FUEL: MANUFACTURED AND NATURAL GAS IN AMERICA, 1800-2000 111 (Twayne Publishers 1999).

5. Ralph K. Huitt, *Federal Regulation of the Users of Natural Gas*, 46 AM. POL. SCI. REV. 455, 455-456 (1952).

6. CASTANEDA, *supra* note 6, at 144.

7. The corresponding components of final electricity prices to customers are not so easy to obtain, and they are highly dependent on the region of the country and whether the electricity companies have been restructured. In general, however, the greater share of costs (perhaps 60%) for delivered electricity is accounted for by generation, with 10% for transmission and 30 for distribution.

8. These figures were derived by taking the differences between final customer prices, city-gate prices, and wellhead prices.

The provision of electricity service to major cities followed gas by some fifty years, although that industry also focused on measuring the energy provided to customers rather than the cost of getting it to them. On September 4, 1882, the first central station electric generating plant was put into operation by the Edison Electric Illuminating Company and supplied electricity for lighting purposes from its Pearl Street location in New York City.[9] Other utilities such as the Chicago Edison companies and numerous municipals followed, taking advantage of the large-scale economies present in electricity generation famously exploited by industry entrepreneur Samuel Insull.[10] This trend towards ever-greater generation, in conjunction with certain early innovations in electricity transmission, brought the electric industry closer to its modern state.[11]

While utility operators were discovering the broader economics of the industry, they also grappled with the problem of measuring the amount of electricity used by customers. Although the first United States patent on electricity measurement was taken out in the 1870s, changes in the end-use of electricity and method of transmission, endemic to the infancy of the industry,[12] posed obstacles to the development of a universal meter. This problem was in large part solved in 1894, with the invention of a commercially viable induction watt-hour meter by Oliver B. Shallenberger.[13] Further evolution of metering devices produced smaller and less expensive devices. These discoveries allowed electric companies to measure the amount of electricity consumed by their customers at increasingly lower costs.

In today's market, with millions of household and small commercial gas and electricity customers to serve, the pricing practices of most distributors are still restricted to the volumetric pricing of the 19th and early 20th century for the simple reason that household and small business meters still only measure the flowing gas and electricity supply. The fundamental tariff equation they use to develop their rates (Equation 1) is as follows:

$$\textit{Distribution Volumetric Rate} = \frac{\textit{Test Year Distribution Cost of Service}}{\textit{Test Year Volumes Distributed}}$$

9. NEIL BALDWIN, EDISON, INVENTING THE CENTURY 137-8 (Hyperion 1995).

10. *See generally,* Hon. Richard D. Cudahy & William D. Henderson, *From Insull to Enron: Corporate (Re)Regulation After the Rise And Fall of Two Energy Icons*, 26 ENERGY L.J. 35, 35-110 (2005).

11. This innovation in electricity transport was made possible through the invention of the alternating current system by Nikola Tesla. It was marketed by George Westinghouse, a purchaser of such inventions. JILL JONNES, EMPIRES OF LIGHT: EDISON, TESLA, WESTINGHOUSE, AND THE RACE TO ELECTRIFY THE WORLD 159-63 (Random House 2003).

12. At its birth, the electric utility business was not nearly as well defined as it is today. The industry struggled with questions such as whether the focus of the business should be on small-scale generators for individual users, or large-scale generators that could serve broad geographic areas, and whether alternating or direct current should be used for electricity transmission. The industry was also unsure if the primary customers of electricity would be city lighting and streetcar services, residential consumers, or industrial consumers, and if the industry would be limited to urban areas due to the costs of transporting electricity.

13. This invention was also known as the "out-of-phase meter." The device employed a small induction motor with the voltage and current coils 90 degrees out of phase with each other.

Actual tariff structures for many United States distributors are merely variants of this basic volumetric rate formula. Actual volumetric tariffs may contain "declining blocks" or other ways to create tariffs that provide for some form of crude volume discount (or "inverted blocks" to mimic crudely a kind of peak-load pricing or to provide a subsidy to low-use consumers).[14] Most distributors also have small monthly distribution service charges. Such practices for distributors are old and idiosyncratic, and the basic rate structures for many have remained generally unchanged for decades. In the gas utility business, they survived not only the conversion to natural gas in the early and mid 20th century, but also the transition to deregulation of gas prices and the creation of contract carriage on the interstate pipeline network in the 1990s. In the electricity utility business, this method of charging most customers survived the demise of integrated utilities in many states and the creation of competitive wholesale generating markets.

III. A NEW TYPE OF BILLING PROBLEM FOR GAS DISTRIBUTORS

The issue of separating distribution charges from spinning meters has arisen before in United States regulation. For example, many gas distributors in the late 1980s and 1990s, led by Brooklyn Union Gas and others, instituted "weather normalization" clauses in order to free their revenue collections from the year-to-year vicissitudes of the weather—the driving force behind how fast the meters spin for those customers that use gas for heating. By the start of 2007, many states had authorized weather normalization clauses, both to economize on the cost of short-term debt in warm winters (as distributors borrow to make up for low warm-weather revenues) and also to save on management wear and tear associated with revenue streams that, while highly stable on a multi-year basis, were less than predictable year-to-year.[15]

These weather normalization clauses, which are a form of decoupling because they separate the link between revenues and weather, stopped being newsworthy in the 1990s. Why is decoupling back in the news? The reason appears in Figure 2.

---

14. An example of a declining block volumetric gas distribution tariff is as follows:

Monthly Consumption (Mcf)	Billed at: (per Mcf)	For a monthly use of 31 Mcf, the bill is computed as follows:							
First 3.0	$ 12.00	First	3.0	@	$ 12.00	per Mcf	=	$	37.50
Next 7.0	$ 10.00	Next	7.0	@	$ 10.00	per Mcf	=	$	70.00
Next 20.0	$ 8.00	Next	20.0	@	$ 8.00	per Mcf	=	$	160.00
All Additional	$ 7.00	Remaining	1.0	@	$ 7.00	per Mcf	=	$	7.00
			31.0		Total Bill			$	274.50
					Average price of gas			$ 8.85/Mcf	

15. For a list of these states, see Cynthia J. Marple, Dir., Rates and Regulatory Affairs, Am. Gas Ass'n, Address at the AGA/EEI 2007 Chief Accounting Officers Conference: Energy Efficiency and Revenue Stability: Compatible Goals (June 26, 2007), at 15, https://www.aga.org/NR/rdonlyres/7F003F22-A9F1-408B-AE1F-970AAD108A77/0/0707MARPLE.PPT.

Rising prices have made energy efficiency a priority among gas consumers, leading to the widespread use of more efficient homes, appliances, machines, and equipment. These changes in consumption patterns underlie the decline in residential gas usage per customer displayed in Figure 2. In electricity, however,

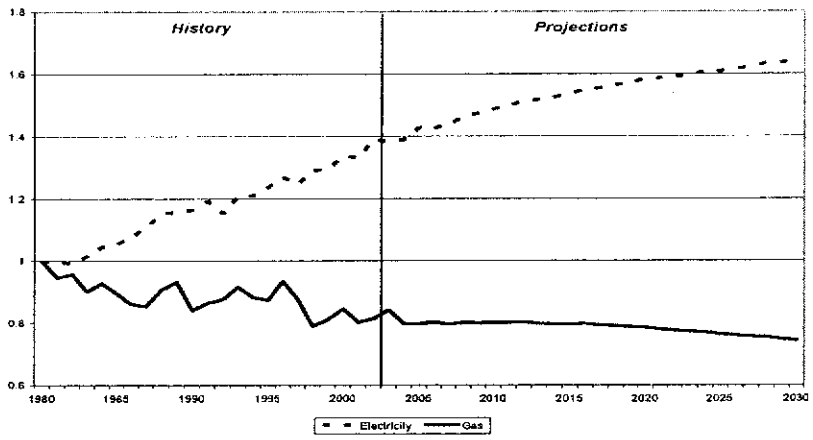


Figure 2: Per Capita Residential Electricity and Gas Consumption 1980-2030 (Index, 1980 = 1). Source: U.S. Energy Information Administration (various issues).

larger homes, more use of air conditioning, and the greater penetration of electronic equipment (including power-hungry plasma TVs) have accounted for a rising level of electricity use per customer.

The price of natural gas has increased dramatically, as illustrated in Figure 3.

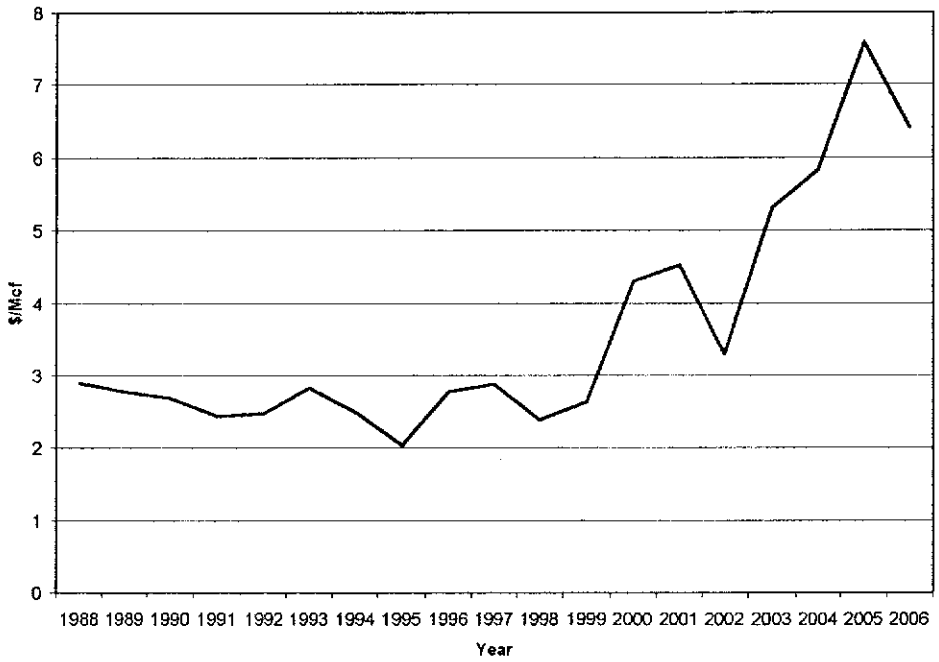


Figure 3: Natural Gas Prices, 1988–2006. Source: U.S. Energy Information Administration (various issues).

The source of this trend in gas prices is growing demand, particularly for power generation. The effect of the technological advances in combined cycle gas turbines (CCGTs) coupled with the new power markets in the United States have caused a large expansion in the construction of such plants as shown below in Figures 4 and 5. Figure 4 shows a representative collection of U-shaped average cost curves for electricity generating plants. It also shows that from 1930 to 1980 the efficient scale of low-cost generating plants dropped steadily as plants grew larger. The graph also reveals that only in the 1990s, with the appearance of CCGTs, could smaller gas plants rival and then beat the cost of the giant plants of the 1970s and 1980s. Figure 5 shows the great spike in CCGT generation capacity from 1999 through 2003. While there has been some levelling of this growth since 2003 as power markets softened, the new gas-fired CCGT plants represent a more than 10-fold increase from levels in the mid-1990s.

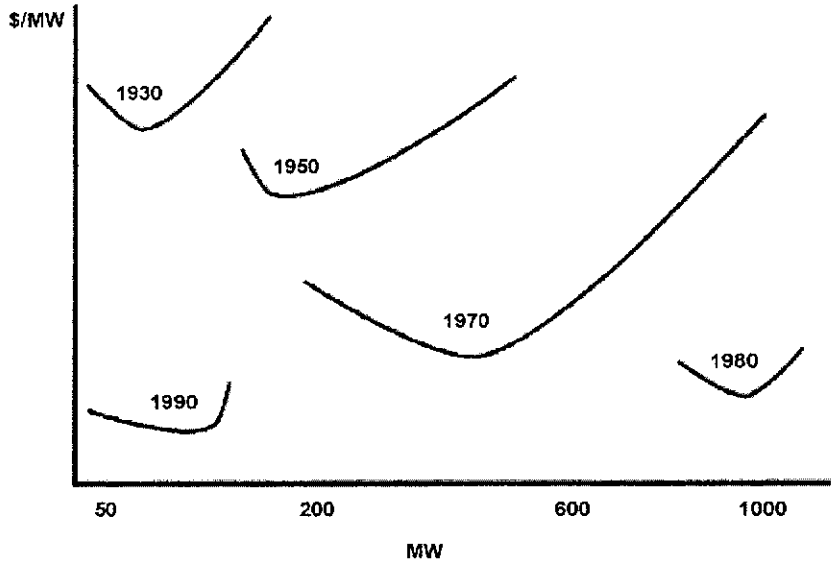


Figure 4: In the 1990s, CCGTs Reversed the Historical Trend Toward Larger Power Plants. Source: SALLY HUNT AND GRAHAM SHUTTLEWORTH, COMPETITION AND CHOICE IN ELECTRICITY 2 (Wiley 1996).

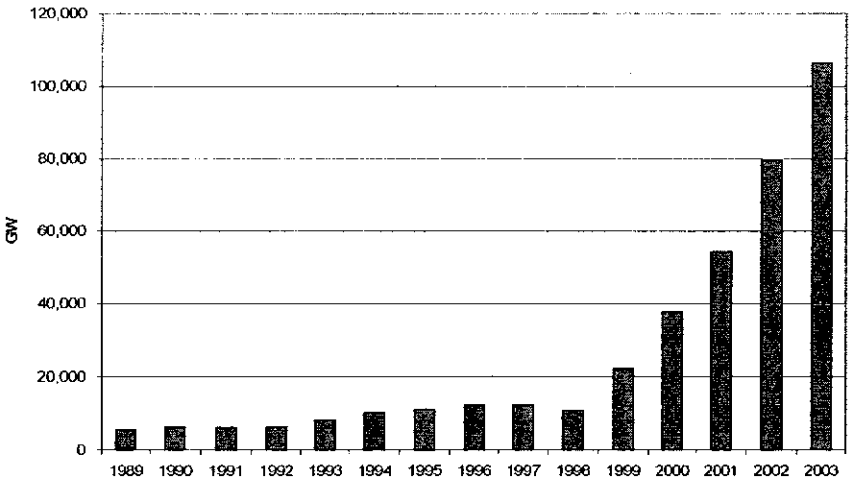


Figure 5: Net United States Capacity Combined Cycle Generation, 1989–2003. Source: NERC Electricity Supply and Demand Database 2004.

Together, these graphs demonstrate the leap in power generation with CCGT technology, as very low cost power accompanied much smaller plants, and how those plants have spurred the demand for gas as a generation fuel.

The use of gas for the new CCGT plants, the consequent rise in gas prices,

and the resulting persistent decline in gas use per customer creates a dilemma for gas distributors that are still burdened with 19th century rate structures.[16] The decline in use per customer leaves distributors with only limited remedies for the problem of outdated test year volumes:

1. remove test year volumes from the denominator of the Equation 1 method and substituting some other billing factor;
2. retain a volumetric rate design but adjust those denominator volumes in Equation 1 over time to keep up with the declining volumes vis-à-vis the test year via an automatic adjustment; or
3. file new rate cases to update Equation 1 with new data.

All three remedies are in evidence in various states.

IV. THE INTERSTATE GAS PIPELINES AND SFV

After a number of revisions in the 1970s and 1980s to the structure of interstate pipeline rates, the FERC settled in the 1990s on the "straight fixed variable" (SFV) method for pipelines to collect their fixed costs. SFV charges operate as a form of "rent" of reserved space on the interstate pipeline network, rendering a regular monthly bill for customers' leased pipeline capacity regardless of how much gas flows. SFV is efficient and now largely uncontroversial at the interstate level.[17] It serves as an effective price signal for the use of assets that do not depend on the pipeline companies' actual volumes shipped.

From the 1950s through the 1980s, however, the regulated price and availability of gas in interstate pipeline transport was highly controversial. The delivery of pipeline-owned gas to the city-gate stations of distributors was central to the pipelines' business.[18] During the period of regulated gas prices, the size of the volumetric portion of the rates for interstate pipelines rose and fell under constant controversy, driven chiefly by considerations pertaining to the price of delivered gas rather than the cost of transportation. Two distinct phases of regulatory oversight marked this period:

- Greater Volumetric Tariff (1942-1973). In the *Seaboard*[19] decision, the Commission directed 50% of fixed costs into the volumetric portion of pipeline tariffs, ostensibly to recognize that pipeline systems were designed to meet both peak and storage-related gas

16. This is the case whether or not the distributors have weather normalization billing mechanisms. Those mechanisms adjust year to year based on weather deviations from average, but cannot deal with lower sales over time due to a demand response to high gas prices.

17. When first mandated in 1992 as part of FERC Order No. 636, SFV shifted pipeline costs among different pipeline users, causing contention among the various winners and losers—as any change in rate design would. Order No. 636, *Pipeline Service Obligations and Revisions Governing Self-Implenting Transportation; and Regulation of Natural Gas Pipelines After Wellhead Decontrol*, [Regs. Preamples 1991-1996] F.E.R.C. STATS. & REGS. ¶ 30,939, 57 Fed. Reg. 20,393 (1992).

18. Under the Natural Gas Act of 1938, interstate pipelines were assumed to be in "the business of transporting and selling natural gas for ultimate distribution to the public . . . ." Natural Gas Act, 15 U.S.C. § 717(a) (2000).

19. *Atl. Seaboard Corp.*, 11 F.P.C. 43 (1952).

sales. With gas shortages for interstate shipments in the early 1970s, pipeline companies had difficulty meeting peak day gas sales obligations. In response to this problem, the Commission in *United*[20] increased the volumetric portion of pipeline tariffs to 75%. The Commission wanted to limit gas use by certain price-sensitive industrial end-users of gas.

- Decrease in Loading (1973-1993). Beginning in the 1970s and continuing through the early 1980s, the Commission recognized the gas market conditions that it used to justify *United* no longer existed—although it believed that some minimal loading would provide pipelines with an incentive to minimize purchased gas costs.[21] Ultimately, the FERC in 1992 removed interstate pipelines from the business of selling gas to distributors at the city gate. The absence of gas sales eliminated the remaining reason to rely on a volumetric rate to collect interstate pipeline costs.

Any type of pipeline charge unrelated to capacity was apt to—and did—skew incentives. The battles over the size of the volumetric portion of the tariff generally had nothing to do with efficiently collecting pipeline costs, as such. They either served to benefit those customers taking at low load factors (who would pay a smaller overall bill compared to those with higher load factors) or would benefit the pipeline company itself (if it could construct the rates on volumes that it expected to beat in practice).

Loading capacity costs into commodity-sensitive tariffs created fights over regulated rates (among sets of customers knowingly dividing cost responsibility in a zero-sum game) and gave pipeline companies inefficient incentives to ship to customers gas supplies from every possible source and hence keep the meters spinning. The pipeline companies' practice of re-selling gas at the overall average cost of gas led many of them to purchase very expensive supplies at the margin under onerous and individually uneconomic terms. These uneconomic gas supplies bought in the 1970s and 1980s contributed to financial problems for many interstate gas pipelines by the 1980s as the older, lower-priced regulated supplies either ran out or were deregulated by the FERC or Congress. The resulting distress of the pipeline companies laid the groundwork for voluntary open access and final interstate pipeline restructuring in the 1990s. That final result, however, was largely an unscripted consequence in a volatile gas market, commodity loading of fixed costs in pipeline tariffs, and the resulting incentive on the part of interstate pipeline companies to find a way to keep those meters spinning once the largely volumetric rates had been set.

Electricity transmission has not seen the history or the extent of fights that led up to SFV rates on interstate gas pipelines. Compared to the interstate gas pipeline network, the electric transmission grid was traditionally a small, state-by-state patchwork affair with independent utilities generating, transmitting, and distributing their own electricity. The issue of efficient transmission tariff

---

20. *United Gas Pipe Line Co.*, 50 F.P.C. 1348 (1973).

21. *Atlantic Seaboard Corp., et al*, 11 FPC 43, 94 PUR (NS) 235 (1952); Opinion No. 249, *Tenn. Gas Pipeline Co., a Division of Tenneco Inc.*, 27 F.E.R.C. ¶ 63,090 at p. 65,373 (1984); *United Gas Pipe Line Co.*, 3 PUR 4th 491 (FPC 1973), *reh'g denied*, 51 FPC 1014 (1974); *Tennessee Gas Pipeline Co., a Division of Tenneco Inc.*, 36 F.E.R.C. ¶ 61,071 at p. 61,163-61,168 (1986).

design and reasonable cost allocation has arisen recently, however, with the rise of wholesale energy markets. From that patchwork of separate transmission businesses, each with its own set of "wheeling" tariffs, a more rational capacity-based set of transmission charges that reflects better the use of wider regional networks has emerged.[22]

V. SFV AT THE DISTRIBUTOR LEVEL

Implementing an SFV-type of decoupling is not as straightforward for gas or electricity distributors as it was for interstate pipelines, for two reasons. First, gas distribution meters do not generally provide information on maximum peak-day usage for the millions of distribution customers.[23] Second, since the 19th century, distributors have never structured their charges to mimic the "rent" charged by interstate pipelines under interstate pipeline capacity contracts. That is, the vast majority of small distribution customers have no limits on their ability to take gas, because gas distribution companies are obligated to serve all comers. Interstate pipelines, by contrast, serve a much more narrowly-defined clientele, composed of customers with contracts that state the levels of deliveries that are assured and the amounts that can be interrupted. Changing from volumetric to fixed charges for distribution service would change the level of many customers' overall charges—some higher, some lower. Such changes are never popular with consumers (particularly with consumers whose bills increase).

Despite the difficulties, a number of commissions appear to be adopting something like SFV rate designs for gas distributors in particular. Georgia's Legislature made SFV the standard in 1997 with Senate Bill 215.[24] Several gas distributors from Oklahoma, Kansas, Michigan, and Missouri either currently offer customers a choice between volume charges and SFV or have filed proposals with their commissions to institute such a policy. In North Dakota, an opinion from a recent Northern States Power Company's rate case identifies significant benefits that will result from adopting a new SFV-type distribution tariff structure: "[t]he new billing format will decrease the price volatility in winter gas bills. It ends unfair rate discrimination against customers living in older homes. And it helps lower the chance that [the Commission] will hear another rate case in the near future."[25]

---

22. In electricity, transmission pricing and cost allocation are still in their early stages as regional transmission networks develop further and adapt to the regional structuring and allocation of transmission charges. Nevertheless, some of the contention between states and utilities in a region appear to have parallels with the issues that arose before open access on the gas transmission system when pipelines operated a pooled gas system for their connected distributors. J.D. Makholm, *Electricity Transmission Cost Allocation: A Throwback to an Earlier Era in Gas Transmission*, 20 ELECTRICITY J. (2007).

23. Some meters do, but only for larger commercial and industrial classes who purchase "transportation" service from distributors.

24. S.B. 215, 97th Leg. (Ga. 1997).

25. Order Adopting Settlement, Northern States Power Company, No. PU-04-578, at 6 (N.D. Pub. Serv. Comm'n June 1,2005) (Commissioner Clark, concurring).

Other states have kept the basic volumetric element of distribution tariff structures intact but have implemented automatic adjustments. Those states are shown below in Figure 6.[26]

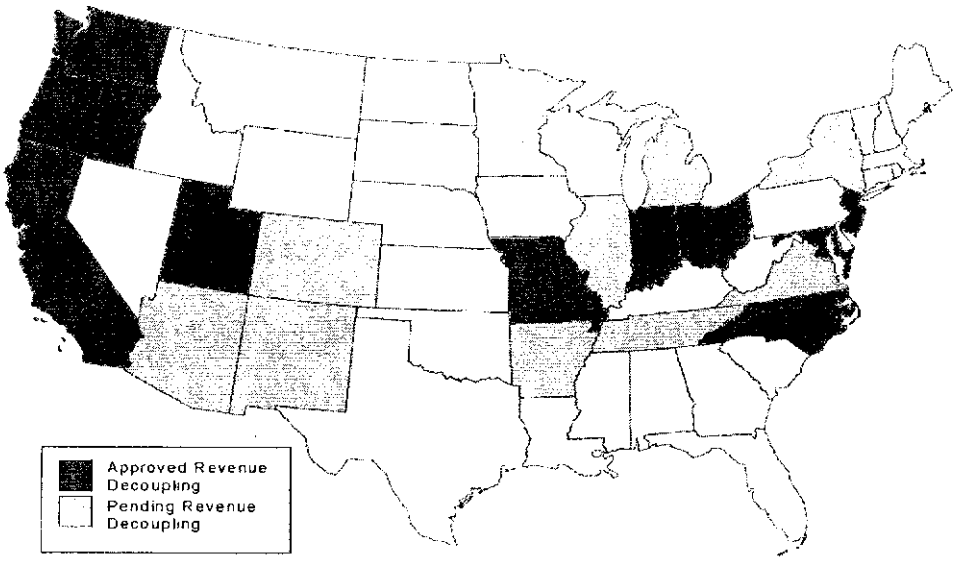


Figure 6: Natural Gas Revenue Decoupling as of April 18, 2007. Source: American Gas Association (2007)

Electricity distributors have not generally faced the imperative of declining use per customer.[27] The impetus for decoupling for electricity distributors has come from those who perceive that the distributors retain the traditional incentives to increase the spinning of those electric meters. The larger point for electricity distributors is that rate cases are disruptive and costly, as are accounting and billing methods to account for changing customer usage patterns.[28] Rising customer usage can offset increasing costs and traditionally contributes to lengthened periods between rate cases. As such, it is to be

26. Electricity and gas distributors have previously pushed for the automatic pass through of various cost items over which they have little control, and which could quickly imperil utility finances (like fuel and purchased gas costs). MICHAEL SCHMIDT, AUTOMATIC ADJUSTMENT CLAUSES: THEORY AND APPLICATION (Mich. State Univ. 1980). Some distributors in the United States have also recently been attempting to extend periodic automatic updates to other cost items, such as rising bad debt expenses and the new information technology expenses required to facilitate new markets. The efficacy of those requests for tracking various costs is outside of the scope of this paper.

27. Some integrated electric utilities are interested in decoupling as one method of dampening the demand for new capacity. Now knowing what the carbon rules are going to be, delaying capacity additions reduces their risk, and also gives them more time to meet renewable portfolio standards in an era where there is not enough renewable energy to go around.

28. In addition to the direct expenses of *ex post* adjustment to tariffs, the inevitable deferrals of cost are themselves traditional sources of risk for distributors—as such deferral accounts are sometimes targeted for less than full cost recovery.

expected that decoupling initiatives aimed at customer usage would hold no inherent allure for electricity distributors. Nevertheless, some perhaps see decoupling as part of an entire package of conservation and energy efficiency that they can pursue at the local level in collaboration with regulators and local interest groups.[29]

VI. OPPOSITION TO CHANGING DISTRIBUTOR TARIFFS

In the United States, rate cases are complex and serve as formal dispute resolution forums. It is not surprising, therefore, that a substantial change in the design of local utility tariffs would attract attention and objection—particularly those tariff designs that have survived for many decades. Such was true in the 1970s, when Wisconsin and New York pursued what was then the novel (but now well accepted) principle of *marginal-cost based pricing.*[30] The idea for such pricing for utilities had arisen by the 1940s, as economists sought more efficient solutions to electricity pricing. Professor Harold Hotelling once and for all set marginal cost as the standard by which economists judge efficient tariffs (in an article called by Professor James Bonbright "one of the most distinguished contributions to rate-making theory in the entire literature of economics").[31] Despite the seemingly self-evident nature of the benefit of marginal-cost based pricing to economists, it would take more than thirty years for commissions to study the subject actively. The practical institutional constraints faced by economists in pursuing efficient regulated prices were best expressed by Professor Emory Troxel, one of the great United States regulatory economists of the 1930s and 1940s and a pioneer in attempting to popularize the concept of marginal-cost based pricing in utility ratemaking. Troxel said of marginal-cost based pricing in 1947:

> Being administrators who like to get jobs done quickly, utility commissioners often want a simple, expedient method of earnings control. But the marginal-cost method is so complex that many regulators cannot quickly understand it or easily use it. Being practical, political-minded [people], the commissioners wish a method that is tested by experience rather than general reasoning. . . . Since these [people] are rarely interested in what they consider odd thinking, nothing short of a general upheaval in utility regulation can drive them to study the idea.[32]

Decoupling is not quite in the same league as marginal-cost based pricing as

---

29. State-mandated electricity distribution decoupling is in place in California and Idaho, and there is much talk of it in other states such as Massachusetts, Connecticut, and New Hampshire. California reintroduced decoupling in 2002, following the passage of legislation in April 2001 (§ 739.10), which directed the CPUC to reinstate its policy of breaking the kWh sales/revenues linkage. For detail on decoupling in Idaho, see Order No. 30267, *In The Matter of The Investigation of Financial Disincentives to Investment in Energy Efficiency by Idaho Power Company*, No. IPC-E-04-15 (Idaho Pub. Utils. Comm'n 2007).

30. Indeed, it was not until 1974 that the Wisconsin Public Service Commission, under Chairman Richard Cudahy, opened a general investigation into the application of marginal-cost based pricing for the electric utilities in that state in a case involving Madison Gas and Electric Company. *See* Richard D. Cudahy, *Rate Redesign Today: The Aftermath of Madison Gas*, PUBLIC UTILITIES FORTNIGHTLY, May 20, 1976, at 15-19. This was one year before Professor Kahn, then Chairman of the New York Public Service Commission, opened a similar marginal-cost based pricing investigation in his own state. "Chairman Kahn" has always lamented to his colleagues, this author among them, that Chairman Cudahy beat him to the punch.

31. Harold Hotelling, *The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates*, 6 ECONOMETRICA 242, 242-269 (1938); James C. Bonbright, *Major Controversies as to the Criteria of Reasonable Public Utility Rates*, 30 AM. ECON. REV. 379, 385 (1941).

32. EMORY TROXEL, ECONOMICS OF PUBLIC UTILITIES 463 (Rinehart Company, Inc. 1947).

a revolution in ratemaking for United States distributors, but it has attracted its own measure of controversy and resistance based on many decades of volumetric distributor pricing. Critics of decoupling claim that it "shifts risks" to ratepayers or that an after-the-fact adjustment of billing determinants constitutes proscribed "retroactive ratemaking," or that it is akin to "taxing consumers for the benefit of protecting utilities from financial harm . . . ."[33] For example, a July 2004 Staff Report from the New York State Public Service Commission criticized decoupling as contributing to the uncertainty in customer bills, increasing the risk that the customers would bear, and as a result freeing distributors from that risk.[34] In June of this year, the Massachusetts Department of Public Utilities opened an investigation to evaluate current rate structures. Within the proposal, the commission explicitly acknowledged a potential challenge in dealing with the issue of risk, allowing that the institution of decoupling "could materially alter the distribution of risks among the company, its shareholders, and its customers."[35] Some Commissions (such as New York and Maryland) have made explicit downward risk adjustments to the allowed rate of return to account for this presumed lessening of "risk."[36]

The arguments about risk generally proceed from a colloquial, rather than precise terminology.[37] The cost of capital in the market is widely held to be driven by investors' perception of business and financial risk. These two well-defined types of risk are not affected by decoupling, as such. Weather-related decoupling for gas distributors deals with revenue deviations from a stable and predictable average. It is less costly for distributors, both in terms of short-term borrowing costs and management time, not to have distribution revenue tied to those deviations.[38] The conservation-related decline in average gas customer use is a known, but recent, trend. When combined with a volumetric distribution

---

33. To see the review of such positions see Ken Costello, *Natural-Gas Revenue Decoupling: Good for the Utility or for Consumers?*, PUBLIC UTILITIES FORTNIGHTLY, Apr. 2007, at 46-48.

34. Staff Report, *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*, Case 03-E-0640, at 7-9 (N.Y. Pub. Serv. Comm'n July 9, 2004). The Commission has since deemed revenue decoupling mechanisms a necessary part of their regulatory policies. *See* Order Requiring Proposals for Revenue Decoupling Mechanisms, *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation* and *In the Matter of the Investigation of Potential Gas Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*, Nos. 03-E-0640, 06-G-0746 (N.Y. Pub. Serv. Comm'n April 20, 2007).

35. Vote and Order Opening Investigation, *Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources*, No. D.P.U. 07-50, at 17 (Mass. Dep't of Pub. Util. June 22, 2007).

36. *See* Order No. 81518, *In the Matter of the Application of Delmarva Power and Light Company for Authority to Revise its Rates and Charges for Electric Service and for Certain Rate Design Changes*, No. 9093 (Maryland Pub. Serv. Comm'n July 19, 2007); and Order Establishing Rates for Gas Service, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service*, No. 07-G-0141 (N.Y. Pub. Serv. Comm'n December 21, 2007).

37. There is nothing unusual about using imprecise language in contested ratemaking proceedings, and it happens often enough. *See* Jeff D. Makholm, *The Risk Sharing Strawman*, PUBLIC UTILITIES FORTNIGHTLY, July 7, 1988, at 24-29. In that 1988 paper, I provided a listing of twenty-one different cases involving prudence, excess capacity, rate design, and fuel and gas cost adjustments where the term "risk sharing" had, through imprecise language pertaining to risk, confused rather than crystallized the regulatory issues at stake.

38. For healthy gas utilities, the short-term borrowing needs related to a lack of weather-normalization decoupling appear to have no discernable effect on credit ratings.

rate design, this trend produces a known, but novel, shortfall. There are various ways to deal with the anticipated shortfall, with perhaps the most expensive for consumers being the triggering of rate cases.

In neither case does lessening the reliance by gas distributors on the volumetric tariff affect what is generally understood as the "regulatory compact"[39] between utilities and their customers—nor does it lessen materially the business or financial risk for which investors require compensation.

VII. CONCLUSION

While decoupling for energy distributors could be a non-controversial issue, nothing involving a basic change in tariff design practices is simple in United States regulation. The institutions upon which United States regulatory practices rest are decades old, and for the most part they permit the economical financing of utilities and the protection of consumers under a well known regulatory compact. Administratively, "what works," in our system of regulation, is hard to wipe away with new methods and new reasoning.[40]

For gas distributors, the 19th century tariff structures were reasonably suitable until the 1990s. But with new energy markets, and a new technology for using gas for electricity production, those old tariff structures are showing their age. Distributors have growing incentives to avoid the adverse effects of these 19th century rates, and new tariff structures are appearing in many jurisdictions to replace them. This trend has the potential to reduce the frequency of rate cases. It is likely that the trend—an efficient one for gas distributors in particular—will spread.

Decoupling for electricity distributors appears to be motivated mainly by a public interest desire to remove whatever incentives may exist for distributors to promote sales of electricity between rate cases. In the context of ratemaking only, electricity distributors would see any growth in customer volumes compared to test year levels as a traditional way to countervail rising costs. Decoupling in this context, which would entail administrative costs, rate changes, and the loss of benefits associated with electric meters spinning more quickly as the average customer uses more electricity, would not be inherently attractive to distributors. However, they may accept the initiative as part of a larger package of state-sanctioned public interest initiatives (like subsidized conservation programs). But the spur to pursue decoupling for these electricity distributors is different, and less fundamentally pressing, than for their gas distributor cousins.

---

39. The compact in general terms is as follows: First, in return for a monopoly franchise, utilities accept an obligation to serve all comers. Second, in return for agreeing to commit capital to the business, utilities are assured a fair opportunity to earn a reasonable return on that capital. Irwin M. Stelzer, *The Utilities of the 1990s*, WALL ST. J., Jan. 7, 1987, at 20.

40. Justice Oliver Wendell Holmes said in his treatise on the law: "Most of the things we do, we do for no better reason than that our fathers have done them or that our neighbors do them . . . ." MARTIN G. GLAESER, OUTLINES OF PUBLIC UTILITY ECONOMICS vi (The Macmillan Co. 1927) (quoting OLIVER WENDELL HOLMES, THE PATH OF THE LAW).

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Northern Illinois Gas Company d/b/a Nicor Gas Company	))	
	)	Docket No. 08-0363
Proposed general increase in rates, and revisions to other terms and conditions of service	)))	

AFFIDAVIT

I, Jeff D. Makholm, Ph.D. under oath, hereby swear to the following:

1. I am the Senior Vice President of National Economic Research Associates, Inc.;

2. I prepared prefiled Rebuttal Testimony on behalf of Northern Illinois Gas Company, d/b/a Nicor Gas Company, submitted as Nicor Gas Ex. 25.0, including Exhibits 25.1 through 25.17, and filed on September 25, 2008;

3. An Errata to my Rebuttal Testimony was filed on November 18, 2008 to provide for corrections discovered after September 25, 2008.

4. The answers set forth in my Rebuttal Testimony are to the best of my knowledge, true and correct; and

5. If asked those same questions today, my answers would be the same.

Jeff D. Makholm, Ph.D

Subscribed and sworn to before me
this 18th day of November, 2008.

Notary Public

Silvia E. Santos
Notary Public
Commonwealth of Massachusetts
My Commission Expires
September 22, 2011