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Assessment of Social Value for a Nuclear-Fueled Electric Economy with Application to the European Community

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This essay focusses on an important public decision problem in energy policy to add on the basis of a given set of coal-fired power plants to generate electricity either nuclear-fueled power plants or another set of coal-fired power plants. To make decisions of that sort with long-run impacts we introduce as valuation criterion the "incremental net social benefit" (INSB) as the difference between the "incremental social benefit" (ISB), caused by the newly introduced technology of electric power generation and the "incremental social cost" (ISC), induced by this technology.

1. Introduction

The purpose of this paper is to assess the "incremental net social benefit" resulting from nuclear-fueled, rather than coal-fired electric power generation.

The "incremental net social benefit" (INSB) is defined as the difference between the "incremental social benefit" (ISB) (caused by the cheaper technology of electric power generation) and the "incremental social cost" (ISC) (associated with an increased power production, which is induced by cheaper technology).

The social cost includes:
(1) Private production cost.
(2) Social damage cost.

Private production cost includes four components:
(a) Generation cost.
(b) Transmission cost.
(c) Distribution cost.
(d) Abatement cost.

The abatement cost is determined by the pollution emission and safety standards, which are set by public regulatory commissions.

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Social damage cost is associated with the damage that is not eliminated by the emission and safety standards (see Fig. 0). In the following we shall use traditional economic instruments for measuring the incremental social benefit (ISB) and incremental social cost (ISC). In Figure 1, D is the aggregate demand curve for electric power, $S_o S_o$ is the long-run social supply curve for power generated by coal-fired plants, and $S_1 S_1$ is the long-run supply curve of a system that uses coal-fired plants for the production of the first q_o kWh, and new nuclear-fueled plants for quantities exceeding q_o.

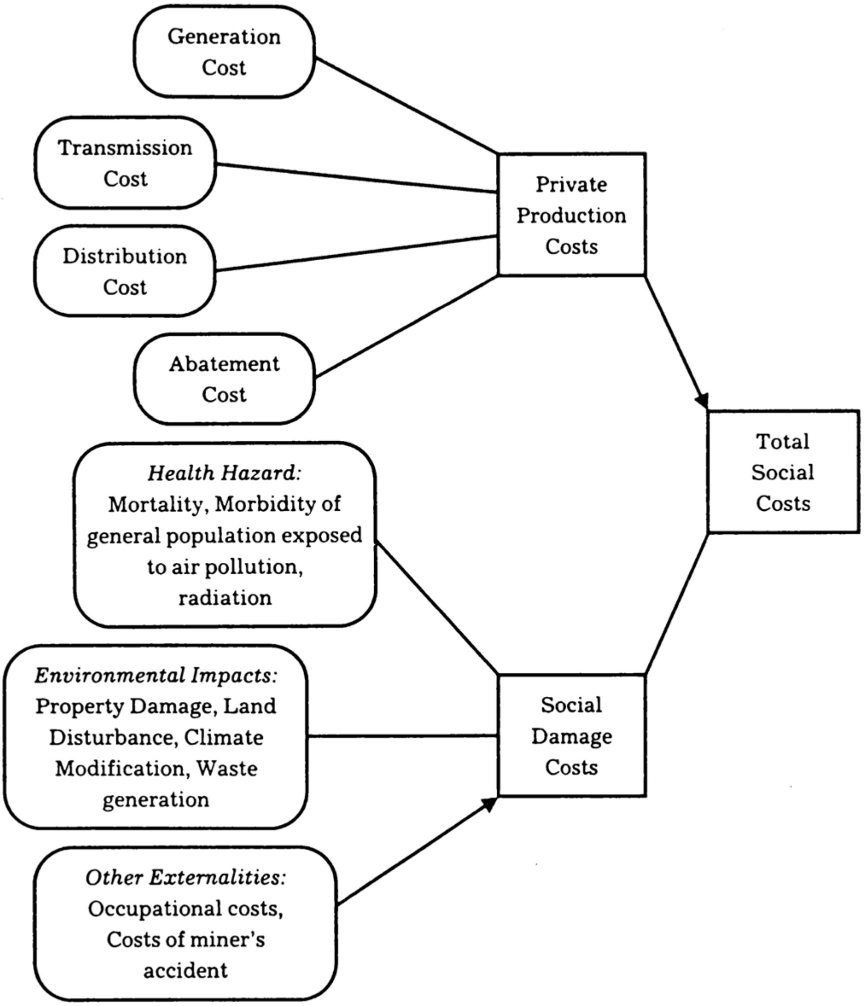

Fig. 0: Structure of Cost Calculation for Electric Power Generation

Remarks: All studies on policy options regarding the production of electricity, as indicated in the references, attempt to identify comprehensive cost modules for estimating the extent of (incremental) social costs

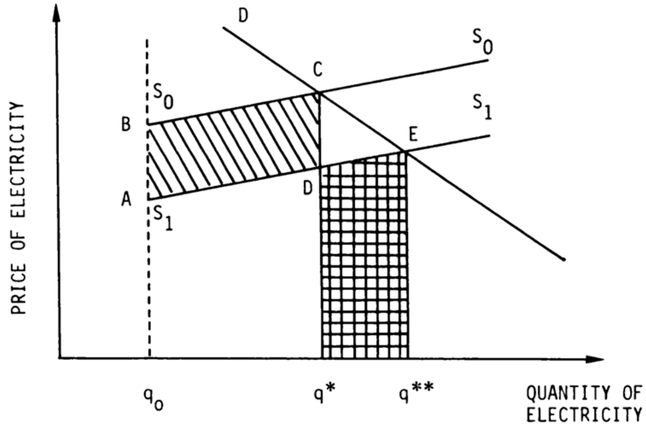

Fig. 1: The Incremental Net Social Benefit

Let q^* designate the equilibrium quantity of a coal-fired electric power system. Let q^{**} designate the equilibrium quantity that is generated by a system using old coal-fired and new nuclear-fueled plants. Also, let us assume that the social supply curve, for quantities greater than q_o, is lower for the second system than for the first one. Therefore the relation is: $q_o < q^* < q^{**}$. Then, the incremental social benefit (ISB) equals the incremental gross social benefit (IGSB) plus the cost saving (CS), i.e. ISB = IGSB + CS.

The incremental gross social benefit is the area below the demand curve between q^* and q^{**} ($q^{**}\mathrm{CE}q^{**}$ in Figure 1). The cost saving is the area bounded by the two social marginal cost curves, between q_o and q^*. The incremental social cost (ISC) is measured by the area below the lower social supply curve between q^* and q^{**} ($q^*\mathrm{DE}q^{**}$ in Figure 1). If we subtract the latter cost component from both sides of ISB, we get: INSB ≡ CS + IGSB − ISC = ISB − ISC.

If we define the difference between the last two terms as "surplus", we get the following relation: INSB ≡ Cost Saving + Surplus. These accounting equations are generic for Pareto-type cost-benefit analysis.[1, 2]

2. Problems of Net Social Benefit Assessment

In the sequel, let us focus on:

(1) The theoretical and empirical problems associated with the assessment of the long-run price elasticity of the demand for electricity.

[1] *Hirshleifer* (1974).

[2] *Gottinger* (1983).

(2) The theoretical-econometric considerations that led us to choose reasonable estimates of price elasticities of demand from those provided by recent empirical studies.

(3) The theoretical and empirical difficulties associated with the construction of the long-run social cost curves (LRSMC) of electricity.

(4) The construction of two suggested sets of LRSMC curves.

We deal with the assessment methodology, and provide numerical examples for the calculation of the INSB resulting from nuclear-fueled power generation.

The main result of our exercise (Sec. 8) is that the use of nuclear-fueled plants in the future would lower the social cost of electricity in comparison to the usage of coal-fired plants. Consequently, it would increase the long-run annual power consumption by amounts ranging between 10% and 35%, depending on the assumed values of the long-run price elasticity of demand, and on the long-run social marginal cost curves.

3. The Price Elasticity of the Demand for Electricity and the Multipart Demand Curve

In order to estimate the "cost saving" and the "surplus" in nuclear-fueled electric power generation, we shall estimate the long-run demand curve for electricity; evaluate the existing empirical studies; and suggest a reasonable price elasticity. Electricity is an input in industrial and domestic production. It is produced by utilities that are subject to public price regulations to prevent the exercise of monopoly power. Equating the long-run marginal cost with the prices that are subject to increasing returns to scale, will impose losses on the utilities. In reality there are multipart "declining block" rates as a solution on the pricing dilemma.

The long-run total cost of the public utilities can be covered by different rate structures. This implies that, for a given average price, different amounts of electricity can be demanded by the same individual (or two individuals with the same tastes and endowments) who faces the same average price resulting from different "declining block" rates. This can be illustrated by the following experiment.

Denote the goods by q_1 and q_2, and assume that q_2 can be purchased at a price p_2, but that q_1 (electricity) is purchased according to a two part tariff with decreasing block rates as follows (see Figure 2):

1st kWh's (or less)	Z_o
M to N kWh's	π_1/kWh
more than N kWh's	π_2/kWh

where $\pi_2 < \pi_1$.

Usually every product has a single price only, in which case the budget line is linear. However, with a price schedule for q_1, the budged constraint becomes nonlinear. Its general appearance is given by the curve ABCDE in Figure 2. Suppose that the individual equilibrium occurs at point F in Block π_2, where the indifference curve U_o is tangent to the segment DE. Let us consider another decreasing block scheme for the same individual, which forms the budget constraint AHJKL with the corresponding equilibrium at point G so that AR/RG = AS/SF. In other words, we can choose an alternative scheme in such a way that the average price paid to the electric utility will be the same at both equilibrium points. Although the prices are the same at points G and F, the demanded quantity is smaller in the second scheme (with a higher marginal price), than in the first one (OQ < OP).

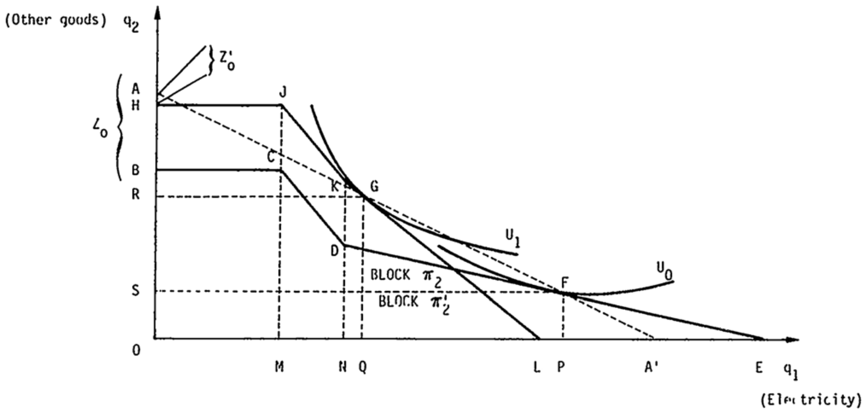

Fig. 2: Two-Part Tariff System

This analysis shows that by changing the avarage price of electricity the future demanded quantity cannot be predicted unless the entire price schedule is considered.

The declining block rate pricing principle (like any multipart pricing) used by the public utilities, extracts a part of the consumer's surplus. The regression of the demanded quantity of electricity on the average price does not result in an ordinary demand function with uniform prices for all the units. The demand curve that describes the relationship between the average price paid by the users of electricity, and the demanded quantity, will be called the "multipart demand curve" (MD).

This curve lies between the ordinary demand curve D_o and the "zero-surplus demand curve" D.[3] Hence, the area below MD overestimates the

[3] The "zero-surplus demand curve" represents the maximum average price that the consumer is willing to pay for any quantity. If he is charged according to this curve,

social benefit resulting from electricity consumption. This bias is shown by the shaded area ACD in Figure 3.

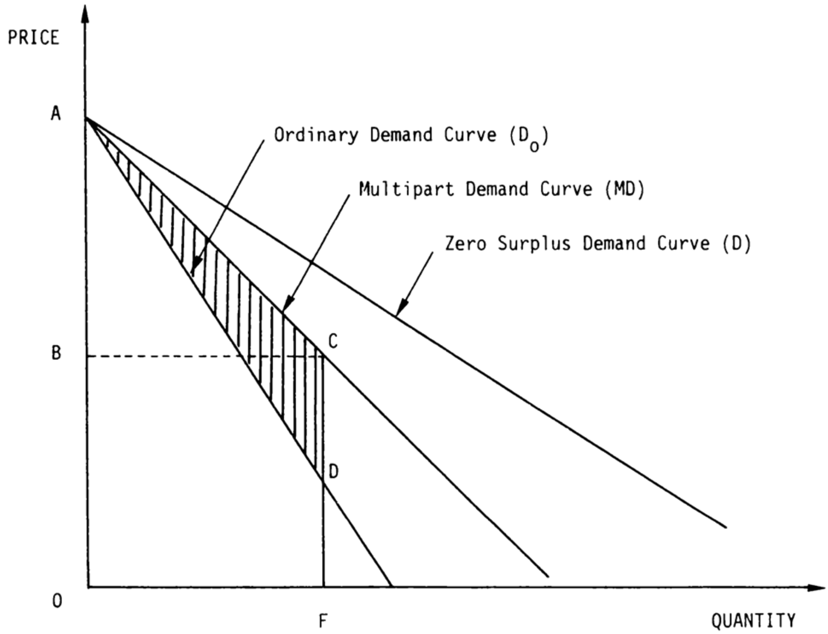

Fig. 3: The Multipart Demand Curve Versus the Ordinary Demand Curve

4. Assumptions on Approximation to Market Equilibrium

This analysis would be somewhat different if it were applied to the increments of the generated electricity at hypothetical initial market equilibrium quantity, and if we could approximate the price elasticity of the ordinary demand curve at this point. For this purpose let us make the following assumptions:

(1) The long-run social marginal cost (LRSMC) of the electricity production is known.

(2) The electric utilities are operating in the region of long-run increasing marginal cost, and they use the two-part tariff scheme so that the marginal cost is lower than the high block rate, but is higher than the low block rate (marginal price).

he will not benefit from the consumer's surplus. The exact location of MD will depend on the specific features of the multistep pricing scheme. In the extreme case, when the utility employs flat rate pricing, the multipart demand curve will coincide with the ordinary demand curve.

As a historical note, the concept of "zero-surplus demand curve" is equivalent to von Stackelberg's "Ausbeutungskurve" (see *Stackelberg* (1950)).

(3) The quantity of the demanded electricity, subject to the above scheme, is equal to the demanded quantity subject to an alternative scheme, that would set a uniform price equal to the marginal cost.

(4) Conditions (2) and (3) will continue to hold if the electric utilities will use cheaper technologies (in this case nuclear-fueled plants), that will lower the long-run marginal cost, and hence the price of electricity.

Assumptions (2) and (3) are shown in Figure 4.

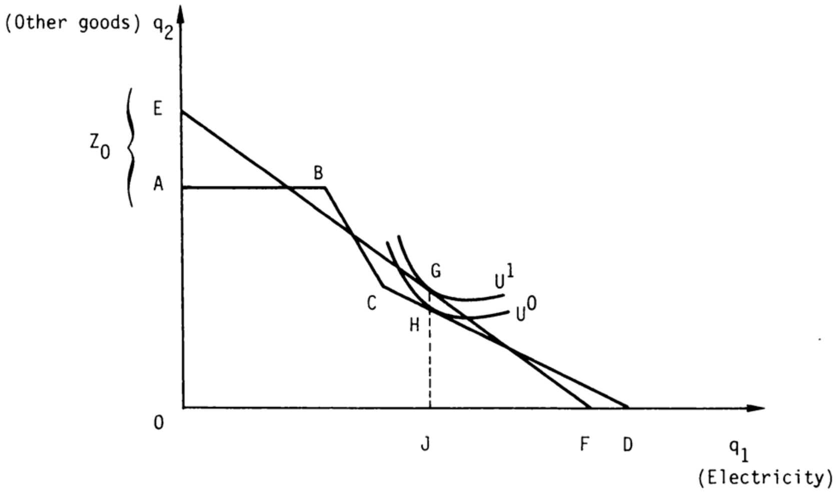

Fig. 4: The Equivalent Quantity of Demanded Electricity Subject to the Two-Part Tariff Scheme and the Flat Rate Scheme

The inframarginal price is given by the slope of the linear segment BC. The marginal price is given by the slope of CD. The uniform price is represented by the slope of EF. (Note that the slope of the indifference curve U' at point G is larger than the slope of the indifference curve at U^o at point H. This seems to be consistent with the notion that electricity is a superior good, i.e. the demanded quantity increases with the increase of the nominal income.) Assumption (3) is represented by the vertical alignment of G and H at quantity OJ.

By assumption (1), (2), (3), and with a quantity of electricity in equilibrium (which is known) we know that the ordinary demand curve D_o and the long-run social marginal cost curve (LRSMC) should pass through point C in Figure 5. However, the price elasticity of demand is not known at this point.

Suppose that we use the known price elasticity of the curve MD at point A, as an approximation. Geometrically that can be done in the following way. Draw a tangent to the MD curve at point A, then construct a line that connects point B (the intersection of the tangent with the horizontal axis) to point C. The resulting DB line will be called the "instrumental curve" (IC). It can be seen that the price elasticity of the MD curve at point A (given by AB/NA) is equal to the price elasticity of IC at point C (given by CB/DC). Therefore, instead of using the multipart demand curve at point A, we can use the instrumental curve at point C.

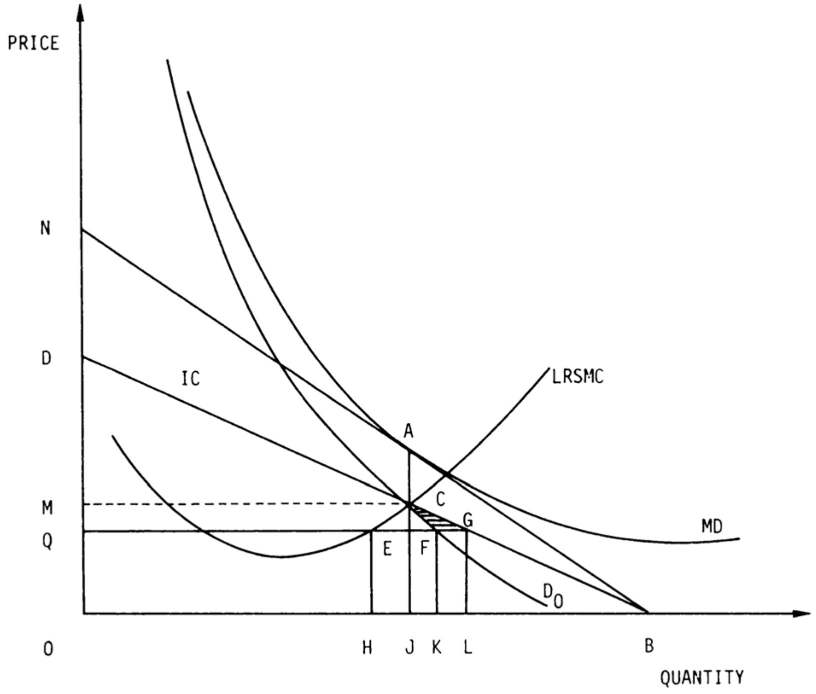

Fig. 5: Approximation of the Price Demand Elasticity
by the Average Price Elasticity of MD Curve

In Figure 5, OJ and OM indicate the equilibrium quantities and the price of electricity produced by an electric utility system, using the old techniques. If new and cheaper techniques are available (so that the LRSMC becomes horizontal at a level OQ in region $q > OH$), the resulting new equilibrium quantity and price of energy will be given by OK and OQ, respectively. The associated incremental social benefit will be the area EFC. However, since we do not know the shape of the demand curve at point C, we shall use the area ECG as an approximation of the incremental social benefit. The "bias" resulting from the approximations is the shaded area CFG. This is relatively small in the present case, since we are dealing with small changes.

5. Empirical Considerations

A major problem associated with the estimation of the demand function for electricity is the peak-load pricing problem. Most of the empirical studies ignored the differential prices relating the peak load and off-peak load periods. The peaking phenomenon has scarcely been investigated, with some notable exception recently (*Aigner* (1984)). In principle, one should review the demand separately for peak and off-peak hours. If we are interested in the total demand in a certain period, the price of electricity of peak load and off-peak load hours should be included in the demand equations, otherwise the price elasticity of the multipart demand may be underestimated or overestimated.

For example, if time series data are used, and the average price is negatively correlated with the "price of electricity at off-peak period/price of electricity at peak period" ratio, and this ratio is negatively correlated with the demanded quantity of electricity, then the price elasticity of the multipart demand curve would be underestimated.

For lack of sufficient empirical data, the magnitude of the upward or downward bias cannot be calculated, so no adjustment has been made here for the peaking problem.

Now we are looking for an estimate of long-run price elasticity of demand in order to assess the incremental social benefit associated with nuclear-fueled power generation.

Instead of attempting to get a new estimate for the price elasticity of demand, we shall use some recent econometric studies.

Note, however, that since the electric utilities employ the declining block rate schemes, the coefficient of the "average price" in the regression equation should be interpreted as the price elasticity of the multipart demand curve rather than as the price elasticity of the ordinary demand curve.

However, since the latter estimated elasticity is not available, we shall use empirical figures as substitutes for the former one. Throughout, the notation "demand curve" will refer to the "multipart demand curve."

In previous studies there is considerable variation in the values of the estimated price elasticities: Some of the reasons are:

- Different vectors of variables used to explain the variations in the demand for electricity.
- The replacement of theoretical variables by observed ones (for example, different index variables for estimating the effect of the permanent income on the consumed energy).

- The difference in the data used. Some studies use cross-section data, others use time series, or pooled cross section and time series data.
- Different periods and different levels of aggregation chosen in the various studies.
- Several researchers who estimated the demand equation did not pay enough attention to specification problems, or to other econometric considerations. Consequently, in several studies the estimates are biased and inconsistent.

The choice of the proper price elasticities has some crucial implications for the net social benifit calculations. The higher is the recommended elasticity, the higher will be the estimated social benefit resulting from the adoption of the nuclear technique. As *Taylor's* survey[4] indicates there are not too many estimates to choose from for the price elasticity of demand for electricity in the commercial and in the industrial sectors. However, there are several options for the price elasticity selection in the residential sector. The range of the price elasticity of aggregate demand for electricity, derived from various studies, as surveyed by Taylor, lies between −1.1 and −1.8, with the average of the commercial, industrial and residential elasticities being −1.4, −1.8, and −1.1, respectively.

However, to test the sensitivity of this analysis for the validity of the assumed price elasticities, we will also use various figures in that range for the net social benefit calculation.

Thus, because of this and in view of most recent data by Mitchell[5] our LRMC estimates prove to be highly robust, and we feel confident that the results reflect present conditions.

6. Long-Run Social Marginal Costs

Specific studies were presented by *Anderson*[6] and by the Stanford Research Institute Group, i.e. by *Barrager, Judd* and *North*[7], for the long-run marginal cost of electric power. Anderson gives a range of private long-run marginal cost estimates for the whole electric power industry, but does not state clearly how these change as a function of the output rate. The Stanford Research Institute provided a set of long-run social marginal cost curves for 1,000 MW systems using coal-fired plants only, or nuclear-fueled plants only. Again, it is not clear how their estimates vary with the electric

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[4] *Taylor* (1975).
[5] *Mitchell* (1986).
[6] *Anderson* (1975).
[7] *Barrager / Judd / North* (1975).

power generation rate. Thus, these approaches are not appropriate for the price determination of electricity.

The adavantage of these studies compared to the earlier ones is that their cost estimates explicity include the abatement costs. In addition, the SRI study provides estimates for the social damage cost and Anderson's work gives estimates for the long-run distribution cost.

An interesting approach is shown by Scherer[8] for the estimation of the long-run marginal cost. He uses a mathematical programming model to estimate the power system cost. His model took the peak load into account, as well as the base load service, the transmission cost, and the emission parameter, to estimate the long-run marginal cost. He considered four sets of emission standards, ranging from the levels that would be emitted by uncontrolled plants to technically achievable minimum emissions. However, his estimates do not include the distribution costs and the damage costs incurred by the uncontrolled portion of the emitted pollutants.

The system chosen for his study belongs to the New York State Gas and Electric Corp. (NYSEC). In 1970, this system used coal-fired plants, its peak load was about 1,000 MW, and the load factor was 62.5%. Scherer[3] calculated two sets of long-run average and marginal cost curves for this system. One was for the new coal-fired technology, meeting the future demand for electricity, and another was for the new nuclear-fueled technology (see Appendix).

He computed the abatement cost, while meeting the set emission standards for fly-ash, SO_2, and rejected heat. Other fossil originated air pollutants, and the effects of nuclear plants, were not considered.

The first set (Set I) represents no emission restriction on the system.

Set II and Set III are "absolute standards". That implies that for plants of capacity up to "k" MW, no emission treatment is required. For every unit of capacity beyond "k", a marginal cost of "s" is incurred. Thus, sets II and III induce an increasing average abatement cost as a function of the system's output.

Set IV is a "proportional standard" set, which means that for all larger than zero capacities a marginal cost of "d" is incurred. Therefore, this set induces a constant average abatement cost. It provides: no rejected heat release to the receiving water, 99.5% removal of fly-ash, and 90% removal of SO_2. Set IV is not likely to be socially acceptable and therefore in the following section we shall regard sets I - III as possible options.

Concerning the NYSEC System's long-run average costs, Scherer concluded that "when new plants are nuclear-fueled, the system's nuclear-

[8] *Scherer* (1976).

fueled average costs are decreasing over the entire range of emission standards, whereas when new plants are coal-fired, costs are increasing as the system size increases". Also, he found that the long-run average cost of new coal-fired plants was significantly higher than the corresponding cost of nuclear-fueled plants for any peak load, and for any range of pollution emission standards. In order to estimate the long-run social marginal cost of the electric power system, we should determine the optimum level of emission and safety standards and the social cost associated with them. With a socially optimal resource allocation, there is a positive level of damage to the public because the marginal abatement cost is an increasing function of the damage abatement, whereas the marginal social benefit emerging from the damage elimination is a decreasing function of the damage abatement.

It is difficult to empiricially determine the abatement cost and the associated social demand cost since we do not know the estimated demand for "damage elimination" and the continuous marginal abatement cost curve.

The social damage cost does not include the cost of a meltdown, or other costs of a reactor accident.

Because evaluating such costs is likely to encounter quite a few "stumbling blocks", i.e.

- there is still insufficient information about long-term effects on the environment of even relatively low levels of radioactivity (which is the classical case of uncertainty).
- there is unsatisfactory information about the reliability of existing safety systems in man-machine interaction. Reliability estimates are based on computer models whose component parts have empirical validity, but taken as a whole, have been subject to little empirical verification. An implicit assumption is made by the independence of errors on any critical part. Thus errors are calculated additively. However, in the context of man-machine interaction a more plausible hypothesis is that errors are reinforcing, hence one error enhances the likelihood to make another error. In a situation of crisis proportion error generation follows some exponential law.
- how to cope with very small probabilities of very large, long-term and irreversible losses? Does the computation of expected values and their certainty equivalents apply to extremely small probabilities of extremely large losses?

7. Incremental Net Social Benefit (INSB)

To calculate the INSB of a new nuclear-fueled system that can meet the demand for increased electricity in the future, we shall take the following approach. First, we shall calculate the INSB for an existing "typical system". Then, we shall multiply the result by $1/\beta$, where β is the share of the typical system within the total electric power industry.

We shall use as a "typical" one for our calculations a system that had a 1,000 MW capacity in 1980, and would have reached 1,275 MW (or 7×10^9 kWh) annual capacity in 1985, if we assume a 5% year growth-rate in power production, which seems to be realistic, at least in the long-run. To simplify the LRSMC curves, let us define the following values:

Simplification of LRSMC-Curves

(1)
$$\mathrm{LRSMC}_1 = \begin{cases} a_1 + b_1(Q - q_0) & q_0 \leqslant Q \leqslant q_1 \quad a_1 > 0, b_1 > 0 \\ a_2 - b_2(Q - q_1) & q_1 \leqslant Q \leqslant q_3 \quad a_2 > 0, b_2 > 0 \\ a_3 + b_3(Q - q_3) & q_2 \leqslant Q \leqslant q_4 \quad a_3 > 0, b_3 > 0 \end{cases}$$

(2)
$$\mathrm{LRSMC}_2 = \begin{cases} a_4 + b_4(Q - q_0) & q_0 \leqslant Q \leqslant q_1 \quad a_4 > 0, b_4 > 0 \\ a_5 - b_5(Q - q_1) & q_1 \leqslant Q \leqslant q_2 \quad a_5 > 0, b_5 > 0 \\ a_6 + b_6(Q - q_2) & q_2 \leqslant Q \leqslant q_3 \quad a_6 > 0, b_6 > 0 \end{cases}$$

The curves corresponding to the newly defined LRSMC values are shown in Figure 6 (p. 106).

The typical aggregate long-run demand curve for electricity is given by:

(3)
$$Q_t = AN_t^{\alpha_0} PC_t^{\alpha_1} PG_t^{\alpha_2} Y_t^{\alpha_3} PE_t^{-\alpha_4}$$

where

Q_t = the demanded quantity of electricity by all the sectors in period t
N_t = the population in period t
PC_t = the price of appliances in period t
Y_t = the anticipated permanent income in period t
PE_t = the price of electricity in period t
α_4 = the long-run price elasticity of demand for electricity
PG_t = the price of electricity consuming industrial machinery.

In Figure 6 the two long-run social marginal cost curves (LRSMC_1 and LRSMC_2), the aggregate demand curve, and the social equilibrium solutions are shown. The long-run demand curve could shift during a certain time interval as a result of changes in the anticipated permanent income per capita, population size, or tastes. The long-run social marginal cost could also change within a time interval, as a consequence of technological advancement and variations in the long-run relative prices of raw materials and labor inputs.

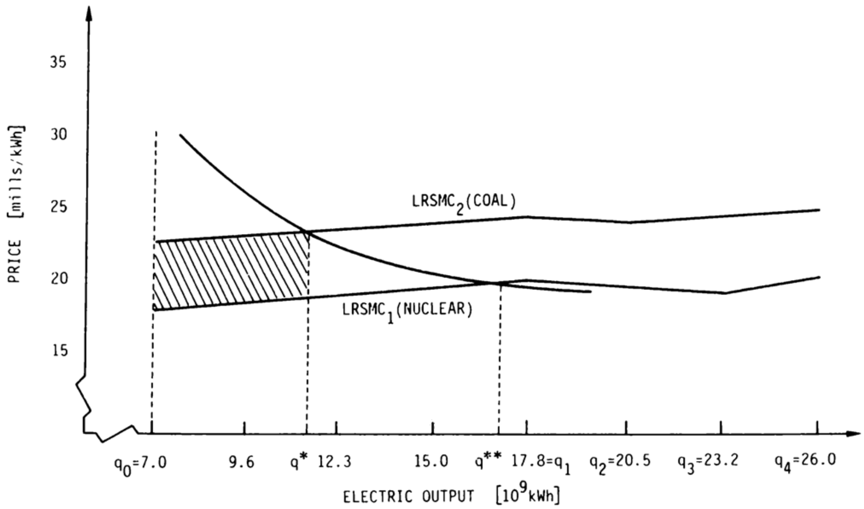

Fig. 6: The Long Run Social Marginal Cost (LRSMC) Curves of Electricity Generated by a Representative Electric Power System, and the Intersecting Aggregate Long-Run Curve (1975 Prices)

By substituting $B_t = AN_t^{\alpha_0} PC_t^{\alpha_1} PG_t^{\alpha_2} Y_t^{\alpha_3}$ Equation (3) can be written as:

(4) $$Q_t = B_t PE_t^{-\alpha_4}$$

and

(5) $$PE_t = B_t^{1/\alpha_4} Q_t^{-1/\alpha_4}$$

Using (1), (2), and (5), and by assuming, that the equilibrium points (determined by LRSMC_1 and LRSMC_2) are in the region $q_0 - q_1$ ($q^* - q^{**}$ in Figure 6), the incremental net social benefit (resulting from using nuclear-fueled plants rather than new coal-fired plants) can be obtained as:

(6) $$\mathrm{INSB} = \int_{q^*}^{q^{**}} B^{\frac{1}{\alpha_4}} Q^{-\frac{1}{\alpha_4}} dQ - \int_{q^*}^{q^{**}} [a_1 + b_1 (Q - q_0)] \, dQ$$
$$+ \int_{q_0}^{q^*} [a_4 + b_4 (Q - q_0)] \, dQ - \int_{q_0}^{q^*} [a_1 + b_1 (Q - q_0)] \, dQ$$

or more explicitly

$$\text{(7)} \qquad \text{INSB} = \frac{\alpha_4}{\alpha_4 - 1} B^{\frac{1}{\alpha_4}} \left[q^{**\frac{\alpha_4 - 1}{\alpha_4}} - q^{*\frac{\alpha_4 - 1}{\alpha_4}} \right] - (q^{**} - q^*)(a_1 - b_1 q_0)$$

$$- \frac{b_1}{2} (q^{**2} - q^{*2}) + (a_4 - a_1)(q^* - q_0) + \frac{1}{2} (b_4 - b_1)(q^{*2} - q_0^2)$$

$$+ (b_1 - b_4)(q^* - q_0) q_0$$

The first three terms represent the incremental "surplus" associated with the production expansion from q^* to q^{**} (the dotted area in Figure 6).

The last three terms represent the "cost saving" achieved by using cheaper technology in the production of quantity $q^* - q_0$ (the shaded area in Figure 6).

8. Application to an EEC Energy Regime

We estimate the incremental net social benefit resulting from the adoption of the nuclear technology in electricity production. The estimate refers to a typical electrical power system that produced about 7×10^9 kWh in 1985, or approximately 0.35% of the total electricity generated in the European Economic Community (EEC) of that year. Later we shall multiply the result by $10^4/35$ to get the total incremental net social benefit for the entire electric industry[9].

This exercise will be repeated six times for the calculation of the different alternative pairs, composed of the estimated LRSMC curves and the long-run demand curves. This way we attempt to construct a region of the NSB values that would represent the true value of the social benefit resulting from the employment of the new nuclear-fueled plants. (There is a great uncertainty about the shape of the long-run social marginal cost curves and the long-run demand curves.) The six INSB estimates will correspond to three alternative values of the long-run price elasticity of demand (α_4), and to two alternative sets of LRSMC curves. Table 7 (p. 108) shows these figures.

[9] *This appears to be in agreement with major scenarios of electricity projection for the EEC (Colombo* (1982)).

Table 7

Values of α_4 and LRSMC for NSB Estimates

α_4	α_4^{I}	α_4^{II}	α_4^{III}
LRSMC			
Set I	1	2	3
Set II	4	5	6

Here

$$\left.\begin{array}{lcl} \alpha_4^{\mathrm{I}} & = & 0.8 \\ \alpha_4^{\mathrm{II}} & = & 1.2 \\ \alpha_4^{\mathrm{III}} & = & 1.6 \end{array}\right\} .$$

The α's are the weighted averages of the price elasticities of demand of the three sectors: residential, industrial, and commercial, as taken from various studies.

$$\mathrm{LRSMC}_1^{\mathrm{I}} = \begin{cases} 18.50 + 0.18\,(Q - 7.00) & 7.00 \leqslant Q \leqslant 17.80 \\ 20.40 - 0.17\,(Q - 17.80) & 17.80 \leqslant Q \leqslant 23.20 \\ 19.50 + 0.36\,(Q - 23.20) & 23.20 \leqslant Q \leqslant 26.00 \end{cases}$$

$$\mathrm{LRSMC}_2^{\mathrm{I}} = \begin{cases} 23.00 + 0.18\,(Q - 7.00) & 7.00 \leqslant Q \leqslant 17.80 \\ 24.90 - 0.11\,(Q - 17.80) & 17.80 \leqslant Q \leqslant 20.50 \\ 24.60 + 0.15\,(Q - 20.50) & 20.50 \leqslant Q \leqslant 26.00 \end{cases}$$

$$\left.\begin{array}{l} \mathrm{LRSMC}_1^{\mathrm{II}} = \mathrm{LRSMC}_1^{\mathrm{I}} + 10.0 \\ \mathrm{LRSMC}_2^{\mathrm{II}} = \mathrm{LRSMC}_2^{\mathrm{I}} + 10.0 \end{array}\right\}$$

For all six alternatives we assume the same q^* value. This implies different B_t values, since Q_t and PE_t in Equation (5) are constants, while α_4 increases; the assumed value of B_t should also increase for the equation to be satisfied. Thus the different INSB estimates correspond to the same initial long-run equilibrium quantity achieved by using new coal-fired plants.

In this example q^* is set to $q^* = 11.4 \times 10^9$ kWh, which is equal to the output which would be produced in 1995 by our representative system if we assume a 5%/year growth rate ($7 \times 10^9 \times 1.05 \times 10^{10} = 11.4 \times 10^9$).

The procedure for computing the NSB for each alternative is the following. Substituting $q^* = 11.4$ in the LRSMC_2 curve (Equation (2)) gives the associated equilibrium price PE^*. Substituting the values of PE^*, q^*, and the specific α_4 into Equation (4), it will give the value of B. With α_4 and B

known, Equation (5) gives the corresponding long-run demand curve. The intersection of this curve with the $LRSMC_2$ (Equation (2)) will give the value of q^{**}, so we have all of the neccessary quantities for Equation (7) to calculate the incremental net social benefit. Multiplying the last result by $10^4/35$ gives the total incremental net social benefit for the entire electric power industry.

Table 8 (p. 110) shows the change in the long-run electrical output induced by adopting the new nuclear-fueled technology, and the associated INSB for the six alternative pairs of estimates for demand elasticities and the LRSMC curves. In Table 8 "β" is the share of the typical system within the total electric power industry. Here $1/\beta = 10{,}000/35 \cong 286$.

Table 8 shows that the INSB (resulting from using nuclear technology in future production) ranges from ECU 6.9 billions/year to ECU 8.3 billions/year in 1985 prices. The corresponding rate of increase in the annual electricity output (compared to the output level that could be achieved by the coal-fired technology) ranges from 11% to 32%.

By the adoption of the nuclear-fueled technique, the output of the electric power industry would by 32% higher in 1995 than by using coal-fired technology; 15×10^9 kWh versus 11.4×10^9 kWh. (These figures correspond to $\alpha_4 = 1.6$ and LRSMC Set I in Equation 3). The associated INSB would be \$ 6.3 billions/year in 1985 prices.

With a lower price elasticity of demand ($\alpha_4 = 0.8$), the electricity output would increase by 13%, and the associated INSB would be ECU 7.2 billions/year in 1985 prices.

9. Summary and Conclusion

In this study we have shown how the incremental net social benefit, resulting from the adoption of the nuclear-fueled technology in place of the coal-fired one in electric power production, can be calculated. Using the cost benefit analysis technique, results of empirical studies for the long-run price elasticity of demand for electricity, and the long-run social marginal cost, we were able to measure the incremental social benefit. In our example this figure ranges from ECU 6.9 billions/year to ECU 8.3 billions/year in 1985 prices, depending upon the assumed values for the long-run price elasticity of demand for electricity, and upon the estimated long-run social marginal cost curve. We haven't seen anything in more recent forecasts (*Mitchell / Park /Labrune* (1986)) that so far seems to invalidate the key assumptions on which this analysis was based.

The analysis can be extended to other aspects of direct or indirect costs associated with these options, as done comprehensively by the study of

Table 8: **Change in Electric Output and INSB for Alternative Values of α_4 and LRSMC**

Alternative pairs of LRSMC sets and α_4's			$\frac{1}{\beta}\, q^*$ 10^9 kWh	$\frac{1}{\beta}\, q^{**}$ 10^9 kWh	$\frac{q^{**} - q^*}{q^*} - 1$ 0/0	$\frac{1}{\beta}$ INSB ECU 10^9	Cost saving ECU 10^9	Surplus ECU 10^9
LRSMC^{I}	$\alpha_4 = 0.8$	1	3,257	3,700	13.6	7.237	6.043	1.194
	$\alpha_4 = 1.2$	2	3,257	4,057	24.6	7.611	6.043	1.568
	$\alpha_4 = 1.6$	3	3,257	4,303	32.1	8.257	6.043	2.214
LRSMC^{II}	$\alpha_4 = 0.8$	4	3,257	3,629	11.4	6.932	6.043	0.889
	$\alpha_4 = 1.2$	5	3,257	3,814	17.1	7.014	6.043	0.971
	$\alpha_4 = 1.6$	6	3,257	4,000	22.8	7.552	6.043	1.509

Note: "β" is the share of the typical system within the totl electric power industry. Here $1/\beta = 10{,}000/35$ ω 286.

Gaines / Berry / Long II. (1979) for the U.S. economy and its regional parts, though along this line difficult value judgment problems would have to be resolved.

Zusammenfassung

Hier wird ein Versuch unternommen, den Sozialwert zusätzlicher Kernkraftwerke für eine Stromversorgungswirtschaft abzuschätzen, die durch alte Kohlekraftwerke gespeist wird. Die vorliegende Arbeit geht dabei zwei zentrale Probleme an:

1. Die Bewältigung der theoretischen und empirischen Probleme, die im Zusammenhang mit der Bewertung langfristiger Preiselastizitäten der Nachfrage nach elektrischer Energie stehen.
2. Die Überwindung der theoretischen und empirischen Schwierigkeiten, die mit der Begründung der langfristigen sozialen Grenzkostenkurven der elektrischen Energie auftreten.

Ein praktisches Beispiel wird gegeben, um diese Methodologie auf die Bewertung von Energietechnologien in der Europäischen Gemeinschaft zu erproben.

Appendix

Comparison of two Energy Regimes: Review of Previous Studies

Summarizing the major results of *Scherer's*[1] study, the private average cost (PAC) (excluding the distribution cost) and the abatement cost (ABC) are shown for two systems in 1975 prices. One system uses new coal-firing, the other uses new nuclear-fueling.

In 1970 both systems used old coal-fired plants with 1,000 MW capacity. As mentioned in Sec. 6 we shall regard Set III as the chosen set. In the particular context, this permits 2,570 lb/hr ash emission (compared to 20,000 in Set II and 217,000 in Set 1), 11,000 lb/hr SO_2 (compared to 25,000 and 468,000 in Sets II and I), and permits only 3°F increase in the non-trout stream temperature and only 1°F increase in the trout-stream temperature (compared to 5°F and 3°F in Set II).

With the above assumption, the average cost values in row 1 (coal-fired) and row 4 (nuclear-fueled) represent the long-run private average costs (see Table A.1, p. 112), which consist of the generation cost, the transmission cost, and the chosen abatement cost.

For the final calculation of the "long-run social average cost" curves we have to consider two more components: the "average distribution cost" and the "average social damage cost."

Scherer dit not include the distribution cost of electricity in his model, since these costs are equal for both technologies. In the past, technological advances and scale economics caused by increasing load densities reduced the distribution average cost in real terms, However, in the future, the cost reductions, due to larger scale and technological progress, may tend to taper off.

[1] *Scherer* (1976).

Table A.1: **The Private Average Cost and the Abatement Cost for a Coal-Fired and a Nuclear-Fueled System in 1975 Prices**

Peak load (MW)			1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
Output level (10^6) kWh			5,466	8,200	10,932	13,605	16,398	19,131	21,864	24,597	27,330
Average cost (mills/kWh)											
System with new coal-fired plants	PAC Set III	(1)	10.65	11.39	11.77	12.09	12.38	12.62	12.79	13.00	13.14
	PAC Set I	(2)	10.35	11.00	11.27	11.33	11.38	11.47	11.53	11.62	11.62
	ABC	(3) = (1) − (2)	0.30	0.39	0.50	0.76	1.00	1.15	1.26	1.38	1.52
System with new nuclear-fueled plants	PAC Set III	(4)	10.56	10.47	10.26	10.27	10.08	10.02	9.93	9.80	9.80
	PAC Set I	(5)	10.26	10.08	10.00	9.97	9.78	9.63	9.54	9.50	9.43
	ABC	(6) = (4) − (5)	0.30	0.39	0.26	0.30	0.30	0.39	0.39	0.30	0.37

Note: PAC = Private average cost
ABC = Abatement cost

According to the SRI study the "social damage cost" associated with the coal-fired generator system (at a 1,000 MW peak load) using high-sulfur coal is 4,5 mills/kWh in 1975 prices. The sulfur oxide emission alone accounts for 90% (= 4.1 mills/kWh) of this figure. For nuclear-fueled plants the "social damage cost" is close to zero.[2]

In Scherer's study, a similar coal-fired plant (1,000 MW capacity) to the one in the SRI study, would emit 0.018 lb/kWh sulfur oxide. This is about 78% of the 0.023 lb/kWh emission computed by SRI.

Therefore, if the estimated average social damage cost of the SRI system is 4.5 mills/kWh, Scherer's system will result in 3.6 mills/kWh (1975 prices) average social damage cost.

Having estimated the average social damage cost for 1,000 MW capacity, we can approximate the social damage cost associated with higher peak load levels, but obeying the same emission standard set. Since the emission standard Set III is binding for 1,000 MW capacity, and is an absolute set, it follows that the permitted maximum emittance, and therefore the resulting total cost, is independent from the peak load greater than 1,000 MW. The average social damage cost therefore will be a decreasing function of the output level.

So far we have demonstrated the average social damage cost estimation for Scherer's system using old and new coal-fired plants. In the following we shall calculate the average social damage cost for the same system, using new nuclear-fueled plants. We shall assume that the old coal-fired plant will stop operating when the capacity of the nuclear-fueled system exceeds 2,000 MW. We shall also assume that the old coal-fired plant's operation will gradually decrease, before it stops completely. With a system capacity of 1,500 MW, 50% of the old plant will be shut off. At a system capacity of 2,000 MW, 75% of the old plant will cease operation.

Combining these assumptions with the SRI estimate of zero average social damage cost for nuclear plants, we get the following values:

Peak load 1,000 MW	1	1.5	2	2.5	3	4	5
$ASDC^1$ =	$1 \times ASDC^0$	$\frac{1}{2} \times ASDC^0$	$\frac{1}{4} \times ASDC^0$	0	0	0	0

where $ASDC^0$ and $ASDC^1$ denote the average social damage cost of the coal-fired and the nuclear-fueled system, respectively.

Finally, we can construct the "long-run social average cost" curves. By combining the results in Table A.1 with Anderson's average distribution cost estimate, and with the average social damage estimates, we get the points of the desired curves. Table A.2 (p. 114) tabulates the long-run social average cost for two different new steam plants, operated by a 1,000 MW capacity system in 1970. (The cost figures are given in 1975 prices.)

From the long-run social average cost (LRSAC) figures in Table A.2 (lines (6) and (12)) we can calculate the long-run social marginal cost values for a system that uses new coal-fired and new nuclear-fueled plants. These values are presented in Table A.3

[2] The term "social damage cost" is our terminology. The SRI study refers to this cost as "social cost" (see Tables II-4 and III-6 in the SRI study). It should be emphasized that the "social cost" reported by SRI are not the result of any detailed analysis but are only illustrative, first order estimates. Since our study is also illustrative in this feature, we find it adequate to use the SRI figures.

Table A.2: **Long-Run Social Average Cost for Coal-Fired and Nuclear-Fueled Systems**

Peak load (MW)			1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000
Output level (10^6 kWh)			5,466	8,200	10,932	13,665	16,398	19,131	21,864	24,397	27,330
Long-run average cost (mills/kWh)											
System with new coal-fired plants	Abatement cost	(1)	0.30	0.39	0.50	0.76	1.00	1.15	1.26	1.38	1.52
	Generation and transmission cost	(2)	10.35	11.00	11.27	11.33	11.38	11.47	11.53	11.62	11.62
	Distribution cost	(3)	10.74	10.74	10.74	10.74	10.74	10.74	10.74	10.74	10.74
	Private cost	(4) = (1) + (2) + (3)	21.39	22.13	22.51	22.83	23.12	23.36	23.53	23.72	23.88
	Social damage cost	(5)	3.60	2.40	1.80	1.44	1.19	1.04	0.90	0.79	0.72
	Total social cost	(6) = (4) + (5)	24.94	24.53	24.31	24.27	24.31	24.40	24.43	24.51	24.60
System with new nuclear-fueled plants	Abatement cost	(7)	0.30	0.39	0.26	0.29	0.30	0.39	0.39	0.30	0.37
	Generation and transmission cost	(8)	10.26	10.08	10.00	9.97	9.78	9.63	9.54	9.50	9.43
	Distribution cost	(9)	10.74	10.74	10.74	10.74	10.74	10.74	10.74	10.74	10.74
	Private cost	(10) = (7) + (8) + (9)	21.30	21.21	21.00	21.00	20.82	20.76	20.67	20.54	20.54
	Social damage cost	(11)	3.60	1.20	0.45	0	0	0	0	0	0
	Total social cost	(12) = (10) + (11)	24.90	22.41	21.45	21.00	20.82	20.76	20.67	20.54	20.54

Source: Table A.1 and References (*Anderson* (1975); (*Barrager* et al. (1976)).

Table A.3: **Long-Run Social Average Cost for Coal-Fired and Nuclear-Fueled Systems**

Peak load (MW)	1,000–1,500	1,500–2,000	2,000–2,500	2,500–3,000	3,000–3,500	3,500–4,000	4,000–4,500	4,500–5,000
Output level (10^9 kWh)	5,466–8,200	8,200–10,932	10,932–13,665	13,665–16,398	16,398–19,131	19,131–21,864	21,864–24,597	24,597–27,330
LRSMC System with new coal-fired plants	23.6	23.6	24.1	24.5	24.9	24.6	25.1	25.4
System with new nuclear-fueled plants	17.4	18.6	19.2	19.9	20.4	20.0	19.5	20.5

and plotted in Figure A.1 which shows higher LRSMC values for the coal-fired plants than for the nuclear-fueled plants.

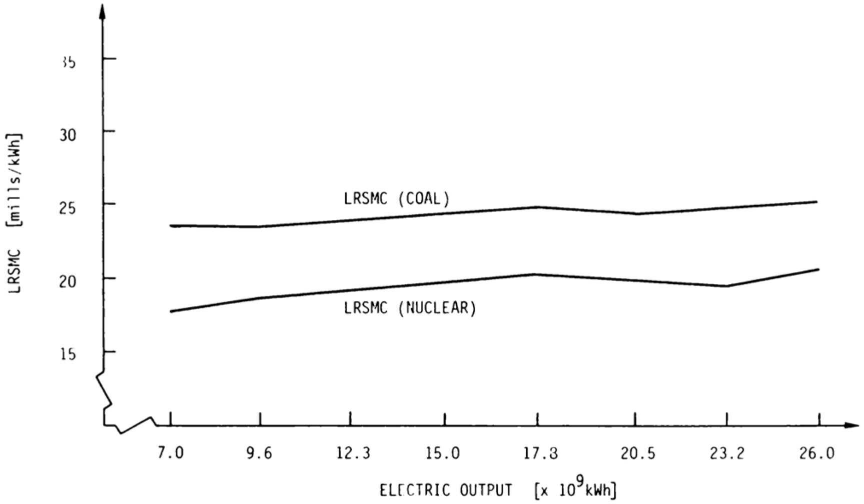

Fig. A.1: The Long Run Social Marginal Cost Curves of Two Types of New Steam Plants Operated by a System with 1000 MW Peak Load in 1970, Used Old Coal-Fired Plants in that Year (1975 Prices)*

* The LRSMC Curves connect the midpoints of the output intervals of Table A.3

Table A.3 shows the long-run social marginal costs for different new steam plants, operated by a 1,000 MW capacity system in 1970. The cost figures are given in 1975 prices.

Comparing the figures in Table A.3 with the one given point in the SRI study, we find that they have arrived at significantly higher absolute levels of LRSMC in their estimates:[3] and average of 36 mills/kWh for coal-fired systems, and 33,4 mills/kWh for the nuclear-fueled one.[4] This is also supported by Anderson's study.[5] His estimate for "long-run marginal cost" ranges between 27.1 mills/kWh and 58 mills/kWh in 1975 prices.

The SRI estimates cannot be used for computing the INSB resulting from the use of the new nuclear-fueled plants, since they do not provide the LRSMC curves. On the other hand, we cannot totally ignore them and rely solely on our estimated LRSMC curves, presented in Table A.3. The points of the second one will be calculated by add-

[3] The SRI research provides separate estimates for High-Sulfur-Coal plants, for Low-Sulfur-Coal plants, and for High-Sulfur-Coal plants with Flue Gas Desulfurization.

[4] This is a modified figure; it includes 10.7 mills/kWh distribution cost.

[5] He does not provide separate estimates for coal-fired plants, nuclear-fueled plants, and other types of electric power generation. Also, his estimates do not include the social damage cost, although this seems to be offset by choosing high abatement costs.

ing 10 mills/kWh to each point in Table A.3. Hence the second set of LRSMC curves will be parallel with, and 10 mills/kWh above the ones in the first set.

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