Working Paper 8509

TOTAL FACTOR PRODUCTIVITY AND ELECTRIC UTILITIES REGULATION

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The author would like to thank Amy Durrell, who provided valuable research assistance.

December 1985
Federal Reserve Bank of Cleveland

Introduction

Regulators base electricity prices or rates on the average operating cost of producing electricity and on a "fair" rate of return on capital for a given year[1].

There are two shortcomings with this procedure. First, it does not consider the dynamics of average total costs and its components. Regulations may influence the incentives of utilities to innovate and overcapitalize as well as the demand for electricity which, in turn, may influence utility operating costs.

Second, regulators consider only tangible input factors (capital, labor, fuel, material) in the calculation of average costs. Intangible input factors (workers' discipline, managerial skills, returns to scale, for example) are not considered in the regulatory price mechanism because they have no explicit and measurable prices and their effect on utility output and costs is difficult to measure.

Nevertheless, the impact of intangible factors on costs and utility profits may be substantial. Moreover, the inability to bring intangible input factors into the rate-setting process may create the <u>wrong</u> <u>incentives</u> for a utility to operate in the most socially efficient way.

One solution to these problems is to examine the components of total factor productivity (TFP). These components include the individual input productivities, a returns to scale effect, and an average cost (AC) shift term. The individual input productivities are the tangible input contributions, the returns to scale term identifies one of the intangible factors, and the AC shift term includes the other intangible effects. Using this decomposition, regulators may obtain a better idea about the sources of AC change.

To measure TFP, economists traditionally utilize the long-run price of capital services. This paper argues that for the purpose of regulation, the shadow rent on capital, which is the short-run measure of the value of capital services, is more appropriate. This is not a new concept -- regulators have used the shadow capital rent measure for decades, but its use with the TFP calculations, which have traditionally employed a long-run capital rent measure, is new. An understanding of the difference between the two notions of capital rent helps to distinguish a short-run shift in average costs from a long-run shift.

In the second part of this paper, the regulatory process is briefly described and the usefulness of TFP indicators to regulators is discussed. TFP and return-to-scale effects are estimated for seven major Ohio "utilities (which produce about 90 percent of the electricity for the state) over the 1964-82 period. The data and their sources are described in Appendix III.

The theoretical discussion of the short run average cost (AC) shift 'is presented in the third section of this paper. It is argued in the fourth section that during times when rate hearings are held frequently, a utility's incentive for productivity increases may decline.

The Regulatory Process

A utility's accounting profit, which is the primary concern of the Public Utility Commission of Ohio (PUCO), is calculated as:

$\pi = R - OC$

where R is operating revenue and OC is the operating cost . Whenever a rate change is requested, PUCO calculates the utility's "fair" return on capital as:

$\pi_r = B \cdot r$

where r is the "fair" rate of return and B is the rate base or the book value of net capital.

The difference between the accounting profit, π, and the fair profit, π_r, is the basic reason for the rate change; electricity rates are set by the regulator to equate π with π_r on the date the hearing is held. As time passes, π may deviate from π_r if input prices, electricity demand, and other factors change, but a rate change to re-equate π with π_r is not made until the next rate hearing. A utility requests a price change hearing when it is convinced that its profit, π is smaller than π_r. If PUCO establishes that π exceeds a reasonable return on capital, say sB, then PUCO calls for a rate decrease hearing. Such hearing is usually prompted by consumer advocates, when $\pi \geq sB$ is observed. This regulatory price adjustment mechanism can be described as

$$P = \begin{cases} P_0 & \text{if } \pi_r < \pi < sB \text{ (no rate change)} \\ P_0 < P_1 \leq P_0 \bullet 1.2 & \text{if } \pi < \pi_r \text{ (rate increase hearing)'} \\ P_2 < P_0 & \text{if } \pi > sB \text{ (rate decrease hearing).} \end{cases}$$

Due to the passive nature of the regulatory process, the last constraint is observed very rarely. This issue is addressed later in the text. The rate increase hearing is the most common one. In this case, electricity price increases from P_0 to P_1.

At first blush, this rate-setting scheme appears sensible. It seems ,reasonably efficient to allow utilities to pass along operating costs. However, there are potentially serious problems related to consumer reactions to rate increases and to the types of incentives given to utilities. First, rate increases may lower the consumption of electricity, which may reduce π below π_r and trigger a rate increase, which in turn may lower consumption and trigger another rate increase and so on. That is, the proper response to falling utility profits because of lower demand may not be to raise rates. Second, utilities may be able to effect rate increases by overcapitalizing, which affects their rate base B. Indeed, rate increases lower the risk of capital investment below the risk level of nonregulated industries, clearly giving utilities the incentive to overcapitalize. Finally, the ability to obtain rate increases because of operating cost increases originating from productivity declines suggests that utilities may not have the incentive to raise productivity.

Thus, not all AC increases should be treated equally. Increases in AC due to input price increases and to environmental regulation, for example, should be passed on, while increases due to inefficient capital investment decisions and increases that may lead to a long-run decline in utility revenues should not be passed on to consumers. It should be clear that it is important to be able to distinguish among the causes of AC change. In the following two parts of the paper, a set of measures that explains the cost change as a weighted sum of different economic factors, based on a TFP approach, is provided.

A Simple Total Factor Productivity Measure for Ohio Electric Utilities

We begin the discussion by relating AC to operating revenue. Operating revenue includes net income and operating costs:

(1) $R = B \cdot r_K + L \cdot r_L + F \cdot r_E + M \cdot r_M$, where

r_K is the rate of return on capital, computed as $r_K = \pi/B$ with π calculated as a residual between OC, and R

L, E, and M are the number of employees, fuel (energy) consumption in physical units, and material, computed as M = (material expense)/r_M, respectively used in the production of electricity.

r_L, r_E, and r_M are the average prices or wage rates for the corresponding inputs.

When r_k in (1) is equal to the fair rate of return on capital, revenue is equal to cost and π equals π_r from the regulator's point of view. In addition, the price of electricity is equal to total average cost, a condition we will maintain in this part of the paper. Later, this assumption is relaxed by taking into account the deviation of r_k from the fair return and the deviation of the fair return from the long-run cost of capital.

Changes in average costs can be decomposed into changes in input factor costs and changes in TFP. According to Kendrick (1973), p. 32, "The TFP ratio indicates the relationship between real product in a given year to the real product that would have been produced (real factor cost) if the productive efficiency of the factors had been the same in the given year as in the base year." The TFP ratio is: $A=Q/Q_c$, where Q is real output and Q_c is real factor cost in the base year. Taking the time derivative of the above equation and dividing it by A, one derives: $A^\circ=Q^\circ-Q_c^\circ$. Where $(\cdot^\circ)$ indicates proportional rate of change. The discrete form of Q_c° is measured by the Tornquist approximation:[3]

(2) $Q_c^\circ=\sum s_i i^\circ$

where s_i is the cost share in the base year of the i-th input and i is the amount of the tangible input factor employed, such as capital (K), labor (L), energy (E) and material (M). Substituting (2) into (1), the TFP rate of change is measured as a residual growth of output that cannot be explained by the growth of tangible inputs:

(3) $A^\circ = Q^\circ-\sum s_i i^\circ$

This TFP measure ignores the impact of the intangible input factors. A better TFP measure can be derived by eliminating one of these intangible factors, the returns-to-scale effect from A°in (3), leaving a new residual denoted as D° as the new TFP measure. This decomposition of TFP can best be demonstrated with the use of a cost function following Gollop and Roberts (1981). Let the cost function be:

(4) $C = G\ (r_L,\ r_K,\ r_E,\ r_M,\ Q,\ T)$

where G is the minimal cost function for each electric utility. A utility maximizes profit by optimizing the choice of input factors. Differentiating (4) in respect to time one derives:

$$(5)\quad \frac{dC}{dt} = \sum_i \frac{\partial G}{\partial r_i}\frac{dr_i}{dt} + \frac{\partial G}{\partial Q}\frac{dQ}{dt} - \frac{\partial G}{\partial t}$$

where i = K, L, E and M. According to Sheppard's lemma for a cost minimizing firm $(\partial G/\partial r_i) = i$, where i is input factor. Applying Sheppard's lemma to (5), one derives:

$$\frac{1}{C}\frac{dC}{dt} = \sum_i \frac{r_i}{C}\frac{i}{r_i}\frac{dr_i}{dt} + \frac{\partial G}{\partial Q}\frac{Q}{CQ}\frac{dQ}{dt} - \frac{\partial G}{\partial t}\frac{1}{C}$$

then:

$$(6)\quad C^\circ = \sum_i s_i r^\circ_i + E_{CQ}Q^\circ + D^\circ$$

where $E_{CQ} = \frac{\partial G}{\partial Q}\frac{Q}{C}$ is the elasticity of cost with respect to output, and

$D^\circ = -\frac{\partial G}{\partial t}\frac{1}{C}$ is the proportionate shift of the cost function over time.

Using the expression for total cost, we can define the dynamic relationship between average cost and its components. Since $AC=C/Q$, $AC^\circ=C^\circ-Q^\circ$, then according to (6):

$$(7)\quad AC^\circ = \sum_i s_i r^\circ_i + D^\circ + (E_{CQ} - 1)Q^\circ$$

The change in average cost, holding input factor prices fixed, is due to two factors: D°, which is a dynamic source of economic growth and $(E_{CQ} - 1)Q^\circ$, which is a static source of economic growth or scale effect. If $E_{CQ} < 1$, then average cost will decline with the rise of output. If $E_{CQ} > 1$, average cost will increase. In the case of constant returns to scale, $E_{CQ} = 1$, average cost is not affected by the change in output. Equation (7) can be directly related to TFP, derived from equation (3).

To illustrate the relationship between the change in cost and the change in the production function, we proceed as follows. Totally differentiating the cost accounting identity with respect to time, one derives:

$$\frac{dC}{dt} = \Sigma\, r_i \bullet \frac{di}{dt} + i \bullet \frac{dr_i}{dt} \quad \text{,then}$$

$$C^\circ = \Sigma \frac{r_i \bullet i}{C} \bullet i^\circ + \Sigma \frac{r_i \bullet i}{C}\, r_i^\circ \text{, or}$$

$$C^\circ = \Sigma s_i\, i^\circ + \Sigma s_i r_i^\circ$$

Then the proportional change in average cost is:

$$AC^\circ = C^\circ - Q^\circ = (\Sigma s_i \bullet i^\circ - Q^\circ) + \Sigma s_i r_i^\circ$$

The change in TFP is a difference between output growth and a divisia index of input growth (see equation (3)), therefore:

(8) $-A^\circ = AC^\circ - C s_i r^\circ$,

substituting (7) into (8) and changing sign

(9) $A^\circ = (1 - E_{CQ})Q^\circ - D^\circ$

Equation 9 shows that the TFP measure in (2) has a returns-to-scale bias.

The sources of economic growth of the seven major Ohio utilities are quantified in the dual (cost) form." An estimate of D can be made by using an estimate of E_{CQ} calculated by Gollop and Roberts (1981). They found that E_{CQ} varied between 0.7 and 0.9 in their sample of electric utilities which included four of the seven major Ohio utilities. For the following calculations, we use a value of 0.8 for E_{CQ}. We first discuss the components of the change in AC over time. Four distinct periods of electricity price and consumption behavior over the 1964-1982 interval were observed. Within each period, the direction of prices (AC) and sales of electricity changes were the same for each utility in the sample. These four subperiods are 1964-1968, 1969-1973, 1974-1979 and 1980-1982. Price and total sales figures for all seven utilities are plotted in chart 1.

In the first period, 1964-1968, the average price of electricity was falling and sales were rising. In the second and third periods, 1969-1973 and 1974-1979, electricity consumption increased but prices also increased. In 1969-1973 period, the increase in sales was greater than in the previous period, but in 1974-1979 period electricity consumption fell considerably. Finally, in the third period, 1980-1982, electricity consumption declined for the first time in Ohio's history and prices increased at the faster rate than in the previous periods.

The sources of this behavior can be identified by decomposing AC into the contributions made by price changes of tangible inputs, by the returns-to-scale effect, and by the shift of the cost curve over time using (7). This is shown in table 1. In the 1964-1968 period, the scale effect and D° indicator of TFP were the major contributors to the decline of AC. Without these effects, the tangible input price changes would have raised AC by 1.5 percent, instead of the observed decline of 1.5 percent. In the 1969-1973 period, the continuing increase of sales of electricity lowered AC by 1.2 percent from the returns-to-scale effect. D° also reversed its effect from the previous period, raising AC by 1.2 percent. In the 1974-1979 period, the scale effect on AC was less than a percentage point

ELECTRICITY: PRICES AND QUANTITY SOLD

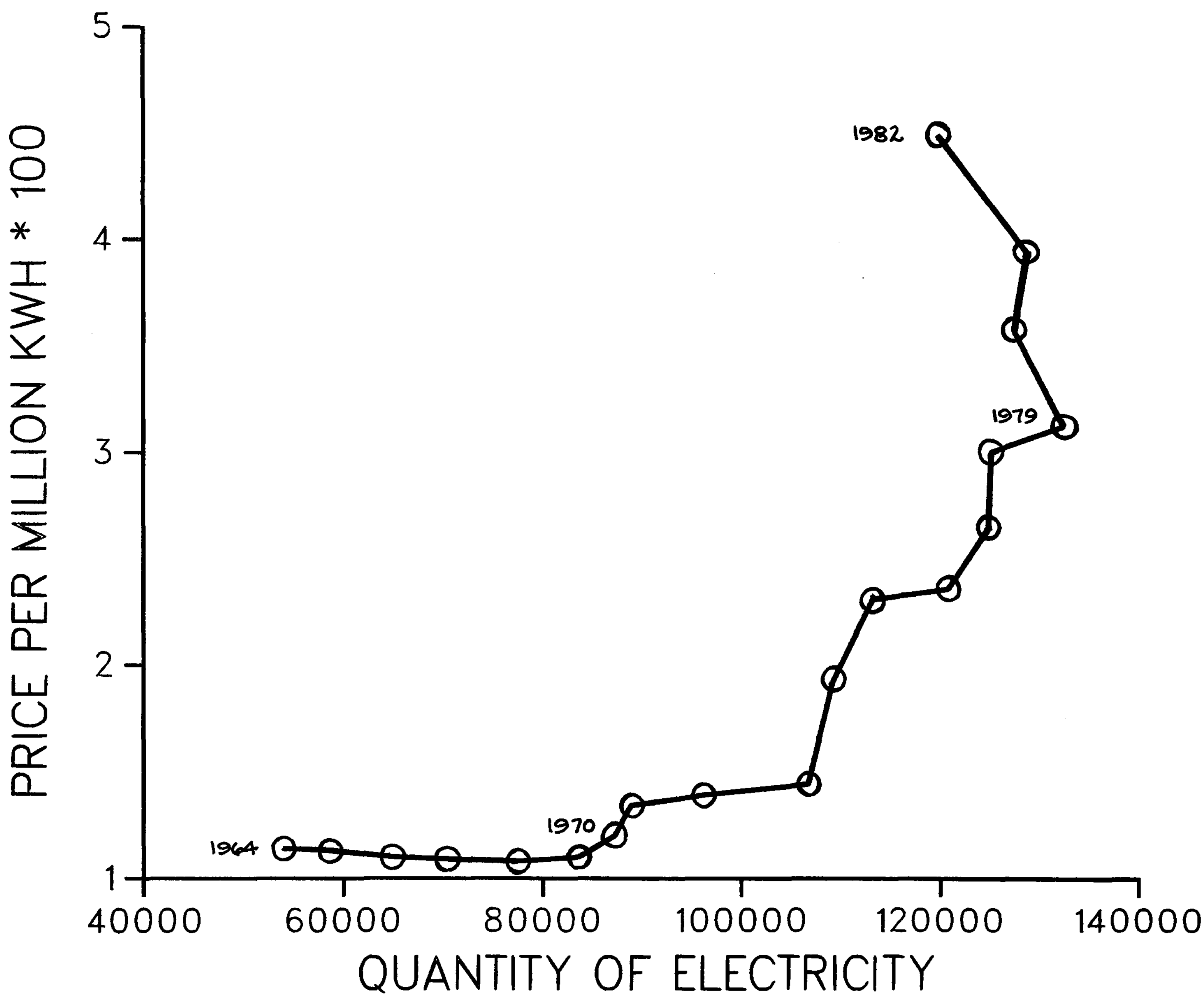


Table 1 Sources of Change of AC for Ohio Utilities

		Average Annual Rates for the Period			
		1964-68	1969-73	1974-79	1980-82
Change in average cost	AC°	-0.015	0.057	0.130	0.120
AC curve shift	D°	-0.012	0.012	0.029	0.036
Return to scale effect	$(E_{CQ}-1)Q^{\circ}$	-0.018	-0.028	-0.007	0.007
Input price effect of capital	$s_K \cdot r_K^{\circ}$	-0.002	-0.005	-0.000	0.004
Input price effect of labor	$s_L \cdot r_L^{\circ}$	0.005	0.010	0.008	0.010
Input price effect of energy	$s_E \cdot r_e^{\circ}$	0.000	0.034	0.076	0.041
Input price effect of material	$s_M \cdot r_M^{\circ}$	0.011	0.018	0.025	0.022

and D° raised AC by 2.9 percent. Finally, in the 1980-1982 period, consumption of electricity declined, forcing utilities away from the optimal scale of production and increasing AC by .07 percent and D° increased its contribution to the AC increase by 3.6 percent.

The impact of other intangible factors on AC was negative in the first period ($D^{\circ}<0$). This was possibly due to improvements in earlier-installed technologies and to the introduction of more efficient generators.. In later periods, fewer new generators were installed, causing a slowdown in the decline of AC. In the 1970s, most Ohio utilities were building nuclear plants, which possibly limited resources for the improvement of utilized facilities. This possibility, plus tighter regulations on air quality may have caused either the decline of TFP ($D^{\circ}>0$) or the increase in AC.

Capacity Utilization, Regulatory Lag, and a SRAC shift.

In this section D^o is decomposed further into a capacity utilization effect and a regulatory lag effect. The regulatory lag arises because rate requests are made only after costs have changed enough to warrant a rate increase. Thus, regulatory lag, through capital rents and revenues, affects both AC and TFP estimates. In the previous section, TFP was calculated using the long-run assumption of cost and revenue equality. This assumption holds if the utility pays the long-run price, P^k, of capital. It can be measured using the Christensen-Jorgenson (1969) rental price index, but because the price of capital is set by the regulator as the fair rate of return on capital, it may not be equal to the long-run price of capital P^k. Thus, our estimates of AC and TFP will be incorrect if P^k does not equal the fair rate of return. Interestingly, it turns out that these capital price discrepancies reflect economic measures of capacity utilization. A detailed explanation of this phenomenon, provided by Berndt and Fuss(1982), is presented below.

The key notion in the Berndt-Fuss approach is the firm's capacity level of output. The capacity level of output Q^* is characterized by the tangential point of the long-run average cost (LRAC) curve and the short-run average cost (SRAC) curve.[5] If the output price is higher than the LRAC at point Q^*, the firm will operate in the region $Q^*<Q$ in order to maximize profits. In this case, the company overutilizes its quasi-fixed capital. If the price of the output is lower than the LRAC at point Q^*, then the firm will operate at the level $Q<Q^*$ in order to minimize losses. This will lead to the underutilization of quasi-fixed capital. Capacity utilization, according to

Berndt and Fuss, can then be measured by $q = (Z^k / P^k)$, where Z^k is the expected shadow rental price of capital. Thus the problem of measuring capacity utilization becomes one of measuring the shadow price of capital. As Berndt and Fuss(1982,p. 28) argue "...the <u>value</u> of services from stocks of the quasi-fixed inputs should be altered rather than their <u>quantity</u>." At the output level Q*, the shadow price of capital is equal to the long-run price of capital, $Z^k=P^k$, and therefore, $q=1$. Nevertheless, if the firm increases its output above Q*, additional units of capital would increase SRAC, meaning that the firm overutilizes its capital and therefore is willing to pay more for its quasi-fixed capital than the market price, $Z^k>P^k$, and $q>1$.

To make this theory operational, operationalize this theory, one needs a measure for the capital rent, Z^k. Hulten (1983) argues that the residual income accounted as a difference between revenue and variable cost per unit of capital is an estimate of Z^k, which is the payment for a unit of capital at time t.

$$Z^{k(t)} = \frac{P(t) \cdot Q(t) - \Sigma r_i(t) \cdot i(t)}{K(t)}, \quad \text{where } i = L,E,M$$

In the short run, the firm minimizes restricted variable costs conditional on variable factors prices, the amount of quasi-fixed capital, and output:

$$(10) \qquad S(t) = s[r_i(t), K(t), Q(t), T] = P^k(t)K(t) + \Sigma r_i(t)\, i(t)$$

where $i = L, E, M$, and $P^k(t)$ is a "long-run" rent per unit of capital stock (the t parameter is omitted in the following for convenience). P^k, as opposed to Z^k, is the opportunity rent for the alternative use of the capital stock. In the case of nonconstant returns, the equality $P^k = Z^k$

would be attained at the level of output where the LR cost is tangential to the SR cost, which is not necessarily the minimum point of short-run costs (see Morrison and Berndt). The difference between P^k and Z^k helps to formulate the relationship between short- and long-run average cost. To represent this relationship, we follow the Hulten approach with some modification.

First, we derive a shift in the SRAC curve. For that purpose, we need to define the partial derivative of the restricted variable cost with respect to capital:

(11) $$\frac{\partial S}{\partial K} = P^k - Z^k.$$

The derivation of equation (11) is presented in Appendix I. A similar equation was derived by Hulten for only one variable component. In a short-run equilibrium, marginal cost equals price: $(\partial S/\partial Q) = P$, and logarithmically differentiating (10), we find (the derivation is similar to that of (6) and presented in Appendix II):

(12) $$S^\circ = \left(\frac{P^k K}{S} - \frac{Z^k K}{S}\right)K^\circ + \Sigma \frac{r_i \underline{i}}{S} r^\circ_i - \frac{\partial s/\partial t}{S} + \frac{PQ}{S} Q^\circ$$

The only term left undefined in (12) is $\frac{\partial s/\partial t}{S}$. It can be expressed as a function of the TFP change A°, having all input factors fixed ($\underline{i}$):

$$\frac{\partial s/\partial t}{S} = \frac{\partial S}{\partial t}\frac{1}{S} = \frac{\partial S}{\partial Q}\frac{dQ}{dt}\frac{1}{S}\bigg|_{\underline{i}} = \frac{PQ}{S}\frac{dQ/dt}{Q}\bigg|_{\underline{i}} = \frac{PQ}{S}A^\circ$$

Denote SRAC as $\sigma = S/Q$. Then $a^\circ = S^\circ - Q^\circ$. To derive the shift of the SRAC, we assume input prices are constant in (12), (this defines shift of the <u>real</u>

SRAC), then

$$\sigma^{\circ} = \frac{P^k K - Z^k K}{S} \bullet K^{\circ} - \frac{PQ}{S} \bullet A^{\circ} + \frac{PQ}{S} \bullet Q^{\circ} - Q^{\circ},$$

where

$$P^k K - Z^k K = (P^k - \frac{PQ - \Sigma r^i i}{K})K = P^k K + \sum_{i \leq k} r^i i - PQ$$

$$= S - PQ,$$

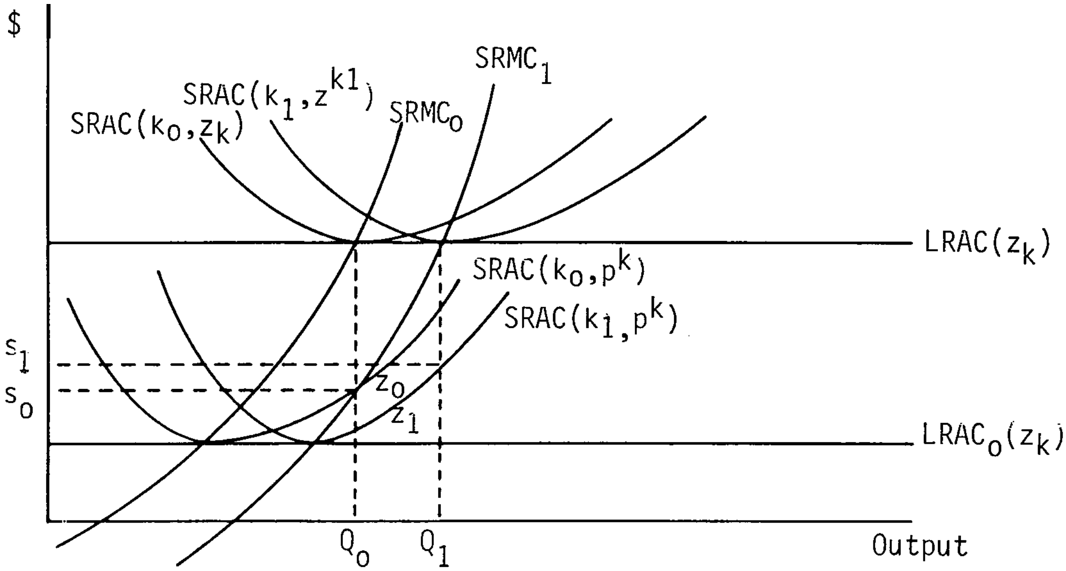
and by rearranging terms,

$$(13) \quad \sigma^{\circ} = -A^{\circ} + \frac{PQ-S}{S}(Q^{\circ} - A^{\circ} - K^{\circ}) .$$

The second term in equation (13) is a capacity utilization measure. If the utility operates at the capacity level, revenue equals cost ($PQ=S$), and the shadow price of capital is equal to long-run price of capital ($P^k=Z^k$). Therefore, at capacity, the SRAC change (σ°) is defined solely by the shift of LRAC ($-A^{\circ}$). Otherwise, the shift in the SRAC (besides, the LRAC shift) is defined by the change in the output-to-capital ratio excluding technological change A°, adjusted by the ratio of profit to cost.

The sense of the second term of equation (13) is illustrated on Fig. 2, assuming $A^{\circ}=0$. Say a utility with the SRAC curve (K_o, P^k) produces output Q, which indicates an overutilization of capital. In order to increase profits, the utility should increase its capital stock, which would shift the SRAC curve to the right.

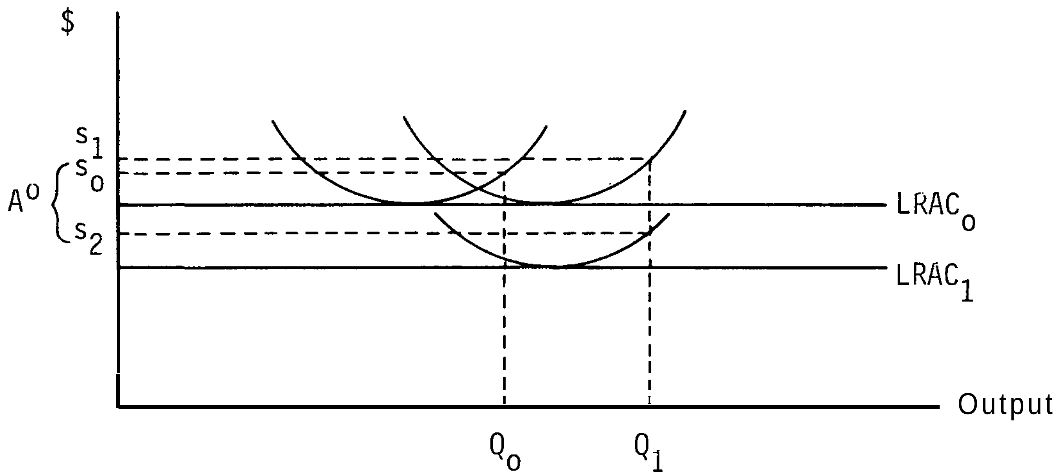
Fig. 2. Short-run Costs, Long-run Costs, and Capacity Utilization



In this case, $K^\circ>0$, $Q^\circ=0$, and $(PQ-S)>0$ imply that the rightward shift of the SRAC curve will lower average costs ($\sigma^\circ<0$ assuming $A^\circ=0$). Since P and Q are fixed, the decline in average costs will raise the profit-to-cost ratio $(PQ-S)/S$. This is different from equation (13) where this ratio is assumed fixed at point Z. Thus equation (13) underestimates the average cost decline in this case. On the other hand, this ratio measured at point Z_1 would overestimate the change in σ°." Similarly, in the case of negative profits, the decrease in capital would lower average costs and a fixed profit-to-cost ratio (at the beginning of the period) would overestimate the cost decline.

Besides the shift from S_0 to S_1, there is a shift in the LRAC, which is measured by A°, (i.e. the vertical shift in SRAC as opposed to the horizontal one discussed above). This is illustrated on Fig. 3.

Fig. 3. Average Cost Change Due to Vertical and Horizontal Shifts in SRAC.



Costs in Fig. 3 have increased from S_0 to S_1 due to the change in capacity utilization and capital-output ratio. But, due to the advancement in technology ($A°>0$), costs have declined from S_1 to S_2.

The second term in equation (13) varies over the business cycle for unregulated industries. In a period of economic expansion, the competitive firm overutilizes its capital because of an increasing profit-to-cost ratio making $\sigma°$ positive (considering $A°=0$). In this case, the profit-to-cost ratio increases and more output is produced per unit of capital ($Q°-K°$). In a period of economic downturn, output will decline toward Q* ($Q°<0$) with a decreasing output-to-capital ratio ($Q°-K°$)<0, making $\sigma°$ negative. Finally, at the trough, Q might be below the optimal level with negative profit and AC will increase ($\sigma°>0$) **if** output continues to decline. When economic recovery returns, output increases and ($Q°-K°$)>0 and AC will start to decline.

In most of the existing TFP studies, the capacity utilization effect is not considered (i.e. σ is equated to TFP). In such a case, TFP has a capacity utilization bias. The direction of the bias for unregulated industries most likely coincides with the business cycle. For this reason, comparison of σ^{o} across unregulated companies might be satisfactory. Nevertheless, comparing TFPs (unadjusted for capacity bias) of regulated and unregulated industries has a serious problem (such comparison was done, for example, by Gollop & Jorgenson [1980]). The deviation of revenue from cost in regulated industries is affected more by the frequency of hearings than the business cycle; it was observed in Ohio that the distribution of hearings does not follow the business cycle; similar observations were made on the U.S. level (see Braeutigam and Quirk [1984]). Thus TFP estimates should be different before and after rate hearings even when the true TFP does not change because Z^{k} varies around rate hearings. For the same reason, TFP comparisons across utilities in different states can be misleading because of the differences in the regulatory lags. Therefore, for the proper TFP measure, the regulatory lag should be taken into account.

Besides measuring the capacity utilization effect, equation (13) can be used to measure the regulatory lag effect on TFP. For this purpose, a shadow price of capital Z^{k} should be compared with the fair-return-on-capital index defined by PUCO. If the shadow price of capital is not equal to the fair return, then two parameters would be changed by regulators: the shadow price of capital and revenues. These changes can be described as follows. Let the fair return on capital be $(Z^{k} + G^{k})$, where G^{k} is simply the difference between Z^{k} and the fair return. Then, according to equation (1), the corresponding revenue is $(PQ + G^{k}K)$. Substituting the new price of capital and revenue figures into equation (11), one derives:

$$(\partial S/\partial K)= P^{k} - (Z^{k}+G^{k}) \text{ and } P^{k}K-Z_{k}K-G^{k}K=S-PQ-G^{k}K.$$

Correspondingly, under the new conditions:

$\frac{\partial s/\partial t}{S} = \frac{PQ+G^kK}{S} A^\circ$ and the term $\frac{PQ}{S} Q^\circ$ in equation (12) is substituted by $(PQ+G^kK)Q^\circ$. Therefore, equation (13) can be rewritten as

$$(14) \quad \sigma^\circ = -A^\circ + \left(\frac{PQ+G^kK-S}{S}\right)(Q^\circ-A^\circ-K^\circ) = -A^\circ + \frac{PQ-S}{S}(Q^\circ-A^\circ-K^\circ) + \frac{G^kK}{S}(Q^\circ-A^\circ-K^\circ)$$

The last term on the right in the above expression is a regulatory lag effect on the change in TFP. Note that it equals zero when G^k is equal to zero, that is, when the shadow price of capital is equal to the fair return on capital. Finally, noting $Q^\circ-K^\circ-A^\circ=\Sigma s_i i^\circ-(\sum s_i)K^\circ$, where i=L,E,M, and rewriting A° in its static and dynamic components (see equation [9]), equation (14) can be rewritten as[7]:

$$(15) \quad \sigma^\circ = (E_{CQ}-1)Q^\circ+D^\circ + (\Sigma s_i i^\circ-(\Sigma s_i)K^\circ)\bullet\frac{PQ-S+G^kK}{S}, \text{ where } i=L,E,M.$$

Since all the parameters in equation (15) can be calculated, D° can be computed as a residual. In this study, P^k and G^k for utilities were not estimated and thus the D values derived from equation (14) (which would be different from D values derived in equation (7)) are not available.

How Fair is the Fair Rate of Return Regulation?

In the first period, 1963-1969, utilities rarely requested rate hearings (see table 3), which suggests that their return on capital was greater or equal to the fair return (as defined by PUCO), that is, $G^k<0$ The AC decline during this period contributed to utility profits without the need for mandatory electricity price increases (see table 1). Thus, during the first period, utilities were interested in maximizing TFP growth because it was translated into profit.

According to a popular view developed by Joskow (1974), an electricity regulator is an extremely passive agent. Price changes should be triggered by a request from utilities or consumer advocates. Utilities, however, have a much better knowledge of their present and expected profit than consumer advocates. Consumer advocates are more concerned with price increases than with utility profits. In the first period, electricity prices were declining, which would make consumer advocates hesitant to request an even lower price decreases. Thus, utilities were in a position to gain extra profit given the passivity of the regulator. As a result, during the first period, an extremely long regulatory lag occurred. In the second period, 1969-1973, AC increased slightly, which triggered a modest increase in the frequency of hearings.

In the third and fourth periods, the situation was very different. Fuel prices started to increase very quickly, due to the Arab oil embargo[8], as well as to other input factors, such as inflation. These were <u>shocks</u> to utility operating costs. For a given electricity price, such operating-cost increases drove utility profits below the fair return. Utilities promptly responded to this shock by requesting electricity price increases that, in most cases, were granted. The frequency of hearings increased sharply as utilities had trouble keeping up with the effects of these shocks. Moreover, a decline in productivity ($D^{\circ} > 0$) contributed to the rise in AC. The productivity decline could have been due to a number of intangible factors, some of which are under a utility's control. Therefore, the decline in TFP might have been due to a lack of incentives provided by the regulatory process during the last two periods. The hypothetical argument for such a possibility is illustrated below.

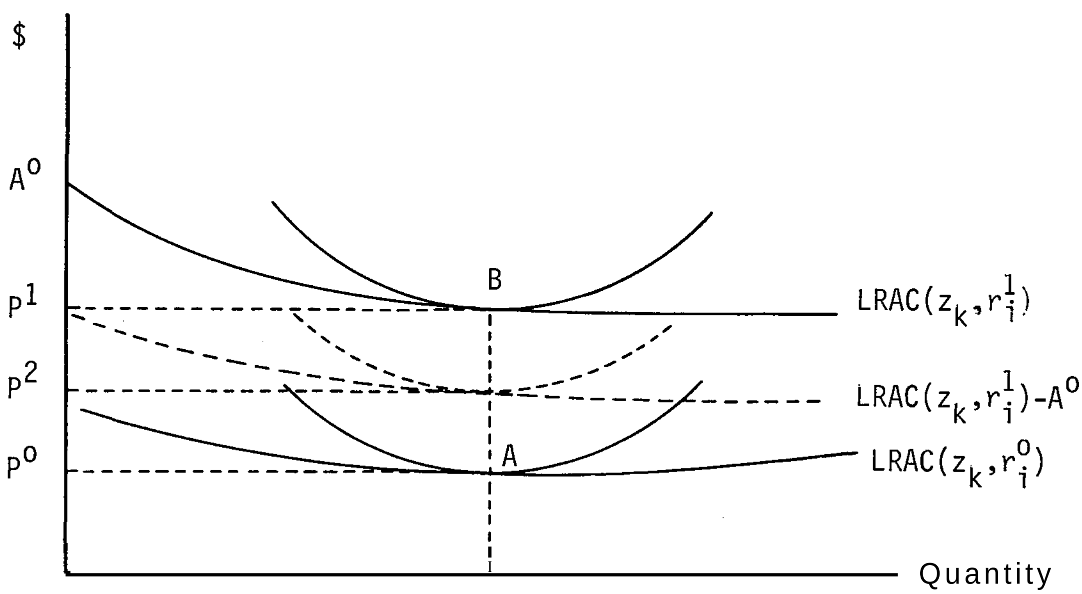
Assume that price P_0 (in figure 4) is the equilibrium. Due to a sharp input-price increase, LRAC moves up to point P_1. Area P_0ABP_1 is the loss per unit of output. In this case, utilities will be granted a price increase of (P_1-P_0). Such a price setting process in general takes a year, following a utility's request. Now, consider that the utility could have increased its TFP to partly offset the impact of the price hike, so that instead of increasing cost to the P_1 level, it would have increased costs only to the P_2 level (and correspondingly request price P_2 instead of P_1). If stable input prices are expected in the next year, the utility may not be willing to increase its TFP. Instead, the utility would raise the price to P_1, and in the next year, it would lower the cost per unit of output by A°. If output remains the same, in the second year the utility would regain the loss of the previous year, which was due to having $A^{\circ}=0$. Nevertheless, if output increases, the gain in the second year (from suppressing $A^{\circ}=0$ in the first year) will exceed the losses. This simplistic example illustrates the lack of incentives for utilities to increase their TFP under these conditions.

TABLE 2: FREQUENCY OF PUCO RATE HEARINGS

YEAR:	% OF UTILITIES REQUESTED RATE INCREASE
1964	0
1965	14
1966	0
1967	0
1968	0
1969	14
1970	14
1971	14
1972	29
1973	86
1974	29
1975	86
1976	100
1977	57
1978	57
1979	57
1980	71
1981	86
1982	100

Source: Rate cases filed; material provided by PUCO.

FIGURE 4. Two-Year Plan



Conclusion

Input prices and productivity changes are two major sets of factors affecting utility operating costs. While input prices are little affected by a utility, its productivity changes are mostly the result of its long- and short-term planning. Yet PUCO grants equal significance to both sets of factors in their process of electricity price determination. As a result, the present regulation may not provide an adequate incentive for a utility to lower its cost by means of raising its TFP level.

In this paper, three types of factors determining shifts in the SRAC curve were considered. Each of these factors (technological change--D, return to scale effect--$E_{CQ}\dot{Q}$, and capacity utilization effect--equation (14)) is a result of different activities and should be weighted differently in the price determination process.

It was indicated that, contrary to common practice, TFP measurement without consideration of the capacity utilization and regulatory lag effects, is inadequate for comparing regulated and unregulated sectors.

The most controversial of these three factors is technological change (D) because the determinants of D are poorly understood. Nevertheless, economists are making initial strides in understanding this factor. For example, Gollop and Roberts (1983) developed a method to consider pollution control bias in the determination of technological change. Obviously, more work is needed in this direction to give regulators valuable tools for measuring different economic and managerial activities.

FOOTNOTES

1. For the discription of the "Fair" rate of return, the **Hope** case is often cited in the literature: "Rates, which enables the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risk assumed ...". Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

2. 20 percent is an upper boundary for an anual price increase established by PUCO.

3. For details on the Tornquist approximation, see Cowing, et. al. (1981)

4. These utilities are: Ohio Power, Cincinnati Gas and Electric, Cleveland Electric Illuminating, Columbus and Southern Ohio Electric, Dayton Power and Light, Ohio Edison, and Toledo Edison.

5. In case of constant returns to scale, this point is always at the minimum of SRAC.

6. This problem is similar to the question of whether to measure shares for Divisia index at t or t+l period. The Tornquist approximation suggests an average share of two periods.

7. The expression for $Q^\circ - K^\circ - A^\circ$ can be derived as follows $A^\circ = Q^\circ - \Sigma s_i i^\circ$ for i = K,L,E,M or $-Q^\circ + \Sigma s_i i^\circ - (1-s_k)K^\circ = -K^\circ - A^\circ$ for i = L,E,M, then $Q^\circ - K^\circ - A^\circ = \Sigma s_i i^\circ - (\Sigma s_i)K^\circ$ for i = L,E,M

8. Ohio utilities consume coal, which had a much less severe price increase than oil fuel.

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Appendix I The Derivation of Equation (11)

We prove that $\frac{\partial S}{\partial K} = P^k - Z^k$

From equation (10), we derive

$$(1.1)\quad \frac{\partial S}{\partial K} = P^k + \sum_{i \neq K} r_i \frac{\partial i}{\partial K}$$

where $\frac{\partial i}{\partial K}$ is the marginal rate of technical substitution (MRTS). In the SR, output is a function of quasi-fixed capital and of variable inputs, which depend on given capital:

$$Q = f[K, L(K), E(K), M(K)] \equiv f(X)$$

Rates of technical substitution can be derived holding output fixed, with corresponding inputs combination X^*:

$$\frac{\partial f(X^*)}{\partial K} + \Sigma \frac{\partial f(X^*)}{\partial i} \bullet \frac{\partial i}{\partial K} = 0$$

where i = L, E, M. For the proof, we have to derive MRTS for any single variable. Consider labor to capital MRTS then from the above equation for i = L:

$$(1.2)\quad \frac{\partial L}{\partial K} = -\frac{\partial f(X^*)/\partial K}{\partial f(X^*)/\partial L} - \frac{\partial f(X^*)/\partial E}{\partial f(X^*)/\partial L} \bullet \frac{\partial E}{\partial K} - \frac{\partial f(X^*)/\partial M}{\partial f(X^*)/\partial L} \frac{\partial M}{\partial K}$$

In the SR:

$\frac{\partial f(X^*)}{\partial K} = Z^K$ and $\frac{\partial f(X^*)}{\partial i} = r_i$. Then substituting (1.2) into (1.1),

$$\frac{\partial S}{\partial K} = P^K + r_L \frac{\partial L}{\partial K} + r_E \frac{\partial E}{\partial K} + r_M \frac{\partial M}{\partial K}$$

$$= P^K + r_L \left(-\frac{Z^K}{r_L} - \frac{r_E}{r_L} \frac{\partial E}{\partial K} - \frac{r_M}{r_L} \frac{\partial M}{\partial K}\right) + r_E \frac{\partial E}{\partial K} + r_M \frac{\partial M}{\partial K}$$

$$= P^K - Z^k$$

Q.E.D.

Appendix II. Derivation of equation (12).

Based on the short-run cost function (10) we derive equation (12), as follows:

$$\frac{dS}{dt} = \frac{\partial S}{\partial K}\frac{dK}{dt} + \Sigma \frac{\partial S}{\partial r_i}\frac{dr_i}{dt} - \frac{\partial S}{\partial t} + \frac{\partial S}{\partial Q}\frac{dQ}{dt}$$

$$= (P^k - Z^k)K \bullet K^\circ + \Sigma\, i \bullet r_i \bullet r^\circ_i - \frac{\partial s}{\partial t} + PQ \bullet Q^\circ$$ then, dividing

both sides by S

$$S^\circ = \frac{(P^k - Z^k)K}{S} K^\circ + \Sigma s_i r^\circ_i - \frac{\partial s/\partial t}{S} + \frac{PQ}{S} Q^\circ$$

Appendix III

Revenue (Electric operating revenue) represents total operating revenues from the sale of electricity.

Output (Electric sales) represents the total kilowatt hours of electricity sold to all residential, commercial and industrial customers including sales for resale.

Fuel Operation Expense represents the total cost of fuel used exclusively for production of electric energy.

Average Cost of fuel per million Btu, represents the total cost of fuel consumed for electric generation divided by its total Btu content.

Material Expense was derived from Electric Operating Expenses minus taxes, labor and fuel expense.

Material Price Index. Handy-Whitman cost (index of Utility Plant Materials.

Rate Base is computed as a sum of Net Utility Plant and the Change in Working Capital. This computation is consistent with a regulatory definition of the rate base.

Return on Capital is computed as a ratio between Operating Income and the rate Base.

Net Utility Plant represents the historical cost, less accumulated depreciation of the total fixed utility plant and equipment.

Change in Working Capital represents the amount of cach or liquid assets a company must have to meet current costs until reimbursed by its customers.

Operating Income represents total operation revenues earned from electric services minus total operating expenses.

Number of Employees is electric department employees where each part-time worker is counted as one-half of a full-time employee.

Labor Expenses is defined as total salaries and wages charged to electric operation and maintenance production.

Wage Rate is measured as labor expenses divided by the number of employees.

Number of employees and labor expenses were derived from "Financial Statistics of Selected Electric Utilities." The rest of data were derived from Cornpustat Co.