1. United States

PRIVATIZATION AND DEREGULATION
IN THE U.S. ELECTRIC POWER SECTOR

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Part 1. Historical Background and Evolution of the U.S. Electric Power Sector

I. Brief History of the System

The U.S. electricity system has been, and continues to be, a patchwork of state and federal regulations in a system with both private, municipal, and other government ownership. In this section we summarize the origin and early history of the public and private sector activities.

A. Private Sector Activities

The first decades of the electricity industry were marked by rapid technology innovation and chaotic institutional development. Private ownership of electricity systems broke out of small scale municipal structures when the system economies of large scale transmission began to be exploited in the period just before World War I. By linking together separate systems, load diversity improved the efficiency of power production. Small plants could be shut down and only the most productive equipment used. This saved fuel and maintenance cost, which more than offset the extra costs of transmission lines. Thus, geographic economies allowed for both lower rates and increased profits compared to more isolated operations. This example of pervasive network economies drove the early growth of the large scale electric utility beyond the confines of major metropolitan areas.

Scale economies could only be exploited systematically in a political regime that was stable enough to make raising capital feasible. The early history of competition in electricity was frequently destructive. Many private firms failed financially and were taken over by government entities. These seldom realized the scale economies that the larger private firms demonstrated. But the private firms faced a constant threat of franchise revocation by local political authorities. The political structure of state regulation with well-defined long term franchises began with the first commissions established in Wisconsin in 1906 and New York in 1907. By the 1920s over half the states had adopted this framework. Therefore, natural monopoly conditions could be exploited without undue political disruption. Jarrell (1978) gives an interesting account of the origins of the U.S. regulatory system for electricity.

With favorable conditions for growth, financing expansion became a key constraint. Electricity is a very capital intensive industry. Retained earnings were insufficient to finance expansion. The need for external capital became critical. The mass sale of common stock to customers during the 1920s and the broadening of debt markets beyond the New York financial community were crucial steps. At the same time equipment vendors also acquired a significant quantity of securities from utilities as payment for goods and services.

B. Government Ownership

Throughout the history of the U.S. electricity system there has been competition among various forms of ownership. The investor-ownership model became predominant, but not without several different kinds of government ownership achieving significant niche roles.
The federal government has played a significant, but always limited, role in electric power. Federal authority functions principally at the wholesale level. Constitutional authority over interstate commerce evolved into an apparatus of federal regulation covering most wholesale transactions. Moreover, the federal government has ownership rights over most hydroelectric resources. The Federal Water Power Act of 1920 established federal authority to issue licenses for non-federal hydroelectric development, to regulate prices for wholesale transactions, and embodied the principle of preferential allocation of surplus federal power sales to municipalities.

In the 1930s the federal government encouraged the growth of rural electricity service by subsidizing the formation of rural electric co-operatives. The Rural Electrification Administration (REA) provides loans, federal power preference and tax exemption to electric power organizations in rural areas and small towns. REA co-ops are also exempt from state and federal regulation. The value of the federal power preference grew with the expansion of Bureau of Reclamation dams in the western states. Hydroelectric construction by the federal government continued during World War II, and only slowed during the 1950s with a change in public policy and a lack of new major sites.

Municipal ownership of utilities seldom evolved into large systems. As cities grew they typically gravitated into the domain of the investor-owned sector. Municipal ownership had long provided a competitive constraint on the prices of private utilities. This constraint was limited by the municipality's opportunities to realize scale economies, which were largely determined by its geographical boundaries.

C. Balance between Public and Private Sectors

Throughout the post-war period the struggle between government ownership and the investor-owned segment continued. The election of Eisenhower in 1952 signalled the end of expansion of the federal system. Projects started previously were completed in the 1950s, but subsequent development stopped in the following decade. The public and co-operative segment continued to expand. The configuration of ownership structure in 1989 is illustrated in Table 1. This shows the dominant role of investor-owned firms. The small size of municipal and co-operative utilities is evident from either the average level of sales or capacity per utility. In terms of capacity, the average investor-owned firm in 1992 had 2042 MW, compared to 38 MW per publicly-owned utility and 30 MW per co-operative. A similar disproportion is evident by comparing average sales.

II. Characterization of the U.S. Electricity System
A. Fuel Use

The dominant fuel used for power generation in the U.S. is coal. Limited hydroelectric resources and growing concern about environmental impacts of coal-fired power plants led to an expansion of alternative fuels. The two main alternatives were nuclear and petroleum-based fuels. The first sizable contribution from nuclear power occurred in the late 1960s. In the fast growth
period of the 1950s and early 1960s, a large fraction of incremental capacity was fired by oil and natural gas. By 1970, before nuclear plants became a significant factor, oil and gas generation represented around 40% of all production (EEI).

The expanded uses of oil and gas fuel for power generation was economic until the oil price shocks of the 1970s. During this decade fuel related costs increased dramatically, making the need for substitutes apparent. Unfortunately, the principal solid fuel technologies, coal and nuclear, encountered substantial siting and construction delays just when they were needed most. By the early 1980s, projects based on these fuels came into operation and substantially reduced the share of oil and gas-fired generation. With the fall in world oil and gas prices starting in 1986, however, the shift to solid fuels may have been excessive. By 1992 only 13% of the fuel mix was oil and gas. However, the costs of most of the coal and nuclear plants were much higher than originally anticipated, and with the fall in world oil and gas prices starting in 1986, the shift to solid fuels was probably excessive.

Table 1. Structure of the U.S. Electricity Industry, 1992

<table>
<thead>
<tr>
<th>Type</th>
<th>Retail Sales (Thousand GWh)</th>
<th>Generation (Thousand GWh)</th>
<th>Surplus (Deficit) (Thousand GWh)</th>
<th>Number of Utilities</th>
<th>Capacity (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investor-owned</td>
<td>2112</td>
<td>2210</td>
<td>98</td>
<td>262</td>
<td>535</td>
</tr>
<tr>
<td>Publicly-owned</td>
<td>395</td>
<td>224</td>
<td>(171)</td>
<td>2017</td>
<td>76</td>
</tr>
<tr>
<td>Co-operative</td>
<td>207</td>
<td>140</td>
<td>(67)</td>
<td>943</td>
<td>28</td>
</tr>
<tr>
<td>Federal</td>
<td>49</td>
<td>252</td>
<td>203</td>
<td>10</td>
<td>63</td>
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</table>

Table 2. Capacity and Generation by Fuel Type, 1992

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Capacity (MW)</th>
<th>Capacity (%)</th>
<th>Generation (GWh)</th>
<th>Generation (%)</th>
</tr>
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<tbody>
<tr>
<td>Coal</td>
<td>300,547</td>
<td>43.2</td>
<td>1,575,895</td>
<td>56.3</td>
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<tr>
<td>Oil-Steam</td>
<td>44,472</td>
<td>6.4</td>
<td>86,046</td>
<td>3.1</td>
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<tr>
<td>Oil-Turbine</td>
<td>27,381</td>
<td>3.9</td>
<td>2,871</td>
<td>0.1</td>
</tr>
<tr>
<td>Gas-Steam</td>
<td>101,182</td>
<td>14.6</td>
<td>245,612</td>
<td>8.8</td>
</tr>
<tr>
<td>Gas-Turbine</td>
<td>26,910</td>
<td>3.9</td>
<td>18,260</td>
<td>0.7</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>93,375</td>
<td>13.4</td>
<td>239,559</td>
<td>8.6</td>
</tr>
<tr>
<td>Nuclear</td>
<td>98,985</td>
<td>14.2</td>
<td>618,776</td>
<td>22.1</td>
</tr>
<tr>
<td>Other</td>
<td>2,207</td>
<td>0.3</td>
<td>10,200</td>
<td>0.4</td>
</tr>
<tr>
<td>Total</td>
<td>695,059</td>
<td>100.0</td>
<td>2,797,219</td>
<td>100.0</td>
</tr>
</tbody>
</table>
B. Retail Rate Structures

Table 3 shows average prices per kWh for residential customers and for all customers sampled over five year intervals from 1930 to 1990 and the average rate of change of prices between the sample intervals. This table shows the striking long term decline in electricity prices, reflecting the productivity growth characterizing the industry up until the 1965-1970 time period. The rate of decline was greater for residential rates than for all customers, because, in part, residential prices started at much higher levels. The gap between residential and non-residential rates in the early 1900s is consistent with profit-maximizing behavior, which would have required low prices to induce industrial consumers to switch to electric power. Prior to World War II, average residential rates were about twice the average rate for all customers (which of course includes residential customers). The price increases, starting in the 1970-1975 period, were distributed less to residential customers than to other customer classes. When real electricity rates peaked around 1985, the average residential rate was less than 10% above the system average.

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential Rate (¢/kWh)</th>
<th>Residential Rate (1982¢/kWh)</th>
<th>Average Annual % Change</th>
<th>All Customers Rate (¢/kWh)</th>
<th>All Customers Rate (1982¢/kWh)</th>
<th>Average Annual % Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>1930</td>
<td>6.0</td>
<td>38.6</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>1935</td>
<td>5.0</td>
<td>37.3</td>
<td>-0.7</td>
<td>2.4</td>
<td>18.4</td>
<td>+1.4</td>
</tr>
<tr>
<td>1940</td>
<td>3.8</td>
<td>27.8</td>
<td>-5.8</td>
<td>2.0</td>
<td>14.9</td>
<td>-4.1</td>
</tr>
<tr>
<td>1945</td>
<td>3.5</td>
<td>18.1</td>
<td>-8.2</td>
<td>1.7</td>
<td>9.2</td>
<td>-9.2</td>
</tr>
<tr>
<td>1950</td>
<td>2.9</td>
<td>11.4</td>
<td>-8.9</td>
<td>1.7</td>
<td>7.2</td>
<td>-4.9</td>
</tr>
<tr>
<td>1955</td>
<td>2.7</td>
<td>9.3</td>
<td>-4.1</td>
<td>1.7</td>
<td>5.8</td>
<td>-4.0</td>
</tr>
<tr>
<td>1960</td>
<td>2.5</td>
<td>7.6</td>
<td>-3.9</td>
<td>1.6</td>
<td>5.2</td>
<td>-2.3</td>
</tr>
<tr>
<td>1965</td>
<td>2.3</td>
<td>6.4</td>
<td>-3.2</td>
<td>1.6</td>
<td>4.8</td>
<td>-1.6</td>
</tr>
<tr>
<td>1970</td>
<td>2.1</td>
<td>4.9</td>
<td>-5.2</td>
<td>1.6</td>
<td>3.9</td>
<td>-4.1</td>
</tr>
<tr>
<td>1975</td>
<td>3.2</td>
<td>5.4</td>
<td>+1.9</td>
<td>2.7</td>
<td>4.9</td>
<td>+4.7</td>
</tr>
<tr>
<td>1980</td>
<td>5.1</td>
<td>6.0</td>
<td>+2.0</td>
<td>4.5</td>
<td>5.4</td>
<td>+2.2</td>
</tr>
<tr>
<td>1985</td>
<td>7.4</td>
<td>6.7</td>
<td>+2.2</td>
<td>6.5</td>
<td>6.1</td>
<td>+2.2</td>
</tr>
<tr>
<td>1990</td>
<td>7.8</td>
<td>5.9</td>
<td>-2.5</td>
<td>6.6</td>
<td>5.1</td>
<td>-3.5</td>
</tr>
</tbody>
</table>

Although the rate making process is supposed to produce prices that are not discriminatory and are based on costs, there are clearly exceptions to these principles. Some states have explicit subsidy policies aimed usually at low-income residential customers, sometimes at all
residential customers. More often, subsidies are implicit. Agricultural customers frequently pay low prices that are difficult to justify on a cost basis. Economic development arguments are sometimes used to rationalize low prices to specific industries, or to specific geographic regions. Table 4 below summarizes average electricity costs for 1992 by customer type for the four main ownership structures.

Table 4
Average Revenue (¢ per kWh) by Class of Ownership and by Sector, 1992

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investor-Owned</td>
<td>8.6</td>
<td>7.8</td>
<td>5.0</td>
<td>7.1</td>
</tr>
<tr>
<td>Publicly-Owned</td>
<td>6.6</td>
<td>6.6</td>
<td>4.8</td>
<td>6.0</td>
</tr>
<tr>
<td>Co-operative</td>
<td>7.7</td>
<td>7.4</td>
<td>4.7</td>
<td>7.0</td>
</tr>
<tr>
<td>Federal</td>
<td>5.8</td>
<td>6.1</td>
<td>2.7</td>
<td>2.6</td>
</tr>
<tr>
<td>Average</td>
<td>8.2</td>
<td>7.7</td>
<td>4.8</td>
<td>6.8</td>
</tr>
</tbody>
</table>

This table shows the different rate policies and average costs of the investor-owned segment, the publicly-owned segment, co-operatives and the federal government. Because government-owned utilities pay no taxes and have no equity capital, their rates should be lower than investor-owned firms. There are also significant operating subsidies from the federal sector to the municipal and co-operative segments. As Table 1 indicated, federal power sales to ultimate customers are small. Most federal sales are preferential allocations of hydroelectric generation at very low cost. This explains why the average rate for federal power is lower than all rates to end-use customer classes. Despite these price differences, studies of the relative efficiency of government versus investor-owned electric utilities have detected no significant differences (Atkinson and Halvorsen, 1986).

Table 4 also indicates a tendency toward price discrimination against commercial customers. For both publicly-owned and federal rates these customers pay the highest prices. For investor-owned and co-operative firms residential rates are somewhat higher than commercial. The differentials, however, are too small to be based entirely on cost. The typically higher voltages and higher load density of commercial as opposed to residential customers would suggest bigger price spreads. In all likelihood, the commercial customers rates are more determined by their relative bargaining weakness compared to the political power of residential customers. Industrial customers wield economic power because they can shift production to regions with lower costs and, in some cases, they can generate their own power requirements.

C. Investment Behavior

Mismatches between supply and demand were particularly severe during the 1970s and
1980s as the size of generating units grew and construction lead time lengthened. At first, the issue was potential capacity deficiencies. During the 1970s, the requirements for environmental review of power plant construction became much greater than they had been previously. Repeated changes in safety requirements, particularly following the accident at Three Mile Island in 1979, lengthened construction and added to its cost. The oil price shock of 1973-74 made the economics of coal and nuclear power projects more attractive, but the contemporaneous rate increases also reduced demand growth. By the late 1970s, short-run marginal costs were high, reserve margins were low, and the backlog of large-scale construction projects was substantial.

This process reversed in the 1980s. Oil prices began a gradual decline. A severe economic recession reduced demand growth. Utilities began to cancel plans for capacity expansion. In the 1972-1974 period utilities ordered 107 nuclear plants. Between 1975 and 1978, 38 were canceled and another 48 were canceled in the 1979-1982 period (EIA, 1983). Despite these efforts to adjust supply, there was substantial excess capacity during the mid-1980s. The cost disallowances described briefly in Section III were based in part upon excess capacity considerations.

Table 5 shows the growth in capacity and demand for the period 1966-1990, and their consequences for reserve margin. Reserve margin is used as the best single summary statistic measuring the adequacy of capacity relative to demand. A conventional industry rule of thumb for reserve margin (measured as the percentage of capacity above peak demand) is 20%. This is often related to some probabilistic measure of outage risk, but the appropriate outage risk level is usually specified by convention, rather than by economic criteria. The Table 5 data are at the aggregate national level. The non-coincident peak means just the sum of the highest demands, regardless of when during the year it occurred. As such, these data conceal regional variations, and probably understate effective reserves, due to potential capacity sharing when peak loads occur at different times. Table 5 clearly shows the excess capacity period from 1975-1990.

Table 5. Aggregate Capacity and Peak Demand Growth and Reserve Margins

<table>
<thead>
<tr>
<th>Period</th>
<th>Capacity Growth Rate (%)</th>
<th>Demand Growth (%)</th>
<th>Average Reserve Margin (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1966-1970</td>
<td>6.4</td>
<td>6.2</td>
<td>18.5</td>
</tr>
<tr>
<td>1971-1975</td>
<td>6.2</td>
<td>4.0</td>
<td>24.6</td>
</tr>
<tr>
<td>1976-1980</td>
<td>2.7</td>
<td>3.3</td>
<td>33.2</td>
</tr>
<tr>
<td>1981-1985</td>
<td>1.6</td>
<td>1.4</td>
<td>36.2</td>
</tr>
<tr>
<td>1986-1990</td>
<td>1.1</td>
<td>3.1</td>
<td>29.2</td>
</tr>
</tbody>
</table>

Table 6 gives aggregate data on the capital expenditures of the investor-owned segment from 1973-1990. The tremendous inertia of the commitment to nuclear power is indicated by
comparing this data with Table 5. At the very time when price induced declines in demand were increasing excess capacity, the capital budget of the industry was escalating substantially.

The Table 6 data are also interesting in the more recent period. The rapid decline in generation sector investment explains most of the decline in total construction. The only offsetting effect is an increase in distribution system investment, which increases by 40% from 1983 to 1990. These data suggest that while the vertically integrated firms are losing control of the generation segment (see Part 3), they are relatively free to shift investment attention to the distribution segment, which is free from competitive pressures. There is no incentive to increase transmission investment because it would inevitably end up strengthening the competitive position of independent generators seeking wider markets.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Construction</th>
<th>Generation</th>
<th>Transmission</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>1973</td>
<td>31.0</td>
<td>17.4</td>
<td>3.9</td>
<td>7.3</td>
</tr>
<tr>
<td>1974</td>
<td>31.8</td>
<td>18.7</td>
<td>3.9</td>
<td>6.7</td>
</tr>
<tr>
<td>1975</td>
<td>27.3</td>
<td>17.0</td>
<td>3.0</td>
<td>5.2</td>
</tr>
<tr>
<td>1976</td>
<td>29.2</td>
<td>19.1</td>
<td>2.9</td>
<td>4.7</td>
</tr>
<tr>
<td>1977</td>
<td>32.2</td>
<td>21.8</td>
<td>2.6</td>
<td>5.1</td>
</tr>
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<td>1978</td>
<td>33.8</td>
<td>22.7</td>
<td>2.4</td>
<td>5.5</td>
</tr>
<tr>
<td>1979</td>
<td>34.7</td>
<td>23.7</td>
<td>2.7</td>
<td>5.6</td>
</tr>
<tr>
<td>1980</td>
<td>33.0</td>
<td>22.4</td>
<td>2.7</td>
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<td>32.7</td>
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<td>1982</td>
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<td>25.3</td>
<td>2.2</td>
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<td>1984</td>
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<td>28.0</td>
<td>19.3</td>
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<td>1987</td>
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<td>1988</td>
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<td>1990</td>
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<td>6.6</td>
<td>1.8</td>
<td>6.8</td>
</tr>
</tbody>
</table>
III. Political Economy of Regulation
A. Dominance of the Investor-Owned Model

Within the organizational variety in the electricity industry, the investor-owned firm, subject to state regulation, emerged as the dominant model, and remains so today. Unlike most other industrial countries, the U.S. electricity industry was never nationalized. It is not entirely clear why this is the case. Clearly, the strong judicial system in the U.S. and the constitutional commitment to the enforcement of property rights prevents conversion of private property to public use without fair compensation. Yet nationalization of electric power has occurred in other countries with strong property rights (such as the United Kingdom and France). Two hypotheses suggest themselves, however; these are (1) geographical diffusion (the “wide-open spaces” theory), and (2) the relative lack of devastating destruction (the “no land wars” theory).

The geographical argument has both a technological and an institutional dimension. A nationalized industry would be operated in some sense as a single system. Whether this means “single area dispatch” or a national grid is unclear. But a nationalized system would have a central locus of decision-making that could be expected to be in the political capital of the nation state. The determination of standards and practices would emanate from such a center, with relatively little input from provincial interests. The U.S. history of localism in political decision-making is not consistent with a national scale model. Political struggles over the balance of power in the federal system are endemic in U.S. history.

Typically, it is national crises which have accelerated the centralization of political power. Indeed, the economic problems of the 1930s had this effect to a certain degree in the U.S. The federal role in hydroelectric power development grew to be an important force during this period. But even these activities had a distinctly regional character. Federal agencies created for power development and marketing were dedicated to regional economic development mandates. The municipal preference for federal power helped improve the competitive position of public utilities vis-à-vis investor-owned firms. But by propping up these small entities, the federal government was curtailing the consolidation of the industry into larger and larger units.

Consolidation did occur in the investor-owned segment of the industry, but there was less than could be justified on the basis of economies of scale. Table 7 shows the number of firms operating in certain individual states during the period 1938-1968, as well as national totals. The rate of consolidation appeared to have slowed after the 1950s. Christensen and Green (1976), using data from the 1970s estimate a statistical model indicating that economies of scale at the firm level were not completely exploited until firms reach a capacity of 4,000 MW. Joskow and Schmalensee (1983) raise questions about the validity of such estimates, but still accept the notion that unexploited scale economies are prevalent at the firm level (as opposed to the plant level). The source of these firm level economies has not been clearly identified, but appears to lie in multi-plant coordination to meet demand fluctuations. Accepting the notion that firm level economies exist at least up to the level of 4,000 MW implies that most U.S. electric utilities are too small.
Table 7. Number of Investor-Owned Firms

<table>
<thead>
<tr>
<th>State</th>
<th>1938</th>
<th>1948</th>
<th>1958</th>
<th>1968</th>
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<td>California</td>
<td>8</td>
<td>7</td>
<td>5</td>
<td>3</td>
</tr>
<tr>
<td>Illinois</td>
<td>16</td>
<td>16</td>
<td>9</td>
<td>8</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>43</td>
<td>36</td>
<td>25</td>
<td>16</td>
</tr>
<tr>
<td>New Jersey</td>
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</tr>
<tr>
<td>National Total</td>
<td>412</td>
<td>321</td>
<td>265</td>
<td>236</td>
</tr>
</tbody>
</table>

B. Productivity Stagnation and Its Consequences

The U.S. regulatory system functioned smoothly during the post-WWII period as long as productivity increases continued. When these stagnated and began to reverse themselves in the 1970s and early 1980s, the system came under strain. Joskow (1987) is a good summary of these effects. The regulatory response to these conditions was a variety of experiments. We give a brief overview of these experiments, some of which will be examined in more detail below.

The locus of productivity problems in electricity was in new generating capacity. Initially the problem had its origin in the increased stringency of environmental regulation. The Clean Air Act and the requirements of the National Environmental Policy Act raised the cost of new power plants by requiring extensive review of the impact of new facilities and imposing mitigation costs. Increasingly stringent environmental regulation also affected nuclear power. Following the Three Mile Island accident of 1979 increased safety regulation required considerable extra work on a large number of plants under construction. The high interest rates during this period, slow growth, and management inefficiency also had negative impacts on construction costs. When plants entered commercial operation in the early 1980s, their nominal dollar costs were frequently 5 to 10 times higher than original estimates.

Standard regulatory practice in the U.S. defers including new plant costs in rates until commercial operation. Then, the costs are placed into “rate base” and become part of the total cost of service to be recovered in rates. A crucial step in this process is the determination that the costs were prudently incurred and that the projects are “used and useful.” The large costs of nuclear power projects focused more attention on these questions than they had previously received. State commissions refused to accept all costs. Disallowances in the range of 10-40% became frequent during the 1983-1987 period. The total disallowance has been estimated at $10 billion (ORNL, 1987, 1989). Sometimes the rationale for disallowance was “imprudence;” sometimes it was
excess capacity. In the latter case, the utility would eventually recover some of the costs as demand increased.

The disallowance experience (which was not confined to nuclear plants) created strong incentive effects. Utilities that were punished financially had a disincentive for investment. Regulators, disappointed with the performance of firms, developed a more activist stance regarding alternative resource strategies. A number of state jurisdictions implemented performance incentive schemes for baseload power plants. Joskow and Schmalensee (1986) found that these were the dominant type of incentive mechanism adopted in the U.S. electricity industry. The productivity of capital intensive baseload power plants depends considerably on their level of output. Through a system of rewards and penalties, regulators hoped to induce good performance and lower overall cost. The effect of these incentives is doubtful. Berg and Jeong (1991) studied these programs. They find that a measure of cost inefficiency is a good predictor of the agency’s decision to adopt incentive mechanisms. Unfortunately, they find that firm efficiency does not improve due to these mechanisms. Presumably such results, if correct, occur because the incentive is limited to only part of the firms’ behavior and not all of it.

C. The Political Economy of Deregulation

The first steps toward deregulation in the U.S., the passage of the PURPA legislation and its implementation, were taken as a response to the problems of the nuclear power industry. Vigorous growth of the private power industry created constituencies that lobbied for the expansion of this sector at the expense of the investor-owned firms. This process eventually contributed to the passage of the Energy Policy Act of 1992 (discussed at greater length in Part 3), which substantially expanded the rights of these producers.

These transformations were constrained to occur with no major disruption to existing stakeholders. Asset write-downs were limited, bankruptcies few. The contrast with drastic government intervention in other countries, however, is remarkable. Nationalization as a remedy of last resort is virtually absent from political discussion of the problems and solutions proposed for the electricity sector. The highly fragmented industry structure makes any kind of nationalization a formidable political and administrative task. It also limits the ability to achieve rapid, large-scale privatization.

Part 2. Competitive Bidding and Independent Power

I. Introduction

The creation of an unregulated independent power industry in the U.S. began incrementally, and without explicit central policy design, as a result of a number of separate legal, regulatory and economic changes. The major watershed event was the passage of the Public Utilities Regulatory Policies Act (PURPA) of 1978. PURPA created a class of private suppliers, called Qualifying Facilities (QFs) that were exempt from profit regulation and entitled to sell their
output to franchised utilities. In some states, the terms of purchase were so attractive that development of QF capacity overwhelmed expectations. In response, utilities and regulators sought mechanisms to ration the supply efficiently. The result was a competitive bidding process for long term power sales contracts. This mechanism has proved to be sufficiently flexible and attractive to both buyers and sellers, that it has been broadened to include a new classes of suppliers; first, Independent Power Producers (IPPs), more recently Exempt Wholesale Generators (EWGs). Together these new entrants are expected to sustain a significant share of the market for new generating capacity. In this part we describe the background and development of the private power industry and characterize its current state.

II. The Public Utilities Regulatory Policies Act of 1978

PURPA opened the door to competitively supplied power in the U.S., but with considerable restrictions. Under PURPA, a Qualifying Facility could have production capacity of no more than 50 Megawatts, unless it used either renewable fuels or cogeneration, the combined production of useful heat and power in a single process. Although PURPA legislation set a general framework for QF development, implementation was delegated to state regulatory commissions. FERC was mandated to write rules that state commissions had to follow in their deliberations. The two irreducible requirements of the legislation and FERC rules were the obligation placed upon utilities to purchase QF output, and the avoided cost concept as the guide to determining the purchase price. In this section we review these issues.

The primary obligation PURPA placed on utilities was the requirement to purchase QF output. Absent such an obligation, private suppliers had little or no bargaining power with the utility. Prior to PURPA, some utilities did purchase a minor amount of private power, principally from industrial self-generators selling excess production. PURPA required that all utilities create a tariff under which they would purchase from QFs (tariffs were also required for back-up and related services from the utility). The FERC rules also allowed for long term purchase contracts between utilities and QFs, but did not require these.

In practice, the difference between tariff and contract turned out to be decisive. Private investors were reluctant to support projects whose revenue was based on revisable tariffs. Because many projects were financed on a “stand-alone” basis, long term pricing certainty was necessary to support the project’s credit (Kahn, Ch.6, 1988). In states where regulators were sympathetic to QF development, utilities were encouraged or required to make available long term contracts. These contracts typically had standard language which defined mutual relationships explicitly, or at least substantially narrowed the room for negotiation. The availability of standard contracts frequently made all the difference with regard to development. For example, the staff of the New Jersey Board of Public Utilities found that when tariffs only were offered, the response was minimal. When long term contracts were offered, the response was substantial (NJ BPU, 1986).

The need for long term contracts to stimulate investment in private power is probably due in part to the immobility of generating assets. The obligation to purchase is limited to the utility
serving the region in which the QF is located. Transmission access has been quite limited, so QFs have very little ability to seek buyers other than the monopsony utility. Wholesale transactions have been generally limited to inter-utility exchanges, up to the passage of the Energy Policy Act of 1992 (see Part 3 below). Therefore, since the utility is a monopsony buyer, and can potentially limit or manipulate over time a revisable QF tariff price, the seller needs a long term contract with fixed prices to limit opportunism. The alternative would be to finance relying only on a tariff. This approach would require much more equity than has been typical of project finance supported by long term contracts. Since equity is much more expensive than debt, such projects would be less profitable.

PURPA defined the pricing rule in both the long and short run using the notion of avoided cost. The fundamental idea underlying the avoided cost concept was that ratepayers should be indifferent to QF purchases. This meant that any economic rent accruing from QF efficiency would flow to the private producers, not utility ratepayers. State implementation of the avoided cost concept focused on the substantial practical problems of estimating what constituted ratepayer indifference.

The distinction between avoided energy and avoided capacity costs is basic. The former is appropriately measured considering the operations and dispatch of the power system (see, for example, Jabbour, 1986). The latter is essentially a reliability issue; capacity costs are incurred to reduce the probability that shortages will occur. Where utilities had excess capacity, avoided costs were predominantly associated with energy. Where utilities had capacity requirements, both terms had to be considered, commonly in a framework that examined a wide range of generation technology options. In practice, utilities and state commissions negotiated estimates of avoided cost. The boundaries of these negotiations could be broad, requiring compromises between precision and ease of estimations.

Seen broadly, the avoided cost dialogue is part of the “cost unbundling” process in which the underlying cost structure of the firm gets examined with increasing sophistication and depth. Cost unbundling is common in regulated industries under competitive pressure (Bailey, 1986). What is different in this case is that a competitive fringe of firms audits the costs of the incumbent by litigation in regulatory proceedings. The advantage of this arrangement is that the regulatory process can compel disclosure that otherwise would not occur. The disadvantage is that the competitors are seeking economic rents in their use of the regulatory process, so their auditing function is not necessarily unbiased. This process, in both its positive and negative aspects, is illustrated by the litigation in California over short-run avoided energy cost payments (Kahn, 1995).

III. Competitive Bidding for Private Power

Competitive bidding for long term contracts emerged as a successor to the “first-come/first served” rationing mechanism associated with standard offers. The bid evaluation process requires complex trade-offs. Proposed projects differ by their fuel type, level of
development, location in the transmission network, environmental effects, and operational flexibility, as well as price. Since it is difficult to compare all of these attributes with a common metric, it is inevitable that qualitative judgment will play a role in the evaluation process.

Competitive bidding brought product differentiation to the independent power market. One important dimension for this involved operational flexibility. The PURPA obligation to purchase QF power meant that all such production was “must take” in nature. A number of factors, however, led to increasing operational problems on power systems, especially during “off-peak” period. The fundamental problems is an excess of inflexible generation at these times, relative to demand (Le, et al., 1991). Thus, the demand for more flexible operation became great, and utilities began to require this in their requests for bids. Analytic problems associated with bid evaluation in this setting are described in Kahn et al. (1992).

One of the principal motivations for competitive bidding is to lower the cost of power. Although evidence is fragmentary, there is reason to believe that prices are coming down. Table 8, from Comnes, Belden, and Kahn (1995), shows for a small sample of projects that prices are getting lower over time. These data are not without ambiguity, and require some discussion. Further, there are a variety of non-price terms which affect the overall value of the projects. The non-price terms involve either operational flexibilities or contractual performance requirements. Broadly speaking, the more recent projects offer the utilities more operating freedom and stricter contract terms. Kahn (1991) gives an account of the trend toward stricter contract terms. A brief explanation of the Table 8 data should make clear the extent to which clear conclusions are possible.

The data given in Table 8 is denominated in levelized nominal 1994$ over the contract term which is at least 20 years in length. This sample represents roughly one sixth of the private power projects that entered service during the 1990-93 period, but most of that was based on standard offer contracts. This sample represents at least half of the projects acquired by some kind of competitive process. Within this sample, the coal-fired projects are an average 2.49B/kWh, or 35%, more expensive than the gas-fired projects. In quantity terms, gas clearly dominates the market.

Broadly speaking, the coal-fired projects represent avoided cost expectations that were higher than subsequent developments proved to be justified. The dominance of gas fired generation was due both to falling commodity costs for fuel and the rapid introduction of highly efficient combined cycle technology based on advanced combustion turbines. This technology has relatively modest capital costs and thermal efficiencies that exceed 45% (Beck, 1993).

These data are not conclusive. The number of cases reviewed is small. The productivity gains reflected in Table 8 may be generic to the industry, rather than due to the superior performance of the private producers. Even if this latter hypothesis is correct, however, some of the stimulus for these gains can be attributed to competitive pressure.

Private power production offers incentives for technical innovation that are absent from rate of return regulation. Under the fixed price formulas contained in private power contracts, any
Table 8. Prices of Private Power Projects

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Project Name</th>
<th>Contract Capacity (MW)</th>
<th>Capacity $/kW-yr</th>
<th>Energy $/kWh</th>
<th>Total 80% cf $/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>Indiantown Cogen</td>
<td>300</td>
<td>351</td>
<td>0.035</td>
<td>0.085</td>
</tr>
<tr>
<td></td>
<td>Chambers (Carneys Point)</td>
<td>184</td>
<td>324</td>
<td>0.042</td>
<td>0.088</td>
</tr>
<tr>
<td></td>
<td>Crown Vista</td>
<td>100</td>
<td>523</td>
<td>0.029</td>
<td>0.104</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td></td>
<td></td>
<td>0.035</td>
<td>0.092</td>
</tr>
<tr>
<td>Gas</td>
<td>Hermiston</td>
<td>409</td>
<td>181</td>
<td>0.020</td>
<td>0.045</td>
</tr>
<tr>
<td></td>
<td>Independence</td>
<td>740</td>
<td>43</td>
<td>0.049</td>
<td>0.055</td>
</tr>
<tr>
<td></td>
<td>Hopewell Cogen</td>
<td>248</td>
<td>150</td>
<td>0.035</td>
<td>0.056</td>
</tr>
<tr>
<td></td>
<td>Richmond Power Ent./Sj E Cogen</td>
<td>210</td>
<td>145</td>
<td>0.036</td>
<td>0.057</td>
</tr>
<tr>
<td></td>
<td>Doswell</td>
<td>600</td>
<td>171</td>
<td>0.033</td>
<td>0.057</td>
</tr>
<tr>
<td></td>
<td>North Las Vegas</td>
<td>45</td>
<td>199</td>
<td>0.030</td>
<td>0.058</td>
</tr>
<tr>
<td></td>
<td>Spanaway (Pierce Co., Wa.)</td>
<td>240</td>
<td></td>
<td>0.020</td>
<td>0.060</td>
</tr>
<tr>
<td></td>
<td>Gordonsville/Turbo Power I and II</td>
<td>100</td>
<td>128</td>
<td>0.045</td>
<td>0.064</td>
</tr>
<tr>
<td></td>
<td>Panda</td>
<td>165</td>
<td>160</td>
<td>0.042</td>
<td>0.065</td>
</tr>
<tr>
<td></td>
<td>Brooklyn Navy Yard Central</td>
<td>90</td>
<td>254</td>
<td>0.031</td>
<td>0.067</td>
</tr>
<tr>
<td></td>
<td>Tiger Bay</td>
<td>217</td>
<td>299</td>
<td>0.028</td>
<td>0.070</td>
</tr>
<tr>
<td></td>
<td>Blue Mountain Power</td>
<td>150</td>
<td>338</td>
<td>0.022</td>
<td>0.070</td>
</tr>
<tr>
<td></td>
<td>Wallkill</td>
<td>95</td>
<td>269</td>
<td>0.034</td>
<td>0.072</td>
</tr>
<tr>
<td></td>
<td>Brooklyn Navy Yard B</td>
<td>40</td>
<td>277</td>
<td>0.036</td>
<td>0.075</td>
</tr>
<tr>
<td></td>
<td>Brooklyn Navy Yard A</td>
<td>40</td>
<td>278</td>
<td>0.036</td>
<td>0.076</td>
</tr>
<tr>
<td></td>
<td>Linden</td>
<td>594</td>
<td>266</td>
<td>0.041</td>
<td>0.079</td>
</tr>
<tr>
<td></td>
<td>Pedrickstown</td>
<td>106</td>
<td>234</td>
<td>0.050</td>
<td>0.083</td>
</tr>
<tr>
<td></td>
<td>Holtsville</td>
<td>136</td>
<td>251</td>
<td>0.050</td>
<td>0.085</td>
</tr>
<tr>
<td></td>
<td>Dartmouth, Mass.</td>
<td>68</td>
<td>405</td>
<td>0.028</td>
<td>0.085</td>
</tr>
<tr>
<td></td>
<td>Enron</td>
<td>83</td>
<td>520</td>
<td>0.020</td>
<td>0.094</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td></td>
<td></td>
<td>0.035</td>
<td>0.069</td>
</tr>
<tr>
<td>Peaker</td>
<td>Hartwell</td>
<td>303</td>
<td>90</td>
<td>0.038</td>
<td>0.051</td>
</tr>
<tr>
<td></td>
<td>Commonwealth Atlantic</td>
<td>312</td>
<td>68</td>
<td>0.052</td>
<td>0.061</td>
</tr>
<tr>
<td></td>
<td>Average</td>
<td></td>
<td></td>
<td>0.045</td>
<td>0.056</td>
</tr>
<tr>
<td>Wind</td>
<td>Franklin &amp; Somerset Co. ME</td>
<td>20</td>
<td></td>
<td></td>
<td>0.056*</td>
</tr>
</tbody>
</table>

* 36% cf
cost-reducing technology adopted by the supplier adds to profit. The private producer also takes the risk that the innovation adopted will not perform as expected. Regulated firms, on the other hand, must pass all production economies realized through innovation through to ratepayers. They do not contribute to profit. When the outcome of adopting new technology is not favorable, the regulated firm may also be denied cost recovery by the regulator (Zimmerman, 1988). These incentives may combine to bias the regulated firm away from risky new technology, while leaving the private firm neutral.

There was a significant record of new technology adoption by the private power industry during the 1980s and 1990s. In addition to the rapid deployment of advanced gas-fired combined cycle technology described above, there was innovation in other areas as well. The first steam-injected gas turbine (STIG) was installed by a California paper mill subject to stringent air pollution control requirements (Kolp and Moeller, 1988). The adoption of circulating fluidized bed (CFB) coal combustion was also substantially more widespread in the private power section than among regulated or government-owned utilities (Grahame, 1990). In the area of renewable energy, the solar thermal technology of Luz International was commercialized through private power contracts. Table 8 shows that new wind turbine technology has very competitive prices for energy. Even when the intermittent nature of the output is taken into account, the prices compare favorably with conventional power production (Comnes, Belden and Kahn, 1995). While none of this evidence conclusively proves that more innovation will occur under private power than under a regime of regulation, it is clearly suggestive.

IV. The Emergence of Federal Competition Policy

Although the private power segment of the U.S. electricity market was almost nonexistent before 1980, by 1992 independent power producers accounted for 10.7% of all electricity sales. Regional differences in policy and resource opportunities contributed to a large variation in private power development across states. Table 9 gives selected regional data, showing primarily those states with larger shares of NUG generation. These eight states account for 61% of total independent generation in the U.S.

The unexpectedly large developments following PURPA stimulated a dialogue on the role of competition in electricity generation. This dialogue emerged in 1988 when FERC issued three Notices of Proposed Rulemaking (NOPRs) that addressed the commission's perceptions of appropriate reforms of the PURPA framework. Although these did not result in any explicit rule changes, they signalled a new interest in competitive mechanisms.

FERC subsequently approved a number of wholesale transactions involving non-QF suppliers based on market prices. The precise characterization of when a transaction qualifies for such pricing was subject to case law definition (Tenenbaum and Henderson, 1991). FERC activity in merger cases also showed a strong concern for competitive effects. As a condition for approving the merger of Pacific Power and Light with Utah Power and Light, specific transmission access conditions were required for third-party sellers.
Table 9. Selected Data on Independent Generation (1992)

<table>
<thead>
<tr>
<th></th>
<th>Independent Generation (million kWh)</th>
<th>Sales (million kWh)</th>
<th>Independent Share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>California</td>
<td>59.3</td>
<td>213.4</td>
<td>27.8</td>
</tr>
<tr>
<td>Florida</td>
<td>10.3</td>
<td>147.0</td>
<td>7.0</td>
</tr>
<tr>
<td>Louisiana</td>
<td>18.7</td>
<td>65.1</td>
<td>28.7</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>7.5</td>
<td>45.0</td>
<td>16.7</td>
</tr>
<tr>
<td>New Jersey</td>
<td>12.8</td>
<td>63.1</td>
<td>20.3</td>
</tr>
<tr>
<td>New York</td>
<td>14.1</td>
<td>128.5</td>
<td>11.0</td>
</tr>
<tr>
<td>Texas</td>
<td>51.6</td>
<td>239.4</td>
<td>21.5</td>
</tr>
<tr>
<td>Virginia</td>
<td>7.7</td>
<td>76.5</td>
<td>10.0</td>
</tr>
<tr>
<td>U.S. Total</td>
<td>296.0</td>
<td>2763.3</td>
<td>10.7</td>
</tr>
</tbody>
</table>

In 1992, the policy agenda shifted to the legislative arena. The Energy Policy Act created a new class of private producers as part of a change in federal regulation under the Securities Exchange Commission. The transmission access questions were also addressed in this legislation, but in ways that will take time to assess.

Part 3. Implications of an Open Access Regime

I. Introduction: The Energy Policy Act

The Energy Policy Act (EPAct) of 1992 has opened the door to significant change in wholesale competition by greatly extending the powers of the Federal Energy Regulatory Commission to mandate transmission access. Prior to this Act, the FERC was prevented from mandating transmission access that interfered with existing competitive relationships. This has now changed. EPAct gives the FERC authority to mandate transmission access if

1. voluntary negotiations have been conducted by the requesting entity and transmission owner for 60 days;
2. the order would be in the public interest;
3. reliability of all utility systems affected by the order would be maintained;
4. third-party wheeling is not subsidized by utility's existing customers.

If the FERC has the objective of promoting wholesale transmission access, it appears that
it will now have broad power to do so. The powers do not extend to transmission access at the retail level. There is substantial controversy in the U.S. over the issue of competition for end-use customers. Although some erosion of the franchised monopoly in distribution is likely to occur, for the most part there is a resistance to introducing retail competition on a wide scale, as is scheduled to occur in the British electric power market.

II. Transmission Pricing

The liberalization of wholesale trade represented by EPAct increases the importance of transmission pricing policy. FERC is considering a broad range of options, which we summarize here. The three approaches that we outline represent a different approach to the role of regulation and the structure of inter-firm relations.

A. Regional Transmission Groups - Reciprocal Voluntary Arrangements

There is a long tradition of reciprocal voluntary transmission arrangements in segments of the U.S. electricity industry. In its most elaborated form, these arrangements underlie the fully integrated power pools that operate principally in the Northeastern region. For a pooling arrangement to work, the members must be able to exchange power freely over the combined network of transmission facilities. Where the pool does central dispatch of the combined generation resources, fully reciprocal use of the combined transmission network occurs.

There are looser pooling arrangements which do not involve central dispatch. In these, some form of reciprocal transmission arrangement is also necessary, but the mutual commitment is less than in the fully integrated case. “Loose” pools commonly operate a kind of brokerage service, where parties post willingness-to-buy and willingness-to-sell offers, but transactions occur through bilateral arrangement. Power pooling institutions in the United States are surveyed in FERC (1981).

The limiting cases of reciprocity are bilateral agreements to exchange transmission services and emergency support involving commitments among many participants in a transmission network. In the latter case, the agreements are only for extraordinary circumstances where reliability is involved. Such arrangements are nearly ubiquitous. Typically the prices charged for emergency support are higher than the prices charged for routine firm and non-firm transmission services.

In principle, reciprocal voluntary arrangements might operate under the Energy Policy Act by offering transmission service within the framework of regional transmission groups (RTGs). These arrangements would be voluntary, although it is likely that they would be constrained by a constitution governing the policies of the group. There is considerable uncertainty about how and under what conditions concerning access to facilities such accommodation might or might not be achieved.

The limiting case, where an RTG developed a costing approach for transmission access that would be based on regional implementation of avoided-cost principles. This would require the
The following elements.

(i) A transmission resource plan (TRP)

The correct cost for transmission access is the incremental cost that a user imposes on a system. This requires an assessment of the impact that a user’s demand for access would have on the current cost-minimizing plan for constructing and maintaining adequate transmission capacity to meet the needs of its members. This, in turn, requires the development of a resource plan that is accepted by the RTG members.

(ii) A cost model for the TRP

The preferred TRP would depend on the needs of the Group members, and on the costs of satisfying those needs. This requires the development of a transmission costing model. Such a model would compute the total present-value cost of building and maintaining a desired transmission configuration. Given the economies of scale and interdependencies of transmission costs, it is unlikely that an algorithm could be devised that would choose the optimal plan for the members’ needs. Instead, several scenarios would have to be specified and the RTG would have to narrow the search done to those plans that are most cost-effective. Finding the optimal scenario would be an iterative process. Iteration would be necessary to investigate the cost consequences of different plans. An additional complication is that users demands for transmission services depend on their costs. Therefore, the optimal resource plan would have to be an iterated process so that demands are consistent with the cost of the resources that are made available.

(iii) The incremental cost of additional demand for transmission services

If a transmission system has adequate capacity to meet all demand in the foreseeable future, the economic cost of transmission is only the cost of line losses and other operating costs that are directly attributable to a user’s demands. If the system does not have adequate capacity, the economic cost of transmission includes the present-value of additional investment that must be incurred in order to provide the service. This is the same principle that governs the determination of avoided generation costs.

To estimate a transmission user’s capacity cost, it would be necessary to evaluate the change that the user’s demand imposes on the present-value cost of meeting all users’ transmission needs. Although the principle is identical to the principle of avoided generation capacity costs, this is a more complicated calculation because the cost is likely to depend on the size and the location of the transmission user’s demands. Qualitatively, if $T$ is a vector of all the transmission services that are anticipated in the RTG’s optimal resource plan, and if $t_{ij}$ is transmission demand of an individual user, the capacity cost of the transmission service is

$$c(t_{ij}) = C(T + t_{ij}) - C(T),$$
where $C(\bullet)$ is the cost of the optimal resource plan corresponding to the desired services.

(iv) Allocating fixed costs

The above discussion focuses on allocating costs that are incremental to the use of transmission services. Allocating the fixed costs of transmission -- costs that are not sensitive to demand, is also required. An RTG could have wide latitude to allocate these costs among its members. There could be a cost for joining the group, a fixed charge for each transmission service (postage stamp pricing), or non-linear charges. These charges do not relate to allocating scarce transmission resources to their highest-value uses, but rather to spreading the fixed costs of the network.

The RTG could use a variety of measures to allocate capacity in the short-run. One possibility is the use of node pricing (see C). Another would be to rely on administrative measures to deal with congested paths. However, it is unlikely that pricing would be effective as the primary instrument to allocate transmission access, coordinate its use, and plan for new resources. The bulk power grid is technically complex. It can be reasonably argued that even its current owners do not fully understand apparently simple concepts such as “capacity.” Recent studies in the power engineering literature indicate the difficulty of planning in a competitive environment (Adamson, et al., 1991; McCalley, et al., 1991). An advantage of the RTG is that it would not be limited solely to prices as a means for allocating transmission resources. The RTG could specify conditions for access, consistent with the provisions of the Energy Policy Act. The extra flexibility to use non-price conditions for access could lead to increased efficiency.

B. Centrally-Mandated Prices

A centralized determination of the cost of transmission services has the problem that it is difficult to account for individual circumstances. The FERC has recognized that transmission services provided by a utility for third parties have opportunity costs. Moving from the principle of recognizing these costs to the practice of estimating their magnitude for pricing purposes is a substantial step. At one extreme, a liberal view of lost opportunities can result in very high estimates of an appropriate transmission price. The practical result of such estimates may be very little in the way of actual transactions. This kind of approach may result in substantial limits for third party users. Without the ability to have low cost access to the network, market share for the utilities is maintained.

At the opposite extreme, a verifiable standard for identifying opportunity costs may be so strict as to deny their reality in practice. A compromise solution that would recognize opportunity costs, yet allow access, would be to price access at long-run incremental cost (LRIC). Yet LRIC for firm transmission would be too high in many circumstances. The actual cost that a transmission user imposes on a system may be much less than the cost of expanding the system to satisfy that user’s demand. In other situations, LRIC may be less than the true cost that a user imposes on the system. For example, LRIC might not account for siting constraints and delays that
add to the cost of providing transmission services. LRIC also fails to provide users with the right signals for expansion of the network.

Another approach using centrally mandated prices would be to set a price cap, perhaps at LRIC, and allow utilities to negotiate lower prices when the market allows (see Einhorn, 1990). Although this would make regulation more flexible, it would not solve the basic problem of asymmetric information about transmission costs. The greatest potential for efficient application of a price-cap approach to the pricing of transmission access would be in geographical regions where there competition is already relatively strong, as evidenced by many buyers and sellers that can access a high-voltage transmission bus. The Palo Verde switchyard in Arizona is an example, but this is more the exception than the rule in the U.S.

Prices that are mandated centrally by the FERC would amount to a de facto open access system with no limits on the parties seeking to make transactions. It is difficult to imagine exactly how such a system would work in the absence of a centralized grid authority that would apply some kind of rationing method through either price or non-price mechanisms. Nonetheless, FERC does not have the legal authority to require reorganization of wholesale market institutions by mandating power pools, for example. In some regions there will be movements toward greater cooperative activity to manage a regime of greater access, but conditions differ so much across regions that no single national policy is likely to emerge.

C. Geographical Spot Pricing (Node Pricing)

This proposal is a version of the spot pricing theory of transmission cost pricing developed by Caramanis, Bohn and Scheppe (1986), Schweppe et. al. (1988) and more fully articulated by Hogan (1992). When an electric power network is efficiently dispatched, the marginal value of transmission between any two points in the system is equal to the difference in the cost of generation at those points. The costs of generation at two points in the system may differ because there are line losses in moving power from one point to another or because transmission capacity constraints impose a congestion cost. The generation cost difference is a natural choice for the price of transmission services. At these prices, a generator should supply power to the grid if, and only if, the marginal cost of the generator plus the price of transmission to the destination is less than the marginal cost of generation at the destination.

One of the main virtues of node pricing is that it is able to deal with the troublesome problem of loop flow, also called unintended power flows. In the Hogan proposal, generation is dispatched efficiently conditional on transmission constraints. Implicit prices for transmission between node i and node j are determined ex post and are equal to the differences between the costs of generation at the two nodes. If unintended power flows cause congestion on a transmission path, the implicit transmission price is increased. This occurs because congestion limits the capacity on the transmission path, so that the difference in nodal generation costs increases. Each user of transmission has to pay for the right to send power across a desired path. Provided all users subscribe to the principle of node pricing for transmission, unintended flows are
properly priced because the node prices reflect the true cost, including unintended flows, or sending power across any path, whether or not that path is the physical circuit used for sending power from one node to another.

The main difference between the Schweppe version of node pricing and the Hogan version involves timing and information. Schweppe envisioned true spot markets. In the case of electricity this could mean a substantial degree of fluctuation and large informational burdens as the relevant spot price would vary from minute to minute. Other commodity markets settle trades over much longer time intervals. In natural gas, for example, the spot interval is one month. Furthermore, because of real-time network interdependencies, the true spot price, is in some sense the result of dispatchers decisions that are easier to report ex post than to forecast or communicate instantaneously. Therefore, Hogan (1992) proposes that the system be operated in the current fashion by a number of loosely coordinated control centers, and that node prices be computed ex post assuming the dispatch was efficient.

Efficient dispatching is an important element of node pricing. Without efficient dispatch, generation costs at each node would not correspond to the marginal value of power, and the transmission prices would be meaningless as a measure of social value. Efficient dispatch does not mean that prices must be determined in a perfectly competitive market. Monopoly owners of transmission services may dispatch their resources efficiently. If their internal marginal generation costs were public knowledge, they could be used as the basis for transmission prices. Unfortunately, if internal values are private knowledge, a monopolist could misrepresent them in a way that codifies monopolistic pricing.

Consider a transmission monopolist who serves demand at point D, owns a line from point O to point D, and owns a generating resource with a marginal cost m at point O. Suppose the line has no losses or capacity constraints. Let \( p^m \) be the monopoly price at point D \( (Pp^m = \frac{m}{1-1/\eta}) \), where \( \eta \) is the magnitude of the elasticity of demand at D. The monopolist’s internal marginal value of power is m at both ends of the transmission line. However, suppose the monopolist could misrepresent that the internal value at point D is \( p^m \). Node pricing would result in a cost of transmission equal to \( p^m - m \), which merely would serve to sustain the transmission owner’s monopoly. Of course, this inefficiency would be mitigated if the monopolist’s power to misrepresent values were limited, perhaps as a result of auditing of actual transmission operations.

A second problem with node pricing is that it does not necessarily provide efficient signals for the expansion of a transmission network. Economies of scale and cost complementarities in a transmission network suggest that local prices may be a poor signal of the most desirable way to expand the network, although this is a subject for further study.

The Hogan (1992) version of node pricing is argued to be compatible with the existing institutional structure. There is some reason to question this assertion. Implementing node pricing
requires an initial definition and allocation of capacity rights. Where transmission owners have private information about the network and this forms the basis of market power, it is doubtful whether a truly unbiased capacity definition and allocation process would or could occur. It is difficult enough without private information to define capacity in a electricity transmission network. Where private information is ubiquitous, the prospects are dim. For reasons such as this, as well as concerns over the efficiency of dispatch, Hogan has recently argued for a broader pooling structure in wholesale markets to implement node pricing (Garber, Hogan and Ruff, 1994).

D. Evaluation

The three generic approaches to transmission pricing outlined above can be expected to have different implications for industry performance. In this section we evaluate these approaches by four criteria to assess their relative merits.

D.1. Efficient Dispatch

The existing institutions in the U.S. provide for reasonable efficiency in the utilization of generating resources. This is accomplished in the “business as usual” scenario by central dispatching of units within a utility's control area. Regional transmission groups could preserve centralized dispatching, as demonstrated by the operations of existing power pools. Node pricing implicitly assumes centralized dispatching. Without efficient dispatch, node prices are unreliable indicators of transmission costs.

Clumsy regulatory intervention may have more potential to cause harm than improvement in the utilization of existing assets. The mandated access policy carries the greatest risk in this regard. If mandated access results in a pattern of generation that displaces efficient production with inefficient production, then it is not clear whether the net effect is positive.

D.2. Reliability

The existing bulk power system was built with reliability objectives in mind. As wholesale trade has increased, there is a perception among power engineers that the safety margin has declined. To a large degree, reliability in the bulk power system is a coordination problem. The interconnectedness of the network means that many real time actions are required to control or contain disturbances that may originate locally, but propagate throughout the system. While new technology is increasingly available to improve response time and automate coordinated response, this is offset by increasing the number of entities involved in managing or using the network.

The transmission policies are differentiated along this dimension in much the same way as they are with regard to efficient dispatch. Regional transmission groups are capable of maintaining a high level of reliability. Mandated access could cause some stresses by overloading particular links, or failing to require sufficient emergency co-ordination obligations. Node pricing
should result in high levels of reliability because centralized dispatching is assumed.

D.3. Choice of Service Quality

Transmission services can be differentiated according to several characteristics. These include the extent to which the service is “firm,” the probability of forced outages, the voltage level (and whether transmission is AC or DC), and the location of the service (point-to-point vs. area-wide). Users of transmission services value these characteristics differently, and proposals that allow choice in service qualities are likely to make better use of scarce transmission resources.

Regional transmission groups permit the design of pricing alternatives for transmission services with different qualities. In node pricing, each holder of a transmission capacity right is entitled to firm service over a contract path. Thus all services are “notionally firm” in the node pricing methodology. This is a disadvantage of this costing proposal, because it does not allow purchasers of transmission rights to elect different qualities of service.

Centrally-mandated prices are unlikely to provide for choices in service quality. If prices are based on the costs of transmission upgrades, the implied service quality would be firm. Under these conditions, transmission access would be required to be purchased on a firm basis when buyers might prefer a lower cost non-firm service.

D.4. Efficient Investment

This criterion speaks to the long run evolution of the electricity market. Transmission capacity is, by and large, a scarce resource. Any policy must encourage efficient expansion of the system. Existing institutions have been moderately successful at this process, but not enormously.

If buyers of transmission services have the right to force expansion when service is not available, the result may be too much expansion or expansion at the wrong place or time and in the wrong amount. If transmission owners are not obligated to expand, centrally-determined prices that only allow the owner to break even could result in too little investment. Owners of the assets would not achieve any substantial benefit from such investments and may suffer competitive losses by strengthening the position of others.

Node pricing would promises efficient signals for new investment only if the transmission cost function is well-behaved (i.e. concave). Unfortunately, there is every reason to believe that this is not the case (see, for example, Baldick and Kahn, 1993).

The regional transmission group allows a forum for the evaluation of alternative options to expand the network in a cost-efficient manner. Although private interests will attempt to promote a transmission resource plan that minimizes their individual costs, this strategizing can be checked through administrative oversight. While RTGs may encounter strategizing behavior by members that would distort investment decisions, they may improve on “business as usual” by resolving impacts on neighboring transmission systems. Both the costs of strategizing and the ability to internalize transmission impacts depend on the judicious choice of the size of the regional transmission group and on the conditions for membership.
D.5. Summary

We summarize this discussion in Table 10 where we rate the policy alternative by high performance (H), medium (M) or low (L).

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Efficient Dispatch</th>
<th>Reliability</th>
<th>Choice of Service Quality</th>
<th>Efficient Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional Transmission Groups</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>M-H</td>
</tr>
<tr>
<td>Centrally-Mandated Prices</td>
<td>M</td>
<td>M</td>
<td>L</td>
<td>L</td>
</tr>
<tr>
<td>Node Pricing*</td>
<td>H</td>
<td>H</td>
<td>L</td>
<td>L</td>
</tr>
</tbody>
</table>

* Assumes central dispatching

III. Retail Competition

The Energy Policy Act explicitly excludes transmission access for retail customers. It delegates to the states authority over the decision to allow such access. In April, 1994 the California Public Utilities Commission (CPUC) put forward a proposal to allow for competition of this kind (CPUC, 1994). Since that time a number of other states have initiated similar activities, although as of the time of this writing none of these has reached any conclusions.

The principal motive for retail competition is high electricity prices. This is cited prominently in the CPUC order, and in the literature of advocates for retail competition. For industrial customers paying 7¢/kWh or more, there are many attractive opportunities at prices ranging from 3-5¢/kWh. The short-term avoided cost in Southern California is currently about 3¢/kWh (SCE, 1994). The long term prices in Table 8 are below 5¢/kWh in the best cases; even less attractive projects would be priced at that level in the near term. Industrial electricity prices in the U.S. vary substantially by region. The states with rates at 7¢/kWh or higher in 1992 include California, New York, Massachusetts, Arizona, Northern Ohio, and Northern Illinois. In most states, industrial prices are lower than 5¢/kWh (see Table 4). In these areas retail competition has minimal potential.

If customers are allowed direct access to low cost electricity providers, there could be serious financial consequences for investor-owned utilities, and perhaps as well for customers remaining on their systems. The difference between the market price of electricity and utility rates makes a number of the utility’s assets uneconomic. The magnitude of the stranded asset problem, and the policies concerning its disposition are the major questions facing retail competition proposals.
A. Stranded Assets

The motivation for customers to seek alternative electricity suppliers is greatest where utility rates exceed opportunity costs by the largest margin. Most of the difference between rates and opportunity costs represents fixed obligations that cannot be easily reduced in the face of reduced utility demand. It is difficult to quantify the magnitude of this problem due to various uncertainties. Table 11 shows the estimates made by the Pacific Gas and Electric Company (PG&E, 1994) in response to the CPUC investigation.

Table 11. PG&E Estimates of Stranded Costs
($ Billions 1996 Present Value)

<table>
<thead>
<tr>
<th>Competitive Price (1994 $)</th>
<th>3.2¢/kWh</th>
<th>4.0¢/kWh</th>
<th>4.8¢/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E Generation</td>
<td>12.4</td>
<td>5.1</td>
<td>0.6</td>
</tr>
<tr>
<td>QF Contracts</td>
<td>4.0</td>
<td>2.9</td>
<td>2.0</td>
</tr>
<tr>
<td>Regulatory Assets</td>
<td>1.2</td>
<td>1.2</td>
<td>1.2</td>
</tr>
<tr>
<td>Total</td>
<td>17.6</td>
<td>9.2</td>
<td>3.8</td>
</tr>
<tr>
<td>PG&amp;E Generation: Proposed Settlement</td>
<td>6.3</td>
<td>1.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Revised Total</td>
<td>11.4</td>
<td>5.1</td>
<td>3.2</td>
</tr>
</tbody>
</table>

This table shows the substantial sensitivity of stranded costs to the estimated competitive market price. In all these calculations, that price is assumed to increase at an average rate of about 5% annually over a twenty year period. Additionally, the table reflects a proposed settlement that PG&E has made to reduce the cost of its most expensive asset, the Diablo Canyon nuclear plant. This proposed settlement amounts to reducing shareholder returns, thereby reducing the amount of stranded costs that customers would have to bear. The magnitude of rate impacts associated with stranded cost recovery depends upon the time period over which these costs are spread. PG&E estimates that the maximum rate impact could be as much as 23% in the case where the competitive price were the lowest of those shown in Table 11 and the recovery period were 6 years. Extending the recovery period to 12 years under the same assumptions reduces the rate impact to about 7%.

Further reductions in retail prices would need to come from price concessions by private power producers. Their prices are protected by contracts rather than the kind of regulatory bargain existing between utilities and state authorities. Therefore, these prices are likely to be less responsive.

The regulatory assets category includes a wide range of items, mostly involving costs incurred by utilities whose recovery has been delayed by agreement with state regulators. In some
jurisdictions these include recovery of nuclear investment. There is considerable variation in the incidence of these costs (Fitch Investors Service, 1993). One significant deferred cost in this category is deferred federal taxes associated with large investment programs from the past. Federal tax policy has allowed utilities to take certain benefits during the construction and early operating phases of these projects. These benefits are due for recapture, unless they could be offset further by additional investment activities. In the current slow growth environment, where investment is substantially below historic levels (see Table 6), further deferral of these obligations is unlikely.

B. Employment Impacts

To reduce costs in the face of retail competition, utilities have relatively few short term options. One which is likely to be exercised is reduced employment. U.S. utilities have been reducing their workforce in the past few years in anticipation of competitive pressures. These efforts are likely to increase substantially in the future. Data from the recent past is presented in Table 12 for major investor owned electric utilities and Table 13 for the ten largest companies (EIA, 1990;1995).

Table 12 shows that employment for the major U.S. investor owned electric utilities represented in Table 12 was 12.7% higher in 1986 than in 1993. This sample accounts for about 99% of sales from the privately owned segment. The data show some effort to adjust labor requirements through the use of part time employees, by the end of this period, adjustments in full time employment have become dominant.

<table>
<thead>
<tr>
<th>Year</th>
<th>Number of Full Time Employees</th>
<th>Number of Part Time Employees</th>
<th>Total Employees</th>
<th>Total Employment Annual Change (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1984</td>
<td>484,088</td>
<td>20,867</td>
<td>504,955</td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>492,098</td>
<td>23,138</td>
<td>515,236</td>
<td>2.04</td>
</tr>
<tr>
<td>1986</td>
<td>493,129</td>
<td>23,151</td>
<td>516,280</td>
<td>0.20%</td>
</tr>
<tr>
<td>1987</td>
<td>478,977</td>
<td>29,391</td>
<td>508,368</td>
<td>-1.53%</td>
</tr>
<tr>
<td>1988</td>
<td>474,054</td>
<td>32,722</td>
<td>506,776</td>
<td>-0.31%</td>
</tr>
<tr>
<td>1989</td>
<td>475,066</td>
<td>19,837</td>
<td>494,903</td>
<td>-2.34%</td>
</tr>
<tr>
<td>1990</td>
<td>484,651</td>
<td>16,758</td>
<td>501,409</td>
<td>1.31%</td>
</tr>
<tr>
<td>1991</td>
<td>482,127</td>
<td>15,003</td>
<td>497,130</td>
<td>-0.85%</td>
</tr>
<tr>
<td>1992</td>
<td>466,253</td>
<td>14,752</td>
<td>481,005</td>
<td>-3.24%</td>
</tr>
<tr>
<td>1993</td>
<td>446,901</td>
<td>11,172</td>
<td>458,073</td>
<td>-4.77%</td>
</tr>
</tbody>
</table>
Looking at the ten largest U.S. investor owned electric utilities, Table 13 shows a similar pattern on average, but with significant variation in individual cases. The very large employment reduction for Texas Utilities represents the end of a major construction program. This effect is absent in the other cases.

It is unclear how much further the employment reductions will go as a result of increased productivity. Compared to changes in employment levels in the UK, these are relatively modest, but the initial levels of labor productivity were much lower in the UK compared to the US (Yarrow, 1995).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pacific Gas and Electric</td>
<td>17,309</td>
<td>19,687</td>
<td>-13.74%</td>
</tr>
<tr>
<td>Southern California Edison</td>
<td>18,207</td>
<td>17,531</td>
<td>2.75%</td>
</tr>
<tr>
<td>Commonwealth Edison</td>
<td>18,757</td>
<td>17,716</td>
<td>5.55%</td>
</tr>
<tr>
<td>Florida Power and Light</td>
<td>13,058</td>
<td>15,018</td>
<td>-15.01%</td>
</tr>
<tr>
<td>Texas Utilities</td>
<td>7,560</td>
<td>12,486</td>
<td>-63.22%</td>
</tr>
<tr>
<td>Consolidated Edison</td>
<td>14,901</td>
<td>16,555</td>
<td>-11.10%</td>
</tr>
<tr>
<td>Houston Lighting and Power</td>
<td>9,581</td>
<td>10,949</td>
<td>-14.28%</td>
</tr>
<tr>
<td>Georgia Power</td>
<td>12,528</td>
<td>15,394</td>
<td>-22.88%</td>
</tr>
<tr>
<td>Virginia Electric and Power</td>
<td>11,971</td>
<td>13,585</td>
<td>-13.48%</td>
</tr>
<tr>
<td>Duke Power</td>
<td>17,677</td>
<td>19,429</td>
<td>-9.91%</td>
</tr>
</tbody>
</table>

C. Other Effects

Retail competition will have other effects as well. If it results in lower electricity prices, which is generally believed to be the case, then the macroeconomic impact should be positive. Within the electricity sector, there are likely to be shifts of activity. Research and development spending will probably decline as utilities attempt to reduce all costs which are not fixed. Utility programs directed at demand-side management, which had been significant in some regions, are also likely to decline, for very much the same reason. The burden of stranded asset costs may well be disproportionately borne by small customers.

None of these potential effects within the sector are certain to occur, all raise
controversial issues, and are significant topics for political discussion. There is widespread interest in negotiating a compromise among the various interests, but no clear lines along which such compromises may be drawn.

IV. Conclusions

Deregulation of the U.S. electricity sector is proceeding steadily, but unevenly. Competition at the wholesale level is increasing. Both the short term transactions market and the long term market for new capacity show vigorous new forms of entry and substantial downward pressure on prices. The central question of pricing transmission access remains unresolved.

Competition at the retail level is more controversial. Pressures for such competition are greatest where utility rates are high. The resulting stranded assets may be written down in the case of utility ownership. Where these assets are private power contracts, it is more difficult to anticipate whether and how the pressures may be resolved.

It is almost certain that competition at both the wholesale and retail levels will result in structural changes. The large number of investor-owned utilities is likely to decline further through consolidation. The viability of vertical integration is more uncertain. Given the predominance of private ownership, restructuring assets is costly and time consuming, because of the number of private and public claims that need to be satisfied.
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2. United Kingdom

ELECTRICITY PRIVATIZATION
IN THE UNITED KINGDOM AND ITS RESULTS

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Institute of Economic Affairs
1. A brief history

1.1 The nationalised period

The electricity supply industry in Britain was nationalised by the Electricity Act of 1947, as part of the sweeping programme of nationalising the ‘commanding heights’ of the economy carried out by the 1945-51 Labour Government under Prime Minister Clement Attlee.

Prior to nationalisation the industry had been regulated by the state almost from its beginnings in the late nineteenth century and the degree of regulation had grown in the interwar period. In 1919, Electricity Commissioners, responsible to the Minister of Transport, were appointed and in 1926 a Central Electricity Board was established to construct and own an electricity grid; the Board could give directions to power station owners and the Commissioners could determine the price of electricity from power stations if the Board and the owners could not agree.

Nationalisation was seen at the time as the logical next step in this trend towards greater state involvement in the industry. The initial structure of the industry under nationalisation was a development of earlier regulatory schemes, designed to cope with what was perceived to be a rather complex industry. Most nationalised industries were run by a single corporation with Board members appointed by the responsible Minister. In electricity, however, there were a number of corporations.

Under the 1947 Act, a British Electricity Authority was created which took over generation and transmission and was the dominant force in the industry. It was responsible for raising finance after scrutinising the expenditure plans of the industry as a whole. Distribution was in the hands of twelve Electricity Boards in England and Wales and two in the south of Scotland. The vertically integrated Hydro Electric Board, established in 1943, continued to cater for the north of Scotland. The industry was given a monopoly of the public supply of electricity.

Electricity supply was reorganised several times in its nationalised period in the search for an effective structure. In 1955 the two Boards in the south of Scotland were amalgamated. But the most important reorganisation came in 1957 when the Electricity Act of that year established a structure for England and Wales which persisted until the industry was privatised in 1990. The 1957 Act created the Central Electricity Generating Board (CEGB), responsible for both generation and bulk transmission in England and Wales: the CEGB controlled the bulk of the industry’s investment and was de facto its most powerful organisation. Twelve Area Boards took electricity from the CEGB’s bulk supply points, then distributed and supplied it within their designated areas. An Electricity Council had somewhat vague policy-making and co-ordinating functions: it contained three representatives of the CEGB, the twelve Area Board Chairmen and six independent members.

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1 The history of British electricity supply from the late nineteenth century to 1968 is summarised in R. Kelf-Cohen, Twenty Years of Nationalisation: The British Experience, Macmillan, 1969, especially Chapter 4.
appointed by the Minister.

In Scotland, two vertically integrated boards - the South of Scotland Electricity Board (SSEB) and the (smaller) North of Scotland Hydro Electric Board (NSHEB) - generated, transported and supplied electricity to consumers in their respective areas.

1.2 Problems under nationalisation

In common with other British nationalised industries, during its period of government ownership electricity was beset with the problems which arise from the absence of competition in the product market and the capital market and from the politicisation of decision-making:

- because entry to the industry was prohibited, consumers lacked the power of exit. Consequently the various corporations in the industry had little incentive to take consumers' interests into account;
- because the industry was outside the market for corporate control, there was no takeover threat to stimulate efficiency improvements. There are bound to be serious agency problems when the ultimate 'owners' of a business are the voting public who have no transferable property rights;
- the industry's monopoly in the product market translated into considerable bargaining power for its unions which appeared to secure very favourable arrangements for their members;
- the politicisation of decision-making meant that managerial objectives were confused by uncertainty over whether 'commercial' or 'public service' objectives should be given priority. Both investment programmes and prices were influenced (and at times controlled) by government. For example, in the 1970s, a Labour Government persuaded the industry to hold down its prices in an effort to keep down the general rate of consumer price inflation; in the 1980s, a Conservative Government made the industry increase prices to reduce public borrowing.

A succession of White Papers on the nationalised industries (in 1961, 1967 and 1978), which dealt with economic and financial targets and relations with government, did little to help. Well-meaning pronouncements, such as those in the 1967 White Paper - the injunction to price on the basis of long run marginal cost and to adopt test rates of discount similar to those used for low-risk private sector projects - were over-ridden by the political calculus, by a lack of will in the nationalised corporations and by the practical difficulties of applying such concepts.  

Moreover, the electricity supply industry became the principal support system for the

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nationalised British coal industry. From 1957 onwards, as British coalmining went into decline - because oil and gas prices declined relative to the price of indigenous coal and consumers substituted those fuels for coal - governments began to protect the industry from competition. The dominant method of protection came to be government pressure on the nationalised electricity industry to burn more coal than it would freely have chosen. From 1979 onwards, previous arrangements were formalised into a series of government-brokered 'Joint Understandings' under which the nationalised electricity supply industry agreed to take nearly all its coal (at that time nearly 90 million tonnes a year) from the nationalised coal industry.

The electricity supply industry was also used to support two programmes of British-designed nuclear power stations, the first (Magnox reactors) beginning in 1955 and the second (Advanced Gas Cooled Reactors) beginning in 1965. It provided more general support for British industry, for example through its 'Buy British' policy for generating plant. The electricity industry under nationalisation therefore became an instrument of government energy policy and government industrial policy.

1.3 The transition to privatisation

The difficulties which arose under nationalisation are significant partly because they influenced the privatisation scheme but also because they established a starting point from which the changes brought about by privatisation occurred. Removing the constraints of government ownership from an industry which had been more affected by them than most - and which had been an instrument of government policies for over thirty years - was bound to have drastic effects on employees, on consumers and on associated industries.

By the late 1970s, there was a widespread perception that nationalisation British-style had not worked well. Proposed remedies varied, from tighter state control to denationalisation. But, given the change in intellectual climate in the late 1970s and 1980s towards a belief in greater reliance on markets, and given the election in 1979 of a Conservative government under Mrs Thatcher determined to reduce the role of the state, the denationalisation approach prevailed. From 1981

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5 Heald, op. cit.
onwards, the Thatcher governments began to privatisate state corporations nationalised by Attlee or subsequently.7

These moves were at first tentative, denationalising industries already in competitive markets (such as Cable and Wireless, Amersham International, Britoil, Enterprise Oil and Jaguar).8 Then in 1984 came Britain's first privatisation of a major utility when 50 per cent of the shares in British Telecom were sold to the public. The political success of this privatisation - in terms of the widening of share ownership it achieved, the revenue it raised, the favourable media publicity it attracted, and the subsequent boost to the government’s popularity - made it a landmark in the privatisation programme. From then on, the government was keen to proceed speedily with privatisation of the other utilities.

In 1986, British Gas was privatised in another politically successful move, though gas privatisation - which left the privatised British Gas Corporation as a very powerful incumbent - was heavily criticised by some economists.9 Soon afterwards, electricity privatisation moved on to the political agenda: the Conservative Party’s election manifesto of May 1987 promised to ‘...bring forward proposals for privatising the electricity industry subject to proper regulation’.

1.4 The electricity privatisation scheme

The privatisation scheme was explained in two White Papers of February and March 1988 - one for England and Wales and the other for Scotland.10 Under privatisation, as under nationalisation, there are different regimes for the two areas.

After the criticisms that gas privatisation had failed to liberalise the gas market, the government decided that, to reduce incumbent power and to attract new entry to electricity generation and supply, the generation and transmission functions previously in the CEGB should be separated. The National Grid Company (NGC) was established as a transmission company which allows access on equal terms to all parties, which despatches plant under the pooling regime (3.4 below) and operates two pumped storage power stations. All shares in NGC were initially held by the Regional Electricity Companies (RECs) but it is due to be floated separately towards the end of 1995.

7 Privatisation, both in principle and in practice, is described in John Vickers and George Yarrow, Privatisation: An Economic Analysis, MIT Press, 1988.
It was decided also that, to promote competition in generation, the CEGB's generation activities should be divided between two companies - National Power and PowerGen. During the debate about the appropriate form of electricity privatisation, proposals had been made for a more radical scheme in which the CEGB would be divided into six or more generators.11 But the CEGB strenuously opposed both the separation of transmission from generation and any division of generation. It was not so successful as British Gas had been in its attempt to remain whole but it did succeed in persuading the government that a division into only two generators should be made. Only 60 per cent of the shares in the two generators were sold at the time of privatisation: the government retained the other 40 per cent until they were sold in March 1995.

Distribution and supply of electricity to consumers in England and Wales were placed in the hands of twelve RECs, each based on an existing Area Board. RECs must make their distribution networks available to third parties on the same terms they apply to their own supply businesses. RECs are also allowed to generate electricity, but (to prevent the emergence of vertical integration) only up to a limit of 15 per cent of their supplies.12

To permit competition in supply to develop, the privatisation scheme provided for each REC’s monopoly power to be gradually reduced. From ‘vesting day’ (1 April 1990) large consumers with a maximum demand in excess of 1 MW (about 5000 in total) were allowed to ‘shop around’ for electricity: they could take supplies from their local REC, or via ‘second tier’ supply from another REC, from one of the generators (though there were some limits on direct sales by National Power and PowerGen for a short period) or from one of the Scottish companies. The threshold for the monopoly market was reduced to 100 kW in April 1994 bringing about 50,000 more consumers into the competitive market. From April 1998 onwards there will no longer be a captive ‘franchise’ market of smaller consumers. All consumers (including residential) will be able to choose supplier. A novel feature of electricity supply in England and Wales is therefore that, on present plans, by 1998 all electricity consumers will have the power of exit.


12 The electricity regulator has said that in some circumstances he will agree to increase this limit. See S.C. Littlechild, ‘Competition in Electricity: Retrospect and Prospect’, in Utility Regulation: Challenge and Response, Institute of Economic Affairs, IEA Readings No.42, 1995.
1.5 The problem of nuclear power

Nuclear power caused the government considerable difficulties as it proceeded to a flotation of shares in the new electricity companies.\textsuperscript{13} The 1988 White Papers envisaged privatisation of nuclear power. Existing nuclear stations in England and Wales were to form part of National Power, the larger of the two generating companies: indeed, one of the principal reasons why the government opted for only two generators was that it wanted to establish a very large company within which the nuclear stations would not appear too prominent. But that part of the scheme was thwarted in 1989. The City was alarmed not only at the estimates of nuclear generating costs but also at the uncertainty associated with those costs. Estimates of back-end costs, in particular, increased sharply in 1988 and 1989 when the privatisation scheme was under discussion and more information was revealed about nuclear costs than had previously been available.\textsuperscript{14}

As the success of privatisation appeared threatened, first Magnox stations and then the AGRs were withdrawn from the scheme: by November 1989 the government had conceded that it would have to retain nuclear stations in state ownership. One nationalised company (Nuclear Electric) took over nuclear stations in England and Wales - Magnox, AGR and one PWR (Sizewell B) under construction. Another company (Scottish Nuclear) took over the two Scottish AGRs and a Magnox station which was being decommissioned. There had been a plan to build three more PWRs to complete a ‘family’ of four but this was dropped, at least temporarily, in November 1989 when existing nuclear stations were withdrawn from privatisation.

At the same time, a system was established under which the RECs are contractually obliged to take the bulk of the output of the nuclear stations in England and Wales as baseload under a Non-Fossil Fuel Obligation (NFFO). Essentially, the system is that the RECs are compensated from the proceeds of a fossil fuel levy (amounting to around 10 per cent on most electricity bills excluding auto-generators and CHP plant) for the excess cost of using nuclear electricity as compared with fossil-generated electricity.\textsuperscript{15} This form of protection was originally due to cease in 1998 but, under new proposals to privatise nuclear power (see 5.2 below), the government said in May 1995 that protection would end in 1996.


\textsuperscript{14} ibid.

\textsuperscript{15} The levy supports renewables as well as nuclear power but about 97 per cent of the proceeds go to nuclear.
1.6 Privatisation in Scotland

The privatisation scheme for Scotland involved less disturbance of pre-existing arrangements than in England and Wales. Two vertically-integrated private companies were established, one (Scottish Power) based on the SSEB and the other (Hydro Electric) based on the NSHEB. The nuclear stations built by the SSEB were, as explained above, transferred to Scottish Nuclear: under a Nuclear Energy Agreement which lasts until 2005, all their output must be taken by Scottish Power and Hydro Electric. Until 1994, Scottish Nuclear received a premium price; but from 1995 onwards the price is gradually to be brought into equality with the baseload price in the England and Wales pool. According to the 1995 nuclear privatisation proposals (1.5 above), the premium price scheme for nuclear electricity in Scotland will end in 1996 (when the fossil fuel levy ends in England and Wales).

1.7 Regulation

Regulation of the industry is, as in other privatised industries, in the hands of a specialist regulatory office - in this case, the Office of Electricity Regulation. OFFER licenses companies in the industry; it can modify licences with the consent of the holder or refer matters in dispute to the Monopolies and Mergers Commission (MMC). In some cases it has joint powers with the Secretary of State for Trade and Industry. Price regulation formulae of the RPI-X variety, similar to those used in other British privatised utilities, are applied separately to transmission, distribution and supply charges and reviewed at intervals of five years or less. The price cap formula is not applied to generation since the government assumed there would be sufficient competition to protect consumers. That assumption has turned out to be incorrect as explained in 3 below.

2. Privatisation, nationalisation and government failure

2.1 Differences from nationalisation

The privatised electricity market is very different from what went before. In addition to the structural changes at the time of privatisation, the three most significant differences are

- entry is now permitted to both the generation and supply businesses whereas previously it was prohibited by the state;
- the electricity companies now have private shareholders, instead of being owned by government;

regulation is by an independent body instead of being conducted behind closed doors, with unclear rules, by politicians, civil servants and industry managers.

In principle, these changes should have been beneficial. Actual and threatened entry should have brought increased rivalry in generation and supply, leading to increased efficiency pressures and lower costs which, in a competitive market, would have been passed on to consumers in the form of reduced prices and better standards of service. The industry's entry into the market for corporate control should also have enhanced efficiency pressures and reduced the incentives which existed under nationalisation to concentrate resources on political lobbying: the industry's decisions about which fuels to use, which investments to make, whether to purchase British or overseas equipment and services and what prices to charge should no longer have been subject to government influence. Regulation should have been confined to natural monopoly networks and based on clearly defined rules.

In practice, however, many of these potential gains have yet to be achieved.

2.2 Government failure and electricity privatisation

Of course, it was to be expected that competition would take time to find roots in the British electricity market. After all, the industry had been nationalised for over forty years and, before that, was supervised by government. Competitive habits take time to form and market participants have to learn to substitute contractual relationships for the old co-operative relationships within firms.

However, the reason why many of the potential beneficial results of privatisation and market liberalisation are so far unrealised is not just that insufficient time has elapsed. The underlying problem is government failure to establish at the time of privatisation conditions in which a competitive process could flourish in product markets. Government also seemed unwilling to expose companies in the industry to the threat of takeover, using the device of 'golden shares' as in other privatisations.

Particular difficulties have been caused by the decision to establish a duopoly in generation. Since generation has no natural monopoly elements and a rivalrous market clearly could have been created, that decision was seen by some economists as a serious error. It has had consequences the government evidently did not intend. Despite substantial entry by new generators, the market power of National Power and PowerGen has not as yet been significantly disturbed:

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18 Several bids for RECs have been made since their golden shares expired in March 1995 (5.3 below).
19 Robinson, 'Liberalising the Energy Industries', op. cit.
pooling system and the contractual relationships which have developed (partly because of the duopoly) have allowed the two major generators to retain their influence over wholesale prices. Competition in supply to larger consumers has developed, but genuine competition in generation is still lacking: it is symptomatic of the absence of rivalry that the regulator has had to supervise generation much more closely than the government expected (5.2 below).

In the rest of this paper, the characteristics of the privatised market are analysed, with the emphasis on those which have inhibited competition, and regulation is discussed. Since one of the most fundamental issues is the duopoly and its consequences, that is the starting point.

3. Competition in generation

3.1 The generation duopoly

Whatever the privatisation scheme, incumbent generators would have had some advantages over entrants. In addition to the usual ‘advantage’ of having plant with sunk costs (but see 3.3 below), they possessed sites linked into the transmission and distribution systems; more generally, as descendants of the nationalised industry they could take advantage of that industry’s near-monopoly of information about all matters relating to electricity generation in Britain.20

But the duopoly structure of generation imposed by the privatisation scheme gave considerable additional power to the two major generators. Electricity is a product for which the short period price elasticity of demand is low yet, since the product is homogeneous, the price elasticity of demand for the product of any generator is very high. Thus conditions exist in which a small number of producers can take advantage of the inelasticity of the market demand curve by suppressing competition among themselves.

Establishing a duopoly, as the British government did, made it relatively easy for incumbent generators (and later Nuclear Electric - see 3.7 below) to avoid forms of competition which would have disturbed their market power. That is not to suggest they had explicit agreements. Tacit collusion - which is relatively straightforward in a duopoly, particularly when the two companies have been formed from one parent and probably have good knowledge of each other’s costs - is a

much more likely outcome of this kind of market.

3.2 Entry and constraints on competition

Nevertheless, given that entry to the market was freed, the initial structure might appear of only transient importance: the power of any duopoly would seem unlikely to persist because of a Schumpeterian gale of creative destruction in the course of which entrants would compete away the profits of incumbents to the benefit of consumers. Possibly electricity privatisation is at too early a stage for one to judge when such a gale will gather force. But there are a number of severe constraints on competition, which may persist for many years, and which have so far shielded the major generators from the rivalry of entrants. These constraints are analysed below: all are either unintended consequences of the duopoly or of past government actions.

3.3 Fuel use, entry and the ‘dash for gas’

One of the most significant changes consequent on privatisation was relaxation of political constraints on generator fuel choice. These constraints had been in operation for over thirty years and were one of the prime determinants of the initial fuel mix of the privatised industry.

Under nationalisation governments ensured that the industry burned British coal and constructed British-designed nuclear power stations (1 above). The CEGB’s fuel mix at the time of privatisation therefore consisted largely of coal, with a substantial additional element of nuclear power. To maintain support for British coal and nuclear power, successive governments operated a de facto ban on the use of natural gas in power stations, starting in the mid-1960s when gas was found in the southern North Sea: it was subsequently reinforced by a similar move by the European Community. Because of these prohibitions, there was considerable pent-up demand for gas as a generation fuel by the time of electricity privatisation in Britain.

On privatisation, with government constraints on fuel use relaxed, the two major generators in England and Wales immediately began to diversify away from a fuel mix which they perceived to be costly relative to the alternatives and excessively polluting. About three-quarters of their plant capacity was coal-fired or dual-fired (coal and oil), with the rest mainly oil, as Table 1 shows. Their fuel mix was an incumbent disadvantage which offset some of their advantages. They no longer had any nuclear stations, though the output of those stations had to be taken by the RECs and had a share of about 17 per cent of pooled output in 1990 (Table 2).

For a time the generators’ diversification moves were severely hampered by government

insistence that they sign contracts with British Coal for the first three years of privatisation (up to March 1993) to take substantial amounts of coal - 70 million tonnes a year reducing to 65 million tonnes. The extra costs incurred by the generators in signing these contracts appear to have been passed on via the RECs to consumers in the franchise market. But the generators were still able to lay plans to build new CCGT stations, to be commissioned post-1993, which appeared the cheapest form of baseload generation, which had short construction times (two to three years) compared with coal or nuclear stations and which also offered advantages in meeting EC sulphur emission targets. From 1993 onwards, the coal contracts were reduced - to 40 million tonnes in 1993/94 and 30 million tonnes a year for the next four years - and constraints on fuel choice were much diminished.

At the same time, entrants to the generation industry appeared, all choosing to build CCGT stations. The resulting ‘dash for gas’ was on a considerable scale. By early 1995, National Power and PowerGen had 6300 MW of CCGT stations either commissioned or under construction. As well as their wish to diversify away from coal, the two generators may have been making a pre-emptive strike at potential entrants by building, and announcing plans to build, CCGT stations. Further comments on the generators’ possible motivations are in 6.1 below. Whatever the reasons, by early 1995 entrants had commissioned or under construction a little more CCGT plant than National Power and PowerGen - about 6900 MW (over 10 per cent of pooled generation capacity in England and Wales). One consequence of the ‘dash for gas’ was to accelerate the decline of the British coal industry (see 6 below).

As a result of new entry (and also an increase in Nuclear Electric’s market share), there has been a substantial decline in the shares of National Power and PowerGen of pooled output. In 1990-91, as Table 2 shows, National Power’s market share was over 45 per cent and PowerGen’s share was 28 per cent: but in the year ending September 1994 those shares were down to 34 per cent and 25 per cent respectively. Nuclear Electric, which has been successful in increasing the output of its AGRs, increased its share from 17 to 23 per cent over the same period. New entrants accounted for about 7½ per cent of pooled output in the twelve months ending September 1994 and that share will increase to about 10 per cent as capacity under construction is commissioned.

3.4 The pool and its effects

Given this volume of entry in a relatively short period, it might seem that the market power of the major generators would inevitably be curbed. But, despite the reduction in their market share, the impact on their ability to set prices has been minimal: as explained below, the electricity pooling system in England and Wales, established by the privatisation scheme, has concentrated their influence on a crucial segment of the market to such an extent that they continue to be price-makers.

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23 Littlechild, op. cit.
The electricity pool is a central despatch and settlement system in which the National Grid Company (NGC), the privatised transmission company, has a central role in matching supply and demand. Under nationalisation, the CEGB operated a ‘merit order’ in which it despatched plant in ascending order of operating cost. Under the new regime, pool membership is a requirement of generation and supply licences so all substantial generators are compelled to use the pool. Electricity supplied to Britain via a 2 GW link with France is also sold into the pool. Generators submit price bids for each generating unit for each half hour of the following day. NGC then orders the bids and despatches plant in merit order to meet its estimate of demand. A difference from the nationalised regime is that the merit order is based on price bids rather than estimated operating costs.

Each generator receives a price which is the sum of two elements. The first is the System Marginal Price (SMP) which is the price bid by the marginal generating unit in the relevant half hour. The second is a capacity payment for all capacity declared available (whether or not it runs) which is the product of the ‘loss of load probability’ (LOLP) and the ‘value of lost load’ (VOLL).

VOLL is intended to place a value on the cost to consumers of a power shortage. It was set initially at £2 per kWh, indexed to the rate of inflation: in an apparent hangover from the days of nationalisation a central judgement is made about how consumers value lost load rather than those consumers being allowed to decide for themselves. The effect of the capacity payment term in the pool price formula is that as demand moves closer to declared capacity, so the LOLP increases and payments to generators increase. Thus incipient shortages translate into a price signal to make more existing capacity available and to invest to increase capacity, albeit the signal is based on an apparently arbitrary estimate of VOLL.

Purchases of electricity are not at PIP but at the pool output price (POP) which is higher at certain times of day to the extent that it includes ‘uplift’ payments - for example, to cover the cost of transmission constraints, maintenance of reserves and other system costs.

This pooling system has combined with other characteristics of the privatised electricity market to accentuate the market power of National Power and PowerGen. If entry to the generation industry consisted of a diversified mix of plants in terms of load factor - some operating on baseload, some mid-merit plant and some peaking plant - SMP would be set in rivalrous conditions. However, in practice National Power and PowerGen have set SMP almost all the time because of the lack of competition outside the baseload power market.

3.5 Entrant/REC relationships

The reasons why there is minimal competition outside the baseload market are traceable back to establishment of the duopoly, to avoiding action taken by the RECs and to the characteristics of contracting under the privatised regime.

24 Vickers and Yarrow, The British Electricity Experiment, op. cit.
As already explained, all entry to generation has so far been by companies with CCGT plants. Most entrants are associated with one or more RECs which either have an equity stake in the company or a long-term (usually 15-year) contract with it for the supply of power. RECs have regional monopoly power – they are incumbents with a monopoly over smaller consumers until 1998 and, as successors to the old Area Boards, a near-information monopoly about local conditions – and so possess considerable freedom of manoeuvre in contracting.

RECs have used this freedom to form close equity or contractual relationships with entrants to generation \(^{25}\) because they have wished to diversify sources of electricity supplied to them, avoiding dependence on a duopoly in generation. RECs are limited in the amount they can generate themselves to 15 per cent of supplies (1 above) but they are not restricted in their ability to contract with entrants to generation provided they meet an obligation to purchase economically. Thus the presence of a generation duopoly has more significance than the direct constraints it places on competition in generation. It has led also to the REC/entrant relationships just described: had the CEGB been split into more generators, the RECs would have had less incentive to diversify in this way.\(^ {26}\)

These contractual relationships have in turn influenced the development of competition as between baseload and non-baseload. The long-term contracts which the entrants have with RECs are mirrored by the long-term contracts entrants have signed to take gas from fields in the North Sea. These contracts are ‘take-or-pay’, as most North Sea gas contracts have been since 1968 when British offshore gas first began to flow: take-or-pay contracts with high minimum bills are a characteristic development in a monopolised and monopsonised gas market such as existed at that time as a matter of government policy.

Because they have take-or-pay, minimum bill contracts, entrant generators find a large element of their gas purchase costs is fixed. Thus the marginal cost of gas to them is zero and they have a powerful incentive to maximise the volume of their gas sales by bidding into the pool at whatever price will secure baseload operation. Thus despite the large volume of entry, all the entrants’ plant runs on baseload. None competes with mid-merit and peaking plant. Nuclear stations also run on baseload. All non-baseload plant (left over from the days of nationalisation) apart from pumped storage is still owned by National Power and PowerGen. Consequently, SMP is set about 85 per cent of the time by those two companies (in most of the other 15 per cent, NGC’s pumped storage stations set SMP - see 5.1 below). Two recently announced CCGT projects (with a capacity of about 1000 MW in total) seem to be on a different basis: it appears that in neither case is there a long-term power purchase contract with a REC but it is not clear whether they mark the beginning of a new


\(^{26}\) Robinson, Energy Policy, op. cit.
3.6 Unintended consequences and the development of competition

Summarising, the British government’s privatisation scheme for electricity generation resulted in a stream of unintended consequences.

First, in order to placate the management of the CEGB and to make nuclear privatisation easier (though in the event that privatisation did not take place in 1990), the government established a duopoly in generation. Second, because of past government action there was a huge pent-up demand for gas which meant that any new entrants would build gas-fired plant, buying their gas in a market where (again because of past government actions) take-or-pay contracts were the norm. Third, the RECs - concerned at the market power of the duopolists - decided to circumvent it and so teamed up with new entrants on long-term contract. Fourth, all the new plant is on baseload and so competes with existing generators only in that part of the market. Thus the incumbents retain market power in that crucial segment of the market where, because of the characteristics of the pooling system, prices are set. The market features mentioned above have controlled competition, channelling it into areas where it would least affect incumbents and have least impact on wholesale prices. Some of the effects on prices to consumers are discussed in 4 below.

The (unintended) consequences for competition in generation are serious. A recent calculation by the Office of Electricity Regulation\(^{28}\) shows that in 1993-94, National Power and PowerGen had 95 per cent of non-baseload output (compared with 55 per cent of baseload output). So entry to the industry has depressed the major generators’ share only of baseload output. Of course, as National Power and PowerGen stations are displaced from baseload they compete with mid-merit and peak plant: but virtually all the plant concerned is owned by the two big generators so, as OFFER concluded, ‘The two companies are thus competing only with each other for a critical part of the load curve’.

Another feature of generation which the Director General of Electricity Supply (DGES) has pointed out,\(^{29}\) is that the major generators’ shares of capacity have declined less than their shares of output. On vesting day, their combined share of output was the same as their share of capacity - 78 per cent. But, though their share of output has declined to 59 per cent their share of capacity has fallen much less - to 69 per cent. The presence of this substantial amount of spare capacity waiting in the wings - which can be brought into the market if the two generators choose and will then affect capacity payments - is likely to be a deterrent to entry.

\(^{27}\) Littlechild, op. cit.
\(^{28}\) Littlechild, op. cit.
\(^{29}\) ibid.
3.7 The contracts market

Although most generated electricity is pooled, there are considerable risks to market participants in relying on a spot market such as the pool, particularly in view of the distortions discussed above. Variations may occur not only for the reasons one would expect in any electricity market - according to time of day and season of year and because of unexpected weather or other unpredicted events. In the pool, there is the possibility of strategic gaming by the duopolists.\textsuperscript{30}

Experience has now revealed how large variations in the pool can be and how they tend to be magnified by the LOLP/VOLL mechanism (see 3.4 above). In January 1995, for instance, there were some particularly large fluctuations in pool prices, caused apparently by the temporary closure of two nuclear power stations which affected prices primarily by increasing LOLP. On one day in late January, PIP reached a maximum of over 63 pence per kWh between 17.30 and 18.00 hours with a corresponding POP of over 72 pence, as compared with minima in the early hours of the same day of only 0.9 pence. On another day in April 1995, there was a short period during which the input price rose above 83 pence per kWh (though there were evidently software problems at the time).\textsuperscript{31}

To protect against pool price fluctuations, a contracts market has developed in England and Wales through which most electricity is traded. ‘Contracts for differences’ (CFDs) - in which the differences are from a strike price - between generators and electricity suppliers settle in advance the price at which most electricity is bought and sold, thereby protecting against the uncertainty of pool prices.

The presence of CFDs tends to make generators less concerned about pool prices than they would otherwise be, but they are not always fully contracted and so may be affected at the margin by pool price fluctuations. RECs and large consumers also protect themselves by CFDs but again some may be affected at the margin and some large consumers (such as ICI and other chemical companies)\textsuperscript{32} purchase at pool prices. It is also, of course, true that over a period of years there must be a relationship between pool and contract prices since consumers have the option of buying at one or the other price.

Lack of competition in the contracts market (as well as in the pool) has concerned the industry regulator. There are three big players in the contracts market - National Power, PowerGen and Nuclear Electric - all of which have an incentive to keep up prices rather than compete


\textsuperscript{31} ‘Power price reaches record levels’, The Financial Times, 12 April 1995.

vigorously. Tacit collusion in a triopoly is therefore a possibility. OFFER’s evidence to the
government’s 1994-95 nuclear review is forthright about the ineffectiveness of Nuclear Electric as a
competitor to the two big privatised generators.\(^{33}\) It points out that Nuclear Electric has contracted
a significantly lower proportion of its output than the other two generators: according to OFFER, its
‘limited contribution’ to the contracts market may have been a ‘significant factor in restricting the
availability of contracts and maintaining higher prices than would otherwise obtain’.

3.8 Efficiency gains: reducing inputs and input prices

Despite the weakness of competition in generation, one effect of privatisation has been to
stimulate remarkable reductions in costs by National Power and PowerGen.\(^{34}\) Now they are in the
market for corporate control and they find political constraints on fuel choice much reduced, the two
generators have moved to cheaper and much less labour-intensive gas-fired generation. They have
also negotiated lower prices for the coal they are still burning now they are no longer forced by
political pressures to contract for such large quantities of British-mined coal.

The most striking expression of these cost reductions is in the manning economies which
have been achieved (revealing the degree of disguised unemployment which existed during the
years of nationalisation). National Power and PowerGen reduced their workforces by over
two-thirds in the first five years of privatisation (Table 3) and are continuing with reductions
though at a slower rate. Labour force reductions in the RECs were smaller - about 13 per cent on

The prices of generation fuels have also fallen compared with what they were when they
were heavily influenced by government actions to protect British coal and nuclear power. In 1994,
the major generators paid about 23 per cent less for their coal than they did, on average, in 1988.
The price of natural gas, which has only been used on any scale in power generation since early
1993, fell 13 per cent between then and fourth-quarter 1994.

Predictably, given that serious rivalry has yet to develop in generation, a large part of these
efficiency gains seems not to have been passed on to consumers. Consumer price trends are
analysed in 4 below.

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\(^{33}\) Office of Electricity Regulation, Submission to the Nuclear Review, October 1994.

\(^{34}\) Colin Robinson, Liberalisation of the Energy Market: A Favourable Supply Side Shock for the UK
4. Consumer price trends

Until recently the results of electricity privatisation in terms of prices were disappointing, even in the sectors of the market where consumers had choice and despite the considerable cost reductions mentioned in 3.8 above. A study carried out in 1992 suggested that prices in the early privatisation period were considerably higher than might have been expected on the basis of pre-privatisation trends. Since 1993, however, prices to most consumers have tended to stabilise or fall.

To place movements in electricity prices in the context of changes in fuel prices in general, Figure 1 illustrates quarterly trends in coal, fuel oil, gas and electricity prices to industry (all expressed in thermal equivalent terms) since first quarter 1988. That period is taken as the starting point because the White Papers on electricity privatisation were published in February and March 1988: from then onwards, electricity prices began to adjust to the prospect of privatisation.

In essence, the Figure shows that average coal prices to industry have fallen somewhat, that gas prices have fluctuated around an approximately constant trend and that fuel oil prices have tended to increase (abstracting from the sharp rise at the time of the Iraqi invasion of Kuwait in 1990). Despite the declining costs of labour and fuel inputs, electricity prices have risen significantly. Comparing fourth quarter 1988 with fourth quarter 1994 (to minimise seasonal effects), the increase is about 19 per cent, equivalent to an annual average compound rate of nearly 3 per cent.

Some specific factors in the electricity market help explain these increases relative to gas and coal prices. One is the considerable electricity price increases just before privatisation which were generally interpreted as government-inspired efforts to ‘fatten up’ the industry. Another is the loss of a scheme under which about 4 million tonnes of coal a year was provided to the CEGB by British Coal at around world prices: the benefits of the electricity deemed to be produced from this coal were passed on to about 400 large consumers under the so-called QUICS (Qualifying Industrial Consumers’ Scheme). Another factor is the gradual introduction of competition because of which only consumers of 1MW or over had a choice of supplier between vesting day in April 1990 and March 1994. As Figure 1 shows, industrial electricity prices in 1994 (when the competitive market had expanded) were rather lower than in 1993.

The companies which have suffered most from electricity price increases are very large consumers which lost their subsidies; according to DTI statistics, (on which Figure 2 is based) ‘extra large’ consumers were paying 32 per cent more for their electricity in fourth quarter 1994 than in fourth quarter 1989 (1989 is as far back as the statistics go). Companies too small (less than 1MW demand) to have a choice of supplier before April 1994 also fared badly before they entered the

35 George Yarrow, British Electricity Prices Since Privatisation, 1992.
36 Department of Trade and Industry, Energy Trends, HMSO (monthly).
competitive market: in first quarter 1994 they were, on average, paying 25 per cent more for their
electricity than in first quarter 1989. By the fourth quarter of 1994, however, the effects of
competition were apparent: the average price they were paying was only about 4 per cent higher
than in fourth quarter 1989.

Moderately large and medium size consumers - which have been in the competitive market
from the beginning and had no subsidies to lose - have, as one would expect, fared better. They had
fairly small price increases of about 7½ per cent each from third quarter 1989 to third quarter 1994.
Prices paid by both groups have been tending to decline recently: in fourth quarter 1994 the prices
they paid were about the same as in fourth quarter 1989.

Outside the competitive market, residential consumers - who are the captives of their local
RECs until 1998 - have faced big increases in electricity prices since privatisation. Increases in
domestic electricity prices have outstripped increases in other domestic fuel prices since the late
1980s. Domestic electricity prices in fourth quarter 1994 were about 48 per cent higher than in the
first quarter of 1988 whereas the price of gas (electricity's main competitor in homes) was only 29
per cent higher. Most of the increase in domestic electricity prices took place between 1988 and 1992
since when, eliminating the effect of the imposition of VAT in 1994, prices have fallen slightly.

In general, benefits to consumers (in terms of prices) seem small when set against the
efficiency gains since privatisation. The trend does, however, appear to be changing and it may well
be that prices to most consumers will fall over the next few years because of increasing supply
competition and tighter regulation of distribution charges.37

5. Regulation

5.1 The difficulties of regulation in electricity

From the earlier part of this paper it will be obvious how large a burden falls on the Office
of Electricity Regulation. In a paper written when the 1988 White Papers on electricity
privatisation were published I suggested that the scheme would make the regulator's task
'...extremely difficult if not downright impossible' and that 'The root of the regulatory problem...will
be the failure to establish an initial structure of generation which is clearly likely to stimulate
competition'. With a competitive generation sector, regulation would have been able to
'...concentrate on making sure that the way in which the transmission and distribution sectors
operated allowed gains to be passed on to consumers in terms of lower prices without loss of
service'.38

37 Reports indicate that many industrial and commercial consumers have secured price cuts
averaging 4 or 5 per cent for the year beginning April 1995. See 'Big energy users win price cuts',
38 Colin Robinson, 'Liberalising the Energy Industries', op. cit.
Regulation has certainly proved extremely difficult. OFFER has been confronted with a complicated privatisation scheme imposed on a complex industry in which many of the ‘new’ organisations are based on old ones and old relationships still persist. Moreover, the scheme failed to distinguish clearly between those activities which are naturally monopolistic with present technology and those which are potentially competitive.

For example, embedded within the long-distance ‘wires business’ of NGC are two pumped storage generating plants, Dinorwic and Ffestiniog, with a combined capacity of 2000 MW which are virtually the only plants not owned by National Power and PowerGen which have any influence on SMP (see 3.5 above). Had they been placed in a separate company, competition in generation would have been enhanced and regulation of NGC would have been more straightforward since there would have been no confusion of natural monopoly and competitive activities.39

Such confusion has, however, been much greater in the case of shorter distance movement of electricity (distribution) which was left in the hands of the RECs even though they had to account for it as a separate business. This has brought serious regulatory difficulties because of the number of functions which RECs have other than electricity transportation: they are suppliers of electricity (with monopolies of the small consumer market until 1998), suppliers of electrical appliances (in most cases), electrical contractors (in most cases), generators (in most cases) and they had, after privatisation, the ability to diversify into other areas. Thus, regulating the RECs is a much more complex task than supervising a network monopoly.

In such circumstances, the scope of regulation has been extremely wide,40 in effect covering the whole industry instead of those parts which might be regarded as naturally monopolistic. OFFER has been constantly drawn into regulating generation, an activity which could have been highly competitive and which the government evidently expected would require only minimal attention from the regulator: in other sectors its task has been complicated by the mixture of naturally monopolistic and potentially competitive functions it has had to supervise. Consequently, its resources have been diverted away from the task (difficult enough in itself) of regulating the ‘natural monopoly’ network of wires.

39 In May 1995, NGC announced a plan to demerge its pumped storage business. The idea is initially to make the business a wholly-owned subsidiary of the 12 RECs, then to float it separately. See ‘Grid plans pump storage demerger’, The Financial Times, 11 May 1995. NGC itself will be floated separately by the RECs, probably late in 1995, the pumped storage business having been divested.

Not only is the scope of regulation wide, OFFER’s powers are wide also because, as in all British privatised utilities, the Director General has a duty to promote competition (as well as issuing and modifying licences, making sure licence holders can finance their activities and similar regulatory functions). In the case of electricity the pro-competition duty is very explicit. The Electricity Act 1989 sets out one of the prime duties of the regulator (shared with the Secretary of State for Energy) as ‘...to promote competition in the generation and supply of electricity’.

5.2 Regulating generation, and new proposals to privatise nuclear power

In generation, the sector where some competition was introduced from the beginning, the complexities of the privatised system have combined to minimise the impact of competitive forces on the incumbents (3.6 above) so consumer interests have not been safeguarded: the trigger for OFFER investigations has usually been complaints from large users of electricity.

Five reports have been issued by the regulator on pool prices and related issues.\(^{41}\) None so far has resulted in a reference to the MMC which is one of the sanctions the regulator has, though such references have been threatened. Following an investigation in February 1994, OFFER placed a temporary two-year cap (until March 1996) on average pool purchase prices at 2.4 pence per kWh time-weighted and 2.55 pence per kWh demand-weighted (both in October 1993 prices), implying a reduction of about 7 per cent compared with the first nine months of 1993-94. It also insisted that National Power and PowerGen ‘use all reasonable endeavours’ to sell or dispose of 6 GW of coal-fired or oil-fired stations in order to bring into the market other generators with mid-merit or peaking plant. OFFER’s report expressed concern that ‘...the two generators have used their market power to achieve their aims of higher prices’.

Early in 1995, no plant sales had been made and a surge in pool prices (3.7 above) again brought complaints from large industrial users of electricity.\(^ {42}\) The DGES then reminded the generators of their undertakings and said he was monitoring their actions: his statement was taken to be an implied threat of an MMC reference.\(^{43}\)

Other proposals for stimulating competition in generation centre on structural changes. One opportunity for such changes was the review of the nuclear industry which the government conducted

\(^{42}\) In the year to March 1995, the demand-weighted pool price was slightly in excess of the agreed cap. See ‘Power groups face crackdown’, The Financial Times, 1-2 April 1995.
in 1994/95. Some submissions to the review argued that nuclear power should be privatised in such a way that two powerful new competitors, based on Nuclear Electric and Scottish Nuclear would be introduced into the market along with a smaller company with Magnox stations: even though it seemed unlikely that the ageing Magnox stations could be privatised, it was suggested their operation could be contracted out so that they became another competitor in the electricity market.\footnote{OFFER, Submission to the Nuclear Review, op. cit., Colin Robinson, Privatising Nuclear Power, evidence for the review of future prospects for nuclear power, September 1994.}

The competitive potential of Nuclear Electric and Scottish Nuclear is at present limited because they are state-owned, because of their inability to diversify out of nuclear power and because of geographical market-sharing arrangements. Nuclear Electric provides only baseload power in England and Wales and has not competed vigorously in the contracts market (3.7 above). Scottish Nuclear is confined to Scotland and so does not compete in either the pool or the contracts market in England and Wales. However, if Nuclear Electric and Scottish Nuclear were privatised and at the same time the two companies were made more equal in size (by a plant reallocation) and geographical constraints were removed, they could become formidable competitors for National Power and PowerGen in the pool and the contracts markets. In the course of time, the two companies would be likely to diversify and begin to compete outside the baseload market.

The government published the conclusions of its nuclear review in May 1995.\footnote{The Prospects for Nuclear Power in the UK: Conclusions of the Government's Nuclear Review, Cm.2860, Department of Trade and Industry and the Scottish Office, May 1995.} It decided that the industry should be privatised (probably in mid-1996) but that the Magnox stations should remain in state ownership, eventually becoming part of the state fuel services company, British Nuclear Fuels. It did not, however, accept the suggestion that two private nuclear companies should be formed. Instead, the plan is that Nuclear Electric and Scottish Nuclear will merge, becoming subsidiaries of a holding company located in Scotland. The new company, named British Energy, will take over one PWR and seven AGRs.

So, if the government's plans remain unchanged, there will be one large private nuclear company and one small state (Magnox) company, the latter operating for the remaining lives of the Magnox plants. Under these circumstances, despite the formation of the separate Magnox company, it seems that three companies (albeit private rather than government-owned) will continue essentially as a triopoly in the England and Wales market (see 3.7 above).\footnote{A criticism of the government's nuclear privatisation plans is in Colin Robinson, ‘Competition before cash in nuclear sale’, The Financial Times, 5 May 1995.}
5.3 Regulating the regional companies, and the effects of takeovers

As explained, distribution within each REC remains a local monopoly. Not surprisingly, it is more profitable than the supply business where competition has developed for the large consumer (100 kW and above) market. Supply to smaller consumers was initially regulated under an RPI-X + Y formula which allowed a REC to pass through (as Y) the costs of electricity purchases, transmission and distribution charges, though subject to a price cap equal to the change in the RPI. Each REC retains until 1998 its monopoly of consumers with a maximum demand of less than 100 kW - that is, virtually all residential consumers and some others. Supply should become very competitive from 1998 onwards, when all consumers have a choice of supplier, though experience when the monopoly threshold was reduced from 1MW to 100 kW in 1994 suggests that competition will for a time be hampered by metering problems.

The supply price cap for consumers with a demand of less than 100 kW was tightened from RPI-0 to RPI-2 from April 1994. Distribution charges are of more significance to consumers since, on average, they account for about one-third of residential customers’ bills. A distribution price review by OFFER took place in mid-1994, following which the regulator proposed (and the RECs accepted) one-off cuts in distribution charges, varying by REC between 11 per cent and 17 per cent, to take effect from April 1995. Subsequently, all such charges would be subject to an X term of -2: previously X had been zero or positive (up to 2 ½ per cent). Although the review was accepted by all the RECs without challenge, one of the Scottish companies (Hydro-Electric) appealed to the MMC which carried out an inquiry and reported in June 1995:

it used a different methodology from the regulator and came to slightly different conclusions about Hydro-Electric’s charges.

The 1994 distribution settlement for England and Wales was upset after less than a year when in March 1995 the regulator announced that, though the new distribution charges would stand for the year beginning April 1995, he would reconsider the proposed charges for subsequent years. The trigger for his change of view was evidently a contested bid by Trafalgar House for one of the RECs, Northern Electric. REC takeovers became possible once the government’s ‘golden shares’ expired in March 1995.

According to the regulator, he had already become concerned - because of rising REC share prices and representations made to him by consumers - that his 1994 review might have been too lax. But what convinced him to reconsider was a defence document produced by Northern Electric

in response to the Trafalgar House bid which promised big cuts in costs, special payments to
shareholders, increased gearing and substantial dividend increases. In other words, the regulator
concluded that the bid revealed new information about the costs of one REC and, by implication, all
RECs. It seemed that, if pressed, they could reduce costs much more and provide considerably
greater benefits to shareholders than had been apparent at the time of the 1994 distribution review.
Moreover, they could significantly increase gearing.

Claimed benefits of a price cap regime, with reviews every five years or so, are its stability
and the incentive it gives to regulated companies to reduce costs (because, unlike a rate of return
system, they can for a time appropriate the cost reductions in terms of increased profits). Despite
upsetting that stability and creating uncertainty - which incidentally affected the sale in early
March 1995 of the government’s remaining 40 per cent shares in National Power and PowerGen -
the regulator decided that the distribution charges he had just set must be revisited.

The new charges, announced early in July 1995, imposed significantly tighter controls on
the RECs than the 1994 proposals. Distribution charges were reduced by 10 to 13 per cent in
1996-97 (depending on the REC) and the value of X for the period 1997-2000 was increased to 3 per
cent. After the new review, the aggregate reduction in distribution charges for the period 1994-95 to
1999-2000 will vary between 27 and 33 per cent, depending on the REC concerned.

One of the most interesting aspects of the events of March 1995 and the subsequent
re-review of charges is that relevant cost information was revealed by a hostile takeover bid. Where
there is monopoly in the product market, a functioning market for corporate control will have
beneficial effects, both directly by imposing efficiency pressures on the companies concerned and
indirectly by providing information for a regulator. No matter how assiduous and determined a
regulator may be, in the absence of a market it is genuinely impossible to determine what costs
‘should’ be. The market for corporate control - which, in the case of the RECs, has only been
allowed to function since the government gave up its golden shares in March 1995 - helps to fill the
regulator’s information gap.

Even though the Trafalgar House bid itself failed - it was eventually withdrawn in August
1995 - in another sense it was extremely successful. It discovered information which would
otherwise have remained hidden, perhaps even to Northern’s management. As it was, an incumbent
management, under pressure from an alternative management team, found scope for substantial
efficiency gains and revealed them to the financial markets.

Subsequently, in the late summer and early autumn of 1995, there was a flurry of takeover
bids, some agreed and some contested, with at least six of the RECs likely to be taken over by other
companies in the electricity sector (in Britain and abroad), by water companies or by major

non-electricity companies such as Hanson.\(^5\) It seems certain there will shortly be a smaller number of (larger) regional electricity companies, and possibly some vertical re-integration of the industry since both major generators have made bids for RECs: at the same time National Power and PowerGen have agreed to make the disposals of 6 GW of generating plant which the regulator wanted (see 5.2 above).

5.4 Future regulatory concerns

There is now considerable popular concern, which may be translated into regulatory action, about the profitability of the RECs and the big increases in salaries of REC and NGC senior executives. Media attention has indeed focussed on executive salaries in all the privatised utilities. One reason for the spectacular rises is that salaries were held down under nationalisation. But there is legitimate concern that in an industry where competition is relatively weak, shareholders and managers appear to be reaping most of the benefits of privatisation at the expense of consumers. The Labour Party (with some Conservative support) has proposed a special tax on the ‘windfall’ profits of electricity (and water) companies.\(^5\)

Another issue being debated is the price cap (RPI-X) system which is one of the features of British utility regulation. The electricity regulator’s actions in re-opening the distribution price review were a blow to price-cap regulation. But there are also issues of principle. As already explained, a price cap is intended to bring stability and efficiency incentives as compared with a rate of return system. It does indeed have such effects but setting \(X\) presents problems and tends to be arbitrary in circumstances where no markets exist. British utility regulators, searching for quantitative measures which would help determine \(X\), tend to turn to profits as measures of company performance. But the more they do so, the more British price cap regulation tends to revert to rate of return regulation, reducing incentives to introduce cost savings which would raise profits (because increased profits may lead to increases in \(X\)).

One way of easing the burden of regulation would be to establish a clearer separation between naturally monopolistic and potentially competitive activities. In the case of the RECs, there would be advantages to the regulator if distribution were divested and therefore clearly separated from other functions (in the same way that transmission was separated from generation at the time of privatisation). Alternatively, the reorganisation of the REC sector which began in the summer of 1995 (5.3 above) may eventually ease the burden of regulation. The market for corporate control should both impose new pressures for increased efficiency - which, provided the product market becomes more competitive, should be passed on to consumers - and discover information for the regulator.


6. Effects on other fuel industries

The nationalised electricity supply was, as explained in 1 above, used as an instrument of government industrial and energy policies. Privatisation disturbed such policies with consequent effects on the associated industries. The impact on the coal and nuclear industries is outlined below.

6.1 Coal

Coalmining in Britain, long protected by government pressure on electricity generators to burn more coal than they wished (1.2 above), was one of the principal casualties of electricity privatisation. Because of government protection, the coal industry concentrated nearly all its efforts into selling into the power generation market: it was dangerously exposed to any change in the market for generation fuels such as the one which accompanied electricity privatisation.

Once electricity was privatised, the extent of coal’s problems became clear. It had to battle not only with the loss of government protection (after an interim period from 1990 to 1993), and with environmental regulations which significantly increased the costs of coal-fired generation, but with various sources of bias against coal contained within the new electricity supply industry.

The prime source of bias in this case, as in others analysed above, arises from the duopoly structure of generation (3 above). In a market with a number of rival generators, all with fossil fuel fired plant, in the absence of collusion each generator would invest in new plant only if it expected that the avoidable costs of the new plant (capital and operating) would be less than the avoidable costs (operating plus any incremental capital) of existing plant. Their expectations might be right or they might be wrong. But the competitive process would penalise companies which made poor fuel choice decisions and reward those which made better decisions. It would therefore provide incentives to make better fuel choices than one’s competitors.

However, in a market where all coal-fired plant has been divided between two companies, each of which is a successor of the CEGB and is therefore likely to have reasonable knowledge of the other’s costs, the competitive process is unlikely to work so well and fuel choices will probably not be the same as those which would have been made in a rivalrous market. The duopolists have sufficient market power to indulge in strategic gaming so as to maintain their own positions at the expense of potential newcomers.\(^\text{54}\)

Some bias against the use of existing coal-fired plant seems to have been one result. As explained in 3.3 above, the major generators may well have had some incentive to announce plans to build new gas plant as a means of deterring entry to generation: they know that entry will only be with gas-fired stations since they are perceived to be lower cost than other new plant. Even if their own

\(^{54}\) Robinson, Energy Policy, op. cit.
estimates suggest that it would have been cheaper to keep existing coal stations in operation, announcing such plans may serve the purpose of keeping out some competition: because of the generators’ market power, they are unlikely to be constrained from passing on to the RECs and large consumers the costs of the choices they make. Moreover, because the two major generators, between them, control the bulk of generating capacity in England and Wales, they can accelerate their plant closure programmes if capacity shows signs of becoming excessive.

Another bias in the system which arises from the duopoly and which favours the construction of new gas stations is that the RECs have an incentive to avoid the market power of the generators (3.5 above). Thus they will tend to build more new plant themselves (or sign long-term contracts with owners of new plant) than they would have done had generation been competitive. Most of the RECs have little existing generation and so they do not consider the alternative of keeping open coal- or oil-fired power stations.

The sharp decline in British coalmining which followed on electricity privatisation, and which was accentuated from 1993 onwards when the first government-inspired coal contracts ended, was therefore not simply a consequence of the industry’s suddenly being exposed to market forces. There were serious government-imposed distortions in the new electricity market which, in general, tipped the scales against British-mined coal. Coal production, which had been nearly 93 million tonnes in 1990, halved to about 48 million tonnes in 1994 and the number of miners fell from 59,000 to 7,000 over the same period. The remaining mines were privatised at the end of 1994. Sixteen operating deep mines in England and Wales and 15 strip mines were sold to RJB Mining; the small numbers of mines in Scotland and in Wales were sold separately.55

6.2 Nuclear power

The other British energy industry which received support under nationalised ownership, nuclear power, was treated more favourably than coal under the privatisation scheme. Although government funding for fast reactors was stopped and finance for longer-term research into fusion was cut,56 the existing industry continues to receive substantial protection (see 1.5 and 1.6 above). The privatisation scheme for nuclear power (5.2 above) will, however, bring this protection to an end in 1996, rather than in 1998 as originally planned. From 1996 onwards, the government intends to give no subsidy to existing nuclear plants, nor will it provide taxpayers’ money for the construction of new nuclear stations.

7. Conclusions

7.1 Early lessons

It is only five years since the British electricity supply industry was privatised after many years of state ownership and, prior to that, state regulation. It is obvious, therefore, that there has been relatively little time for the effects of privatisation to appear.

Even at this early stage, however, some lessons emerge from this attempt to privatise and liberalise a complex industry within which were previously embedded both naturally monopolistic and potentially competitive activities. The principal lesson is indeed that most of the problems which have appeared are due to the government's failure, at the time of privatisation, to make a clearer separation between these two types of activities and to ensure that in the potentially competitive sectors the privatisation scheme encouraged a competitive process to begin. Regulation of the industry has been much criticised but it is not so much the regulatory regime per se which is at fault. The strains now showing in regulation are symptoms of a more serious underlying problem - that because of the way the industry was privatised, the government has heaped too many problems on the regulator.

7.2 Some advantages of the new regime

The new regime has some considerable advantages over the old.

First, government has disengaged and decisions are less politicised (though governments still try to interfere as old habits die hard).

Second, establishment of an independent regulatory office means that a more open system of regulation prevails than under the old secretive regime when Ministers, officials and industry managers took decisions behind closed doors. It is now much less easy to sweep the industry's pricing, investment and other problems under the carpet.

Third, entry to the industry has become possible (if rather difficult) instead of being prohibited by the state as it was under nationalisation. New generators and suppliers of electricity can move into the industry, knowing that they can transmit their electricity through a network not owned by generators and distribute it through networks which, though owned by distributors, should not discriminate against them. Consequently, product market competition is increasing. As the competitive market has expanded, companies with a choice of supplier have begun to benefit from lower prices. Prices to residential consumers have fallen a little in the recent past (excluding the effect of imposing VAT): they should gain more from 1998 onwards when they can choose supplier.

Fourth, the market for corporate control now operates in electricity. There have already been considerable improvements in productive efficiency, especially in the generators, where labour and fuel costs have been greatly reduced compared with the days of nationalisation. Now that the RECs are also in the market for corporate control more improvements are in prospect.
Fifth, the old protective form of energy policy in Britain, conducted mainly by the support given to nationalised British coal and to nuclear power by the electricity supply industry, could not survive privatisation. Coal protection is now very small (regrettably, the net effect of the new regime may well be some bias against coal) and support for nuclear power is time-limited (to 1996). Electricity privatisation, despite its many flaws, was a significant step along the road to a liberalised energy market.

7.3 Deficiencies of the privatisation scheme

There has been considerable entry to generation and competition to supply larger consumers has developed. But the effect on incumbents has been remarkably small and smaller consumers have so far felt few benefits. The main reasons appear to be as follows.

The most important single reason is the failure to establish an initial structure of generation which would transform a potentially competitive sector into one where a competitive process actually flourishes. The duopolistic structure (which has turned into a triopoly as Nuclear Electric has expanded) has had both direct and indirect effects, the latter because of actions taken by the RECs to evade the market power of the incumbent generators. The initial structure of generation has interacted with the pooling system and with the contractual arrangements between entrants and RECs to channel competition away from those areas where it would have had most effect on the incumbents and most impact on prices. Moreover, the task of the regulator has been greatly complicated by the need to regulate generation: not only has regulating generation proved extremely difficult but OFFER’s resources have been diverted away from supervising the naturally monopolistic sectors of the industry.

Second, the pooling system which has caused such problems is proving very hard to reform. Imposed markets, which participants are compelled to join, find difficulty in adapting to changing circumstances. Like the pool, they tend to produce complex rules, which are for the benefit of existing participants and which act as a barrier to entering the industry. Adaptation tends to take the form of making the rules even more complicated. Proposals for pool reform have been aired for some time; it appears that agreement was almost reached in 1994 for an arrangement which would have allowed trading outside the pool but in the end the DGES would not accept it. It is not clear that any form of pooling, other than market participants would agree among themselves, needs to be imposed. But to remove an institution which was established by government and which has developed a life of its own is clearly difficult.

Third, outside generation potentially competitive activities and natural monopolies have been left in the same organisations making regulation unnecessarily difficult. NGC, which controls transmission and central despatch and settlements, contains two pumped storage generating

stations. More seriously, each REC owns its local network of wires to which it is supposed to provide non-discriminatory access. But it also engages in a variety of functions in which it competes with others - supply and, depending on the REC, appliance sales and services, contracting and generation - as well as having the ability to diversify into other activities.

Fourth, the initial supply and distribution price cap regimes were unduly favourable to the RECs which have turned out to be much more profitable than had been expected. It was, of course, extremely difficult to predict the effects on profits. But there have been regulatory consequences as OFFER has had the difficult task of trying to adjust the original settlements.

Fifth, one consequence of the weakness of competition in generation and the laxity of the REC price caps has been that shareholders and senior managers throughout the electricity supply industry appear to have been the main beneficiaries of privatisation. Media attention has concentrated on the privatised utilities so that managers' salaries, and to a lesser extent, shareholders' gains have become a topic of public discussion. The public perception of electricity is of an industry where any recent favourable effects on prices have been dwarfed by large benefits to managers and shareholders. Even though gains to residential as well as other consumers should soon appear, there is a danger that demands that the regulator or the government 'does something' will bring a new politicisation and re-regulation of the industry.

7.4 Lessons from electricity privatisation in Britain

If one regards the crucial test of a market as the extent to which it stimulates a competitive discovery process, the privatised electricity market still has many deficiencies. It is however, in my view, a considerable improvement on nationalisation, mainly since entry is now possible and has been shown to be feasible and because the companies are now in the market for corporate control. Once all consumers have the power of exit (from April 1998) the development of a genuinely rivalrous market may well be accelerated: not only will suppliers be subject to greater competition, they will put pressure on generators to bring down prices and on the regulator to reduce transmission and distribution charges. Another advantage, in my judgement, is that the new privatised market has capacity to evolve and is capable of being reformed in a way the old regime was not.

I would suggest six lessons that should be learned from electricity privatisation in the United Kingdom.

The first is the importance, at the time of privatisation, of separating natural monopoly activities from potentially competitive activities and regulating only the former. Regulation is such an unsatisfactory business that it should, in my view, be avoided wherever possible: it involves attempts to gather centrally information which is unlikely to be revealed except by market processes.

58 As explained in 5.1 above, there is a demerger plan for the pumped storage business and for the separate flotation of NGC (presently owned by the RECs).
Regulating sectors which are potentially competitive wastes valuable regulatory resources, is most unlikely to be effective and gives regulation a bad name. The area of genuine ‘natural monopoly’ needs careful consideration to avoid inclusion of any activities where competition is possible and the market should be allowed to redefine natural monopoly as technological change occurs. Too much emphasis on regulation and too little on competition will delay and reduce the gains to consumers, leading to disillusionment with privatisation and de-regulation.

Second, price cap regulation - despite the problem of determining X factors which I have mentioned and the tendency to move towards rate of return regulation - generally provides better efficiency incentives than does a rate of return regime. The regulator does, however, need to establish a stable framework of regulation which is expected to last for a period of years.

Third, an independent regulatory office has many advantages over direct regulation by government. The system is more open and less susceptible to short-term political pressures.

Fourth, giving the regulator the duty to promote competition provides him or her with a powerful incentive to stimulate rivalry and helps avoid ‘capture’ and the other problems which can afflict regulated systems if regulators are over-influenced by pressure groups.

Fifth, the market for corporate control not only directly increases efficiency pressures, as is generally recognised. In regulated industries, it also provides valuable information for regulators as different management reams vie to control companies, making public their ideas on new and more efficient ways of achieving existing goals. In general, pressures to reorganise industries arising from the market for corporate control should not be resisted unless there are very powerful anti-monopoly reasons.

Sixth, the gains from privatisation and deregulation appear over a period of many years as market entry is stimulated, the market for corporate control operates, and rivalry results in technological and managerial advances, ensuring that benefits are passed on to consumers. Such gains are essentially dynamic: they cannot be captured by calculations of static efficiency benefits which are indeed irrelevant to the case for privatisation and deregulation.
Table 1

NATIONAL POWER AND POWERGEN POWER STATIONS AT VESTING DAY

by type of fuel

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>National Power</th>
<th>PowerGen</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>GWso % of total</td>
<td>Gwso % of total</td>
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<tr>
<td>COAL</td>
<td>19.5 66</td>
<td>11.6 62</td>
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<tr>
<td>COAL/OIL</td>
<td>2.6 9</td>
<td>1.9 10</td>
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<tr>
<td>OIL</td>
<td>5.9 20</td>
<td>4.0 21</td>
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<tr>
<td>GAS TURBINE</td>
<td>1.6 5</td>
<td>1.2 6</td>
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<tr>
<td>HYDRO</td>
<td>0.1 -</td>
<td>0.1 1</td>
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<tr>
<td>TOTAL</td>
<td>29.7 100</td>
<td>18.8 100</td>
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Source: CEGB Statistical Yearbook, 1988-89, Table 11B
Table 2

GENERATOR MARKET SHARES OF POOLED OUTPUT

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<tr>
<td>National Power</td>
<td>45.5</td>
<td>35.0</td>
<td>34.2</td>
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<tr>
<td>PowerGen</td>
<td>28.4</td>
<td>26.1</td>
<td>25.3</td>
</tr>
<tr>
<td>Nuclear Electric</td>
<td>17.4</td>
<td>23.2</td>
<td>23.3</td>
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<tr>
<td>Inter-connectors</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>and Pumped Storage*</td>
<td>7.7</td>
<td>8.4</td>
<td>8.8</td>
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<tr>
<td>New entrants</td>
<td>0.0</td>
<td>6.2</td>
<td>7.3</td>
</tr>
<tr>
<td>Others**</td>
<td>1.0</td>
<td>1.1</td>
<td>1.1</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

* ScottishPower and Hydro-Electric (via the Scottish Inter-connector), EdF (via the French Inter-connector) and NGC Pumped Storage

** Mainly BNFL, AEA and renewables

Table 3

Employment in Electricity Generation

<table>
<thead>
<tr>
<th></th>
<th>Vesting day 1990</th>
<th>end March 1995</th>
</tr>
</thead>
<tbody>
<tr>
<td>National Power</td>
<td>17,200</td>
<td>5,100</td>
</tr>
<tr>
<td>PowerGen</td>
<td>9,500</td>
<td>3,700</td>
</tr>
<tr>
<td></td>
<td>26,700</td>
<td>8,800</td>
</tr>
</tbody>
</table>

Source: National Power Annual Reviews
         PowerGen Report and Accounts,
         and Press reports
CONCLUSIONS

- Early to draw conclusions, after just over five years

- But most problems seem due to two failures:

  - To separate naturally monopolistic and potentially competitive activities more clearly

  - To ensure that in the competitive areas the privatisation scheme encouraged a competitive process to flourish

- Because of these two failures too many problems have been heaped on the regulator
ADVANTAGES OF THE NEW REGIME

- government has disengaged so less politicisation

- more open regulation

- entry to generation and supply is possible and has occurred

- considerable improvements in productive efficiency

- prices have begun to fall and should fall further as the competitive supply market extends (April 1998 onwards)

- protection for the energy industries is now much reduced
DEFICIENCIES OF THE PRIVATISED MARKET

- despite considerable entry to generation and supply the impact on incumbents has been small. The two major generators, for example, are still price-makers.

- the duopolistic structure, the pooling system and contractual arrangements between RECs and new entrants have combined to channel competition away from areas where it would most have affected incumbents in generation.

- the pooling arrangements are proving hard to reform.

- outside generation, potentially competitive activities and natural monopolies have been left in the same organisation, making regulation difficult.

- initial supply and distribution price caps were unduly favourable to the RECs.

- because of the above deficiencies, shareholders and senior managers have so far been the main beneficiaries of privatisation. A new politicisation of the industry is threatened by demands that regulation should be ‘tightened’.
NECESSARY REFORMS

- curb the market power of National Power and PowerGen, by plant divestment or other means

- divest the wires businesses of the RECs from the rest and divest generating plant from NGC

- regulation would then be confined to natural monopoly networks (so long as they remain genuine ‘natural monopolies’), leaving generation and supply unregulated except for oversight by the general competition authorities
Figure 1. Prices of Fuels Purchased

Figure 2. Prices of Electricity Purchased
3. Japan

REGULATORY REFORM AND ITS EFFECT IN THE JAPANESE ELECTRIC UTILITY INDUSTRY

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Following the war, the electric utility industry in Japan was vertically integrated into nine core utilities, each devoted to a system to ensure a stable supply of high-quality electricity. Today, however, this system is undergoing gradual changes amid varying rules and deregulation that call for a more efficient system of the industry. Among the changing regulations under consideration are to liberalize entry into the electricity wholesale market, stimulate wheeling, revise rate-making system, establish direct electricity retailing in the form of specified electric utility industry, and ease safety regulations. The first drastic amendment in thirty years of the Electric Utility Industry Law is already slated.

This report is designed to consider the background and contents of deregulation of the electric utility industry currently underway. Composition of the report is as follows. Present systems of the electric utility industry and applicable regulations are reviewed (Chapter 1), followed by a discussion on why the changes are necessary (Chapter 2). Subsequently, conventional regulations are evaluated from a theoretical aspect (Chapter 3). Thus, the first three chapters deal with the background of deregulation. Then, after summarizing the contents of deregulation under consideration (Chapter 4), that extent that deregulation can produce effects on the national economy is considered (Chapter 5). The final section gives a glimpse of desirable conditions of the electric utility industry and regulation in the future.

1. Japan’s Electric Utility Industry

Major electricity suppliers in Japan can be classified into electric utilities and in-house power generators. Electric utilities can further divided into general and wholesale electric utilities. There are ten general electric utilities, each taking the form of monopoly in its service area and carrying out vertical integrated operations of generation, transmission and distribution.

The Electric Utility Industry Law (1964) governs the electric utility industry. The law specifies rules of the entry/exit of the electric utility industry, supply conditions (rate-making), supply obligation, safety, etc.

While electricity demand is expected to continue to grow, general electric utilities have various problems in securing necessary supply capacity.

1.1 Systems of Electric Utility Industry
1.1.1 Electric Utilities
(1) Category of electricity suppliers

Electricity suppliers in Japan consist of 1) electric utilities designed to sell electricity generated by themselves to a third party, and 2) in-house power producers that generate electricity to be consumed by themselves. As of late March 1994, installed generating
capacities amounted to 212.9 GW, including 190.4 GW owned by electric utilities and 22.5 GW by in-house power producers. Thus, electric utilities are responsible for about 90% of electricity supply in Japan (Figure 1).

Electric utilities are further divided into 1) general electric utilities and 2) wholesale electric utilities. General electric utilities, each given a specific service area of its own, are expected to supply electricity to meet general demand in their service area. On the other hand, wholesale electric utilities, without having specific service areas of their own, are designed to provide wholesale electricity to general electric utilities.

(2) General electric utilities

There are ten general electric utilities. They are Hokkaido Electric Power Co., Inc., Tohoku Electric Power Co., Inc., Tokyo Electric Power Co., Inc., Chubu Electric Power Co., Inc., Hokuriku Electric Power Co., Inc., Kansai Electric Power Co., Inc., Chugoku Electric Power Co., Inc., Shikoku Electric Power Co., Inc., Kyushu Electric Power Co., Inc., and Okinawa Electric Power Co., Inc. (Table 1). Until 1972, when Okinawa was returned by the U.S., the remaining nine had been responsible for the nationwide electricity supply as general electric utilities. This, popularly called the “nine-utility system,” was established in May 1951 as a result of reorganization of the electric utility industry after World War II. This system has survived to date. Individual electric utilities, privately owned and run, have their own service areas allocated by dividing the whole country land into ten blocks. The utilities are supplying electricity through vertically integrated operations of generation, transmission and distribution.

Tokyo Electric Power, the biggest general electric utility in Japan, is responsible for the Kanto area, with Tokyo as the core. It sold a total of 255 TWh to 24 million customers and earned sales proceeds of ¥4,558 billion (FY 1993). These figures hold around 34% of the ten-utility total in terms of both generated output and proceeds. Tokyo Electric Power is capable of generating 49.5 GW at maximum, the world’s second largest after Electricité de France (EdF).

Kansai Electric Power, the second largest after Tokyo Electric Power, covers the whole of Kansai, centering on Osaka. In FY 1993, the utility sold 123.3 TWh to 11.6 million customers and earned ¥2,287 billion. These figures account for around 17% of the ten-utility total. Its generating capacity amounts to 35.0 GW, of which 28% is covered by nuclear power plants. The share of nuclear is highest among Japan’s general electric utilities.

Chubu Electric Power covers the Chubu area, with Nagoya as the center. Its customers, electricity sales amount and sales proceeds are 9 million, 102.9 TWh and ¥1,898 billion, respectively, and puts the utility responsible for around 14% of the ten-utility totals.

The top three utilities alone account for 66% of the total electricity amount sold by general electric utilities (FY 1993), and their combined share has been on the rise year by year. Major reasons for the rise are various functions concentrating in urban areas, and
heavier electricity demand by residential/commercial users, as opposed to instead of industrial. In addition, because their supply capacity is insufficient, the three utilities are becoming increasingly dependent on external supply capacity outside their areas.

(3) Wholesale electric utilities

Apart from the Electric Power Development Co. (EPDC) and the Japan Atomic Power Co. (JAPC), wholesale electric utilities include twenty joint-ventured thermal power plants and thirty-four municipal electric utilities. EPDC, the largest wholesale electric utility in Japan, was founded in 1952. At the time of its establishment, electricity demand was so strong that nine electric utilities were forced to increase their supply capacity. But, because of financial difficulties, they could hardly meet the need. Therefore, EPDC, funded 99% by the government, was inaugurated as the machinery through which massive national funds were funneled into power resources development projects.

JAPC on its part was established in 1957. Jointly funded by nine electric utilities, EPDC and industry, JAPC was expected to commercialize nuclear power generation by importing commercial-size reactors to generate electricity. Meanwhile, many of the joint-ventured thermal power plants were established during the postwar high-growth period with joint investment between steel makers, industrial users, and electric utilities. In addition, municipal electric utilities, run by municipal governments, have power plants to put local water resources to effective use. They all specialize in hydraulic power generation.

As of March 1994, general electric utilities (10) have 1,352 power plants and 163.5 GW in peak output; wholesale electric utilities have 406 plants and 26.9 GW. When combined, installed generating capacity owned by electric utilities amounts to 190.4 GW at a total of 1,758 plants. Thus, of electric utility totals, general electric utilities hold 77% in plant number, and 85% in generating capacity.

1.1.2 In-house Power Producers

(1) In-house power generation/consumption

As of March 1994, in-house generating facilities are installed at 2,185 sites and amount to 22.5 GW, responsible for around 10% of Japan’s total generating capacity. Major in-house power producers are found in the paper/pulp, chemical, steel and petroleum refining industries. Many are generating electricity as a by-product from the steam production necessary for manufacturing processes, or committing to in-house power generation in order to reuse energy sources generating from their manufacturing processes as by-products. But, enhanced energy conservation spurred by two oil crises helped strengthen in-house generating capability as a measure of energy recovery.

In 1993 in-house power generation covered 28% of electricity needs among industrial users, and the ratio has been kept high after the second oil crisis.
(2) Specified supply projects

“Specified electricity suppliers” are non-general electric utilities which are allowed to retail electricity directly to end users within a designated area while taking the form of in-plant power producers. A MITI ordinance shows patterns of such electricity supplies to end users as follows:

1) Electricity supply by municipal organizations to other municipal departments of their own.
2) Electricity supply to those who have close relations through investment, etc.
3) Reciprocal electricity supplies among those who are closely related in production processes, like inter-company supplies among those composing of an industrial complex.
4) Electricity supply to company housing.
5) Electricity supply by the owner of a building to meet demand within the given building.

As of late March 1994 specified supply projects numbered 1,307, under which 34.9 TWh was supplied with 5.8 GW of licensed generating capacity. These figures represent a mere 4.9% and 3.0%, respectively, to the portion covered by the electric utility industry. Also, supply capacity per project is as limited as 4.3 MW. Nonetheless, now that highly energy-efficient co-generation has been employed as their supply technology these years, these projects attract growing attention from the aspect of the national economy.

While four major sources of electricity supply are described above, the electricity supply system in recent years is also called the “composite electricity supply system.” The system consists of 1) general electric utilities obliged to offer comprehensive supply services, 2) wholesale electric utilities, 3) in-house power producers, and 4) “specified supply projects.” Changing regulations currently underway are unlikely to open the door of general electric utilities, but the entry of independent power producers (IPPs) into the wholesale market, expansion of specified supply projects, etc. are taken into the field of vision.

1.2 Regulations of Electric Utility Industry

1.2.1 Grounds for Regulation

The reasons why behaviors of electric utilities are restricted by regulation can be interpreted as follows:

1) Inherent monopolistic nature of the electric utility industry
2) The essential and public nature peculiar to electricity as goods
3) High risks of the project which involves huge investment
4) National security
5) Safety problems

These concepts have been taken over to the existing “Electric Utility Industry Law.”
As a result, from the aspects of effective utilization of resources and security of stable supply, 1) regulations of entry and 2) regulations of exit are provided based on the supply/demand balance principle. Also, 3) rate-making regulations (supply conditions) are provided in order to avoid the demerits of monopoly, and 4) safety regulations are specified as social regulations, among other things.

1.2.2 Electric Utility Industry Law

(1) Objectives

The Electric Utility Industry Law (1964) provides grounds for official regulations of the electric utility industry (Figure 2). It was an amended version of the Electric Utility Industry Law (1911) to help reorganize the electric utility industry after World War II, while reviving the regulatory ideas of 1) operations and 2) safety of the previous law. Objectives of the amended law are 1) protection of electricity consumers, 2) sound development of the electric utility industry, 3) security of safety, and 4) pollution abatement (Article 1).

(2) Entry-related regulations

Article 3 describes words entry-related regulations first. It provides that electric utility operations requires a license issued by the Minister for International Trade and Industry. Criteria employed by the MITI Minister in issuing the license are as follows (Article 5):

1) The start of operations meets demand.
2) In the case of a general electric utility, its supply capacity meets demand.
3) If a general electric utility plans to start operations, the supply capacity should not represent double or excessive investments within its service area.
4) The operator should have accounting/technical capabilities in carrying out the operations.
5) The plan for operation should be firm.
6) The operations should contribute to public interests.

In fact, general electric utilities have managed their business operations in the form of regional monopolies. But, it is not because the law specifies a franchise by a utility in an area, but because the system resulting from the “supply/demand balancing clauses” shown in 2) and 3) above, combined with the postwar reorganization of the electric utility industry, and have made it practically hard for newcomers to become general electric utilities. However, in Article 21, the Anti-Monopoly Law cites railway, electric and gas utility services as business operations which tend toward natural monopolistic behavior, from which provisions of the Anti-Monopoly Law are made clear.

Criteria to permit the entry into the wholesale market are pursuant to 4), 5) and 6)
above. After all, those who hope to enter the market are required to obtain a license issued by the MITI Minister.

In addition, “specified supply” projects exist in the service area of general electric utilities, and are engaged in retailing to limited customers. Each specified supply project is required to obtain a license from the MITI Minister, and the primary qualification is that the entry won’t harm the interests of general customers supplied by general electric utilities (Article 17).

(3) Leave-related regulations

Just like the entry into markets, leaving needs an approval of the MITI Minister (Article 14). The leave can be approved on condition that there is no fear of hurting public interests.

(4) Supply obligation

In return for virtually guaranteed regional monopoly, general electric utilities are imposed a supply obligation to prevent monopolistic demerits. Namely, they “are not allowed to refuse electricity supply to meet general demand in their service area without justification (Article 18).” In addition, standards for rate calculation as well as rate levels are subject to regulations.

(5) Rate-making regulations

Electricity rating too is a matter subject to the MITI Minister’s approval. Rate-making and supply conditions for general electric utilities are provided by Article 19 of the Electric Utility Industry Law, and those for wholesale electric utilities, by Article 22.

Article 19 provides that “general electric utilities shall lay down supply rules of electricity rates and other supply conditions, which need to be approved by the MITI Minister.” And, there are three principles of rate-making: 1) cost-base method, 2) the principle of fair returns, and 3) the principle of fairness to customers.

On the other hand, rate-making by wholesale electric utilities, though required to recover costs, can be managed more flexibly than in the case of general electric utilities (Article 22). But, the Electric Utility Industry Law provides no rules of rating-making applicable when “any parties” other than electric utilities wholesale to general electric utilities, like a case where an in-house power producer wholesales its surplus generated output to a general electric utility.

(6) Other regulations

Besides the regulations of entry/exit and rate-making outlined above, the Electric Utility Industry Law contains side-business regulations (Article 12), broad-area operation (Article 28), accounting/financial rules (Articles 35-40), safety regulations (Articles 41-47), public
utility privileges (Articles 58-65), etc.

(7) Regulatory authorities

The government office responsible for regulating the electric utility industry is the Public Utilities Dept. of the Agency of Natural Resources and Energy. Meanwhile, in drawing up important policies of the electric utility industry, key roles are played by 1) Electricity Utility Industry Council and 2) Advisory Committee for Energy, the both in the capacity of advisory bodies to the MITI Minister.

1.3 Electricity Supply and Demand
1.3.1 Electricity Demand

(1) Historical trends of electricity demand

In Japan electricity demand has been growing year by year, despite three exceptional declines in the past (Figure 3). It was during the two oil crises (1974 and 1980) and the strong yen recession in 1986 that when the demand abated.

Real GNP elasticity of electricity demand has been larger than 1, and averaged 1.26 between 1965 and 1979. Though having slowed down in the first half of the 1980s after the second oil crisis, elasticity has continued to grow at a faster rate than GNP since 1987 (staying at 1.16 in 1987-93).

Energy demand overall has slowed down since the first oil crisis, but electricity demand alone has remained relatively strong. It reflects the factors below.

In the industrial sector, 1) growing high-tech industries, like semiconductors, have offset falling electricity demand from sluggish material-producing industries; 2) advancing factory automation (FA) at individual factories, above all, automation/rationalization investments to streamline domestic production made after the yen started rising in the mid 1980s, resulted in additional electricity consumption; and 3) an increasing number of more functional air conditioners has been introduced to improve the environment of employees.

Major contributors in the residential sector are 1) the number of households kept constantly growing at 1.3%/year; 2) possession of more than two refrigerators, TVs and other electric appliances each; 3) larger/more functional electric appliances; and 4) appliances run for longer hours by those who put them on while doing other things or by midnight users.

In the commercial sector, 1) expanding commercial floor areas of office buildings, etc. which reflect the advancing inclination of the economy toward services, 2) spread of computers and air conditioners in part due to office automation, 3) extended business hours, including 24-hour shops, and 4) greater use of lighting as decoration in such forms as lighting-up and illumination, among other things, can be cited as principal contributors to the growing electricity demand.

In 1993, residential and commercial uses held 29% and 19%, each, of the total
electricity amount sold by electric utilities. When combined, they were responsible for about half of the total, up around 10 points compared to a decade ago (Figure 4).

(2) Sharply rising ratio of in-house power generation

In 1993 in-house power generation/consumption amounted to 95.5 TWh, and accounted for 11.9% of total electricity demand in that year (Figure 5). The ratio has been on the constant rise since 1983. The ratio of in-house power generation is even higher among large industrial consumers, up from 19.6% in 1982 to 26.6% in 1993.

Major industries with high in-house power generation ratios are petrochemicals at 71% (in 1993, hereinafter the same), chemical fibers 68%, paper/pulp 68%, and petroleum products 65%. These industries all have manufacturing processes which require steam in large quantities. The in-house power generation ratio among BF-based steel makers remains at 43%, because many of them have joint-ventured thermal power plants invested jointly with electric utilities. Cement makers, which had once depended on purchased electricity from electric utilities to cover almost the whole of their electricity needs, increased the in-house power generation ratio to 45% by now.

Factors behind the rising ratio are: 1) growing electricity production as a result of diminishing steam needs in manufacturing processes, 2) installed process to produce electricity from recovered exhaust heat, and 3) improved economics of in-house power generation, thanks to sluggish international energy prices and lowered primary energy prices by the strong yen.

(3) Worsening load factor

It is noted that growing residential/commercial electricity demand is paired with a worsening load factor. Air-conditioning uses, namely, space cooling and heating, which occupy a massive portion of residential/commercial demand, do not represent a constant daily or yearly load.

Above all, the surging peak power in summer during the past few years has caused electric utilities to face difficulties in securing enough supply capacity to meet the demand. Spiraling peaks can be attributed to a growing number of air conditioners in use these years, which results in increased space-cooling demand. In the background, there is a pursuit to amenity backed by rising income.

Annual-load factor, on a gradual decline throughout the 1970s and the 1980s, fell below 60% (nine-utility average) by the mid 1980s. Amid the oppressive heat in 1992, it stood at 56% (Figure 6).

It is projected by many forecasts that electricity is likely to keep growing ahead more constantly than other energy sources. Social trends, like information orientation, aging, and many working women in the society, as well as enhanced inclination toward safety, amenity and cleanliness, all point to electricity as the preferred choice. Then, without any measures
taken, the load factor could further drop due to growing share of residential/commercial uses of which the load factor features sharp fluctuations.

1.3.2 Supply Structure

(1) Power resources mix

Japan’s electricity supply structure has been “hydro supplemented by thermal” up to the 1950s, which reversed to “thermal supplemented by hydro” in 1962, when thermal power generation outstripped hydro. Moreover, it was oil thermal power that played a key role there. Oil thermal power met the needs of the high growth period of the 1960s when the economy and electricity demand both rapidly expanded. Namely, oil-fired thermal power plants, characterized by 1) a short lead time to construction, 2) cheapness, 3) large capacity to be built if necessary, matched the needs of the era.

In 1973 the nine electric utilities depended on oil thermal power generation as much as 67% in generating capacity, and 74% in generated output. At that time, nuclear held a scant 2%-short of generated output, and coal thermal power produced by burning indigenous coal did only 6%. Natural gas (LNG) thermal power was negligible.

But, after being hit by oil crises twice, “oil-less“ moves have rapidly unfolded. With the oil crises as a turning point, the policy authorities guided electric utilities to shift to non-oil power resources, while oil thermal power concurrently became economically expensive. As a result, power resources have rapidly diversified to include nuclear, natural gas and coal, and other forms. In 1993, the weight of oil thermal power was a mere 19% in generated output (nine utilities). And, shares of nuclear, LNG and coal thermal power have expanded to 34%, 29% and 8%, respectively (Figures 7, 8). All general electric utilities except Okinawa Electric Power have nuclear power plants.

(2) Characteristics of power resources development

While electricity demand keeps growing, it is becoming harder to secure power resources to bolster supply capacity.

The security of additional electricity supply capacity is not always favorably under way, in part due to the PA (public acceptance) issue, and of nuclear power generation above all. Local residents are showing a more vehement rejection than ever against any plans to build general industrial facilities, including power plants, in their backyard.

This is reflected in the recent trend that power plants are being built in increasingly remote sites from consuming area. This requires massive transmission networks from power plants to consuming areas. Installation of these networks is actually under way, and power plant construction involves a longer lead time (Figures 9, 10). Above all, these are true of nuclear and coal thermal power, which are large-size power resources. It is because 1) appropriate sites are absent near urban areas where consumers are present, and 2) those who live in urban areas defy any attempts to locate generating facilities in their neighborhood,
among others.

Here revealed is a composition of power resources development which features consuming areas concentrating in metropolitan cities and supply sources located in sparsely-populated remote areas, and are connected with massive transmission networks. These trends of power resources development have brought about growing costs in securing an supply capacity.

In addition, electric utilities having big cities in their service areas are facing difficulties in finding sites for new power plants in their own service areas. As a result, they have no choice but to employ “board-area operation” under reciprocal cooperation in such forms as 1) power resources development overriding conventional service areas, and 2) electricity sharing with other electric utilities.

Meanwhile, a spiraling peak urges possession of generating facilities, which run as briefly as a few hours a year at longest. Due to a characteristic inherent to electricity -- it cannot be stored-- it becomes necessary to build as much capacity as required to meet a surging peak. Spiraling peaks worsen the utilization factor of overall capacity, consequently pushing electricity rates up.

Given these rate increase pressures, measures need to be taken on both demand and supply sides. Demand-side measures under way include a campaign for electricity conservation and load management by varying rates. Apart from the broad-area operations already mentioned, supply-side measures include purchasing of surplus output from in-house power plants and elastic expansion of specified supply projects.

(3) Equipment investment and financial structure

The Japanese electric utility industry invests ¥5 trillion a year in equipment. The net worth ratio (retained profit, capital increase, etc.) has dropped from 80% in the late 1980s to 65% in the last few years. In short, the industry is as debt-prone as raising 30-40% of investment funds from corporate bonds/borrowings.

Due to such huge equipment investments, the outstanding balance of corporate bonds and long-term borrowings (outstanding fixed liabilities) has swollen to ¥25 trillion by late March 1994. Also, the net worth ratio to gross asset is 15% (total capital/liabilities + capital), much lower than the average of whole industries and/or manufacturing at 30-40%.

It attributable to 1) the industry had no choice but to make larger equipment investment than the funds on hand; 2) investment itself features a long period of conception; and 3) heavy weight is constantly held by construction in progress.

Expansion of these equipment investments also causes changes in the cost structure of rating. In short, capital costs are on the rise in the form of growing depreciation costs, interest paid and repair costs resulting from equipment investment. In FY 1993 the share of capital costs (total of the three items aforementioned) in rating costs was 42%, the largest among all the expenses (Figure 11). Conversely, thanks to the rising yen and increasing
nuclear share in recent years, the weight of fuel costs has been on the gradual decline, reaching a low 13% in FY 1993.

2. Industry’s Subjects for the Present (Needs for Deregulation)

2.1 Pressures of Deregulation

Entering the 1990s, requests for deregulation of the Japanese electric utility industry have rapidly increased. The reasons can roughly be summarized in three points (Figure 12).

First, there are urgent needs for efficient electricity supply and resultant rate cuts. The move was triggered by the recession since 1991 and the rising yen’s value since 1993, which worsened the recession. For manufacturing industries, the recession at home helped intensify competition in the domestic market, and the strong yen deprived them of their price competitiveness on the international market. To restore competitiveness in markets at home and abroad, individual firms are striving for cost reduction and restructuring.

However, they have concurrently recognized that there were problems that could not be overcome through company inside efforts alone to improve their efficiency. A typical problem is big differentials between the products supplied by certain industries shipping only to domestic market and their overseas counterparts. Electricity is among them. In this way, differentials between domestic and overseas electricity rates are questioned by growing voices from industry, particularly manufacturing.

The second problem involves both supply and demand of electricity. As already mentioned, demand expansion centers on residential/commercial uses in urban areas. This type of demand features a sharply fluctuating load on not only a daily but seasonal basis. On the other hand, supply-side measures have centered, for years, on the development of large-size power resources. Unfortunately, such power resources require a longer lead time from planning to commission, and power plant sites are located more and more remote from demand. Hence, rising costs appear inevitable in the years to come.

However, technologies of electricity supply from other than big-power resources have already been commercialized. They are decentralized power sources represented by cogeneration. Effective utilization of existing in-house power generation is also under consideration. Though not large in size, these can be located near specific consuming areas and attract attention as generating forms which can contribute to effective energy use.

These two points form direct factors to prompt deregulation of the electric utility industry. Apart from them, the third reason for deregulation can be expressed as “winds of deregulation.” These same winds are blowing worldwide. They are winds to call for the reform of economic structure naturally resulting from maturity of the Japanese economy. To attain economic structural reforms, conventional industrial policies need to be changed to better match the times. The change of regulations has been increasingly requested as a viable step toward the goal. The request is not limited to the electric utility industry, but
common to public utilities overall and the agricultural/distribution sectors.

Comprehensive reviews on regulation are called for from this aspect. The subsequent section deals with rating and supply/demand problems in details to confirm their real state.

2.2 Rate-making Issues

2.2.1 Rate Levels

(1) Differentials between domestic and overseas rates

Japan’s electricity is certainly more expensive than in major countries if compared by using exchange rates. Looking at 1993 figures with Japan taken as 100, the US was 77, Britain 65, France 59, and Germany 73 (Figure 13).

The big differentials between domestic and overseas electricity rates are attributed to the sharply appreciated yen on the exchange rate. Indeed, if compared on local currency basis how much electricity rates were increased in 1980-93, it is found that Western countries raised rates by around 30-80%, while Japan cut its rates by about 13%. Also, if compared with price increase rates of general goods (ex. comparisons with CPI or WPI), electricity tariffs are falling in relative terms.

A study (1995. 1. 26) of the Rate-Making Subcommittee of the Electric Utility Industry Council points out six reasons why Japan’s electricity rates are higher. They are: 1) appreciated depreciation costs of the past equipment investment due to the rising yen; 2) rising equipment costs due to high demand growth, 3) falling annual load factor (utilization factor of capacity) due to spiraling summertime peaks, 4) inflated wages by the strong yen, 5) environmental investment and high fuel cost needed to achieve stringent environmental standards, and 6) land-related constraints.

However, these cannot justify differentials at home and abroad to be left intact. The differentials are causing serious problems to export industries. General consumers on their part still strongly feel that electricity is more expensive (Figure 14).

In fact, the problem of domestic and overseas electricity price differentials stems from the fact that efficiency improvement by the electric utility industry fails to catch up with the pace of yen’s appreciation. Export industries manage to retain their price competitiveness even hit by the strong yen, because they have adjusted their own productivity and production factor prices to the pace of the yen’s appreciation. From this standpoint, it is often argued that the problem of domestic and overseas differentials is a problem of gaps in productivity among domestic industries.

Actually, even if the environment of the Japanese electric utility industry may be different from that of its overseas counterparts, the industry is surely behind major manufacturing industries at home in such terms as capital cost and rate of productivity improvement.
Electric utilities and in-house power generation/cogeneration

There is a problem that electricity sold by electric utilities is more expensive than that produced from in-house power generation and cogeneration. Indeed, an increasing number of in-house power plants can be attributed to the better economics of in-house power generation.

For instance, the strong yen made overseas coal and oil available for less than ever. Those who practice in-house power generation can take advantage of the strong yen in the form of falling fuel prices. As a matter of course, given differences between in-house power producers and electric utilities in sitting, costs incurring in environmental/security control, and technical elements of transmission grids, a simple cost comparison is prohibited.

However, electricity rates at the end-user level are becoming more expensive than in-house power generation due to the strong yen. This is also true of cogeneration. (Figure 14)

2.2.2 Rigidity of Rating

(1) Regulation of fair returns

There are many discontents and arguments of the electricity rating system itself. With the existing rating system, electricity rates are set by adding fair returns to the supply costs. Some criticize that the regulation of fair returns can induce inefficient production in theoretical terms. It is the so-called Averch-Johnson effect (1962).

Corroborative studies on the Japanese electric utility industry have not produced a solid conclusion in regard to the A-J effect. However, at least it is certain that the present rating system does not contain any incentives to enhance production efficiency.

(2) Market efficiency

The shortcomings of the present rating system from the standpoint of market efficiency cannot be overlooked.

Electricity consumers are manifold, ranging from residential/commercial to industrial. Rating levels applicable to individual consumers are then distributed according to consumers’ characteristics by expense item. It is the called fully distributed cost (FDC) method. At a glance, this method looks fair. But from such standpoints as production factor and optimal distribution of resources, it is not necessarily fair.

Theoretically the second best rate-making system from a market efficiency aspect for the case where the cost plus returns are guaranteed, namely, after the restraint is imposed to secure a balance, is the so-called “Ramsey pricing.” The greater dissociation of actual rate levels from the Ramsey price implies greater damage given to social welfare. A collaborative study by Matsukawa et al (1993) suggests such a possibility.

On top of the employment of FDC method, all the rates set by consumer group are subject to approval of the regulatory authorities. This makes elastic rating harder for electric utilities.
(3) Growing regulatory cost

Thus, a rate-making system based on fair returns regulation and FDC, combined with meticulous approval procedures taken by regulatory authorities, has proved very much time- and labor-consuming for both the electric utilities and regulatory authorities alike. Indeed, an asymmetry of information can emerge between electric utilities and regulatory authorities. In order to balance this asymmetry, examinations by the regulatory authorities can become even more time-consuming.

Every time rates are revised, electric utilities must allocate hundreds of their employees to relevant works for a few months. The regulatory authorities, for their part, work hard for checking, and often work without sleep or rest. Naturally, details of expenses are never disclosed to the public at large.

Consequently growing regulatory costs, as well as their complexity and opaqueness, precipitates discontents of existing rating system.

(4) Rising ratio of capital costs

From the cost of rates of the electric utility industry, rising capital and repair costs can easily be noted. As already pointed out, it stems from 1) prolonged lead time of power plant construction, 2) plants located increasingly in remote sites, 3) resultant needs for giant transmission networks, and 4) deteriorating utilization factor due to falling load factor, among other things.

Under present conditions, the fuel cost favorably affected by the strong yen holds a mere 13% of the cost. The greater share held by capital-intensive and less fuel-cost-intensive power sources, like nuclear, means an ever-rising ratio of capital costs. While raising capital overseas is becoming gradually popular, an overwhelming portion of funds has been raised at home so far.

In such a situation, while the environment urges the economy to link itself with its overseas counterparts, electricity rates alone head further toward cementing rigidity.

2.3 Supply and Demand Problems
2.3.1 Problems on Demand Side
(1) Growing residential/commercial demand

Growing residential/commercial demand means sharp load fluctuations on not only daily but annual basis. Above all, growing air-conditioning use of residential/commercial demand in recent years poses a crucial problem to form peak load in summer and winter. As a result, a recent trend is that system peak load (kW) grows higher than electricity demand (kWh). This is because summertime air-conditioning load for commercial/residential uses is expanding. Taking annual average growth rates in FY 1986-92 as an example, system peak load grew 6.6%, compared with a 4.6% rise in electricity amount sold by electric
utilities.

(2) Worsening load factor

Due to these tendencies, the average load factor (net: average power load/peak 3-day average) among nine utilities has deteriorated year by year to 56% in FY 1992. However, due to a combination of recession and a cold summer, the system peak load was not renewed in FY 1993 and the load factor stood at 59.2. Thus, rising residential/commercial demand and resultant worsening load factor have formed rate-increase pressures.

As demand control measures to level the load, (a) rating system-based incentives, (b) development/introduction of heat accumulators, etc. have been in put in practice. In regard to industrial consumers, thanks to the introduction of different rates by time zone, interruptable contracts, supply/demand adjustable contracts, and other factors, rate-making systems designed for load adjustment have functioned effectively recently. A time-of-use rating system was also introduced in January 1988 for large industrial customers.

But, residential/commercial customers are not yet sufficiently provided for. For instance, the time-of-use rating system applicable to residential customers, tentatively introduced in November 1990 and evolving into full-scale introduction in June 1992, won a mere 100,000 contracts or so, or 0.2%-short of overall customers.

2.3.2 Problems on Supply Side

(1) Power resources development

The most serious problem on the supply side is the difficulties in power resources development which stem from PA(Public Acceptance) issue. For this reason, the lead time from planning to commissioning a newly-built power plant is prolonged. This is true not only of nuclear but of coal thermal power as well.

Moreover, new sites are located increasingly in areas remote from consuming areas; this requires installation of long-distance transmission networks.

(2) Safety regulations

Existing safety regulations too remain unchanged from those set in 1964, without reflecting 1) technical advances to date, 2) improved safety records, 3) the advent of decentralized power sources, and 4) changing consumer needs. The sense that existing regulations are outdated can never be wiped out (Figure 15). It is reported that the charges paid by Japan’s electric utilities to heavy electric machinery makers are nearly double that is paid by their overseas counterparts. The higher charges result from excessive safety regulations, which in turn push electricity costs up.
3. Evaluation of Conventional Regulations

Based on present regulatory conditions and performance of the electric utility industry as discussed so far, existing regulations need to be evaluated first.

At the least, the postwar system of the electric utility industry can highly be evaluated regarding following points. First, electric utilities have constantly supplied highly reliable, top-quality electricity. Second, they have achieved high efficiency in technical terms as demonstrated by generating efficiency. Third, they have provided models of pollution abatement.

On the other hand, however, some claim that existing regulations impede efficient electricity supply. Some of the emerging problems from the electric utility industry have already been pointed out. Therefore, this section picks out only the essential problems of regulating the electric utility industry. They are regulations of entry and rate-making, and evaluation of yardstick competition under regional monopoly.

3.1 Economy of Scale

General electric utilities are allowed to be regional monopolistic operators because their business operation is regarded as a natural monopoly. To organize the inherent monopolistic nature, subadditivity of cost is a necessary condition. “Economy of scale” which traditionally has provided the grounds for natural monopoly is included in subadditivity, and is a sufficient condition to justify inherent monopoly. Hence, the grounds for whether it is necessary or not to allow a regional monopoly for general electric utilities are verified from the standpoint of economy of scale.

3.1.1 Reviews on Past Studies

There are numbers of studies designed to verify if economy of scale exists in the case of Japanese general electric utilities (Table 2).

Their essence is outlined below. First, limiting to the generating sector, Izawa (1983) judged from data on the 1979-81 period that economy of scale existed. However, Awata et al (1987) denied its existence based on 1969-84 data. Furthermore, based on their calculation of 1966-84 data, Nakanishi/Ito (1988) argued that economy of scale was there but turned to nil later within the period of data studied. Then, Shinjo/Kitasaka (1989) in their study on 1975-85 data, concluded that there was economy of scale on the average, which, however, disappeared in the case of large-size firms.

Also, calculations were made on overall corporate management, covering transmission, distribution, and administrative sectors, in addition to the generating sector, the results are as follows. Nakanishi/Ito in their study judged there was economy of scale even at the level of overall corporate management. Conversely, Shinjo/Kitasaka doubted its existence and concluded in their study that a limited number of high-ranking firms could enjoy economy of
scale, but others of middle-standing or lower could be dominated by poor economy of scale.

Given a summary of these demonstration studies, it appears that there is no choice but to question the presence of economy of scale in the electric utility industry at both levels of generating sector and overall corporate management.

As done in these studies, an attempt is made below to verify economy of scale in the industry by using the latest (1976-93) data.

3.1.2 Model

Following former examples, the model in use employs production function of trans-log type; its twin, cost function, is used in actual estimation. Putting generated output as \( Q \), and, of input production elements, labor as \( L \), fuel as \( F \), and capital as \( K \), production function can be expressed as follows.

\[
Q = f(L, F, K)
\]

Assuming that an electric utility, under rating regulation, behaves to minimize total cost while satisfying electricity demand \( (Q) \), which is exogenously determined, total cost \( (LTC) \) can be expressed as follows.

\[
LTC (\text{total cost}) = g(PL, PF, PK, Q)
\]

\( PL: \) Wage rate  
\( PF: \) Fuel price  
\( PK: \) Capital service price

At this point, SCE, a yardstick to measure economy of scale, is expressed as follows.

\[
SCE = 1 - \left\{ \frac{\partial \ln LTC}{\partial \ln Q} \right\}
\]

Where \( SCE > 0 \), there is economy of scale.

Meanwhile, total cost function of trans-log type is expressed as follows.

\[
\ln LTC = \alpha_0 + \alpha_q \ln Q + \frac{1}{2} \beta_{qq} (\ln Q)^2 + \sum \alpha_i \ln P_i + \frac{1}{2} \sum \beta_{ij} \ln P_i \ln P_j + \sum \beta_{ai} \ln Q \ln P_i
\]

In order to satisfy conditions of symmetry of two-story partial differential, and of homogeneity of price, the following restraints are imposed on individual parameters.

\[
\begin{align*}
\langle \text{symmetry} \rangle & \quad \beta_{ij} = \beta_{ji} \\
\langle \text{homogeneity} \rangle & \quad \sum_i \alpha_i = 1 \\
& \quad \sum_i \beta_{ii} = \sum_i \beta_{ij} = \sum_i \beta_{ji} = 0 \\
& \quad \sum_i \beta_{ai} = 0
\end{align*}
\]
3.1.3 Estimation Results

Outlined below are results of the estimation made by using the aforementioned model. As for thermal power generation, with some exceptions for Hokkaido, Hokuriku and Shikoku, the SCE of other companies are positive, and means that economy of scale exists (Table 3). And looking at the coefficient by years, recent figures are becoming larger than those of the past. This might be caused by the stagnant fuel prices after the mid 1980s.

However, as for nuclear power generation, most of companies' SCE are negative, without Kansai and Kyushu. Therefore, at least economy of scale in nuclear power generation is very uncertain.

In terms of overall corporate management which covers transmission, distribution and administrative sector on top of generation, the SCE of most of companies are slightly positive, with the exception of Hokkaido, Tohoku and some years of Kyushu (Table 4). Looking at the figures by time series, value is improving a little. This is also probably related to fuel prices.

In summary, we estimate that economy of scale in the electric utility industry exists in some form, with the partial exception of the nuclear power generation sector and some companies.

3.2 Rating Levels and Market Efficiency

While the existing rating system employs a customer-by-customer FDC method, it is feared that the method damages economic welfare. For a firm offering a number of services, like an electric utility, there is the Ramsey price as a pricing system designed to maximize economic welfare under the condition of balance restraint.

Matsukawa et al (1993) in their study divided electricity demand into residential and industrial uses, and calculated the Ramsey price by estimating price elasticity and marginal cost of electric utilities. Comparing the estimated Ramsey price and the present rating levels, they concluded that unit price for residential customers should be higher than that at present, while that for industrial customers can be much cheaper (Table 5).

3.3 Yardstick Competition

Have general electric utilities, for which regional monopoly is allowed, endeavored to improve their corporate management through inter-industry competition by comparing their performance with that of other utilities? This is a question which involves the issue of yardstick competition among electric utilities. The conventional regulatory system contains no mandatory rule to deny the concept. Therefore, the question raised above is not a
question designed to evaluate regulatory results of the past, but rather a question directed to
electric utilities, which asks them if they have made such voluntary efforts. But, if it is
confirmed that yardstick competition does function, even on a voluntary basis, it would mean
for regulatory authorities that they are allowed to conduct market research as a step to
introduce new regulatory instruments.

As a collaborative study on the yardstick competition in the Japanese electric utility
industry, the study by Ito/Miyasone (1994) is viable. According to them, the fact that
differentials among the nine utilities have gradually narrowed in cost terms (up to 1985) can
be taken as an outcome of competition.

Technical improvement and quality competition have functioned more effectively.
Individual utilities have uniformly attained high levels of technological introduction, which
led to unmanned power plants, improved thermal efficiency, sharply lowered transmission
losses, and thunder-proof/saline-proof distribution facilities. Also, a very limited outage,
measured in both number and duration of blackouts --as well as stability of voltage-- proves
that Japan's utilities have reached the world's top level in quality of electricity. As far as
corporate management efficiency is concerned, however, it is not certain if competition has
worked or not.

These results can be thought of as the highly successful outcome of the efforts made by
individual utilities, by comparing their own data with those of others in various fields.

However, it can also be argued that the successful outcome is due to the regional
monopolistic system, which enabled individual utilities to invest in technology and quality
without paying enough attention to cost/benefit. It is sometimes pointed out that quality of
Japan's electricity is higher than necessary. Likewise, as indicated by many experts (Vickers,
J. and G. Yarrow (1988), an outcome of “possible conspiracy” can also be read from the
narrowing differentials of rates, regardless of whether the parties concerned were conscious
of it.

At any rate, it is a solid fact that the yardstick competition among nine utilities has
functioned very well in the phase of technology and electricity quality, and that it has worked
in narrowing regional differentials in the phase of rate. Nonetheless, verification has
remained insufficient in regard to management efficiency.

From the standpoints above, of conventional regulatory outcome can be summarized as
follows. First, the conventional system helped realize a stable electricity supply, and also
contributed to the development of Japan. Second, economy of scale in the generating sector
has reached its limits, and it is uncertain if economy of scale can be expected for overall
corporate management. Third, the current rate system hinders market efficiency and fourth,
while general electric utilities are allowed a regional monopoly and given service areas of
their own, yardstick competition has functioned reasonably.
4. Deregulation Under Consideration

The contents of deregulation of the electric utility industry, currently under consideration along with amendment of the Electric Utility Industry Law, can be grouped in four categories (Figure 16). They are 1) liberalization of the entry into the electricity wholesale market, 2) activation of direct supply 3) change of rating system, and 4) revision of safety regulations.

4.1 Liberalization of Entry into Electricity Wholesale Market

(1) Opening of electricity wholesale market

So far, those who hope to participate in the market as an electricity wholesaler need to obtain a “license” issued by the MITI Minister. The deregulation under examination calls for removing the licensing system and leaving the matter to the market. It is a “bidding system” that replaces conventional “licensing.” An interim report released December 1994 by a subcommittee to discuss the industry's basic problems, under the Supply and Demand Committee of the Electric Utility Industry Council, mapped out specific procedures to work out a proposed bidding system as follows.

1) Size of supply capacity subject to bidding is to be specified when power resources development plans are prepared by general electric utilities.

2) General electric utilities will prepare and publish bidding plans, which state the size subject to bidding, time to start supply, bidding conditions (avoidable cost, etc.), evaluation method, and standard agreement, and other considerations.

3) Application by bidders

4) Decision of successful bidders

5) Contract based on standard agreement

The aim of introducing this kind of bidding system is to encourage in-house power producers and cogeneration operators to participate in the electricity wholesale market. It is expected that the power resources entitled to bidding will be those which can be developed within seven years.

However, nuclear-power generation, which requires a long development period and involves great uncertainties in the future, and such large-size power resources as LNG, are not counted in that category. They remain as the power resources to be developed by general electric utilities and wholesale electric utilities power producers, with “licensing” is kept alive, as in the past. Also, the licensing system for conventional wholesale electric utilities survives intact.

(2) Free access to transmission networks

Even if barriers to new players in the electricity wholesale market are reduced by the introduction of a bidding system, the market will not necessarily be competitive. To prevent
market control by buyers, namely general electric utilities, the promotion of “wheeling” is planned as well. In other words, transmission networks owned by general electric utilities will be opened to new market players so that they can reach potential buyers in a broader area, instead of the sole one electric utility that takes charge of the area where they are located.

As for wheeling fees to be paid by the new players, applied for the present will be a corresponding fee will be applied for transfer supply (relaying) currently employed among general electric utilities. The fee is based on average transmission costs (book cost basis). It is employed on the assumption that, given that power resources of new players are smaller than those developed by electric utilities, little additional cost would be required to build up transmission facilities. Separate accounting is made if a bidder is so large as to require buildups of specific transmission facilities.

Wheeling for retailers is not counted under the wheeling issue, which is discussed in the form of opening of transmission networks.

4.2 Retailing by Non-Electric utilities

Regulatory changes under consideration widen the possibility for non-electric utilities to sell electricity directly to consumers. Conventionally “specified supply” has been treated as an exceptional form of in-house power generation. But, the drafted amendment to the Electric Utility Industry Law defines it as “specified electric utility project (SEUP),” thus positioning it as one form of electric utility.

SEUP, though in operation within a limited area, supplies electricity directly to so many and unspecified consumers that it should have high public interests. Therefore, from the standpoint of consumer protection, SEUP operators need to obtain a license similar to one currently acquired by general electric utilities. And, licensing involves “supply/demand balancing principles” similar to those applied to general electric utilities.

Also, SEUP is obliged to keep supplying to its customers within the specified area. Accordingly, the general electric utility responsible for the area where SEUP is located is exempted from the obligation to supply to the SEUP customers, though it is required to back up SEUP when necessary.

SEUP rates and supply conditions are subject, not to official approvals, but to notification alone. The grounds for the judgment are that, given SEUP customers are much more limited than those of general electric utilities, demand and cost fluctuations are likely to remain small, and the customers on their part are given, at the initial stage of contract, the right to select their supplier (a SEUP operator or a general electric utility).

4.3 Revision of Electricity Rate-Making System

The first conclusion drawn from the review on rating system-related regulations was that the total cost based method would be abided by as in the past, and that price cap system will not be introduced.
Certainly, the Rate-Making System Committee of the Electric Utility Industry Council in its interim report (Jan. 1995) conceded merits of the price cap system, citing that 1) introduction of productivity improvement rate (X factor) could prompt efforts to improve management efficiency, 2) freedom in rate-making could be augmented, and 3) regulatory procedures could be simplified.

But, the committee concluded that the introduction of the price-cap system into the Japanese electric utility industry would be problematic, especially regarding the following points. Namely, the committee asserted that 1) the price cap system would leave fears for raising necessary equipment investment funds for the security of a stable supply, 2) there is a strong social request for a cost-based equal and fair pricing system, without leaving the matter to operators' arbitrary rate-making by type of contract, 3) due to the strong nature of regional monopoly, direct price competitions among operators should not always lead to customers' advantage, and 4) a society-wide consensus could hardly be built on the productivity improvement rate (X factor) that is not yet objectively well-grounded.

Therefore, the interim report concluded that "a future rate-making system must be designed, while 1) maintaining the basic framework of the total cost-based method with which rates are set based on actual costs, and 2) introducing a mechanism (incentive regulation) of the rate-making system which could prompt electric utilities' voluntary efforts to improve efficiency, to reflect the merits of a price-cap-like simplified rules."

(2) Introduction of incentive regulation

The second feature is to adopt yardstick competition institutionally as an incentive regulation to prompt improvement of management efficiency. The following are proposed as procedures of the adoption. 1) When revising their rates, electric utilities must disclose beforehand to what extent their management efficiency is improved, and apply new rates based on the improved-efficiency-integrated cost.

2) The government examines and assesses the application with the method of (a) or (b) below, then encourages electric utilities' management efforts through resultant assessment. (a) To compare costs and management indicators of individual utilities. (b) Standard values set uniformly among individual utilities.

In Japan, similar incentive regulations have been in practice in the public transportation sector, including bus services.

(3) Fuel cost adjustment system/periodical assessment

Apart from the proposals in the preceding section, the Rate-Making System Committee of the Electric Utility Industry Council also proposed in its report to introduce 1) a fuel cost adjustment system and 2) a periodical assessment of rates.

The fuel cost adjustment system is designed to enable a prompt response to cost fluctuations resulting from fluctuations in exchange rates and crude oil prices which are
beyond corporate management efforts. The periodical assessment of rates is designed to assess rates, independent of rate revisions, and to learn the state of balance and outcome of on-going corporate efforts to improve management efficiency.

(4) Rate-making system as a demand-control option

To lower electricity rates, leveling load is an important element. To this end, it is necessary to encourage efficient use among customers by broadening the range consumer of choice in the form of more diversified/elastic rate-making.

To establish rate-making which can meet the objective, the present “approval” system will be changed into a “notification” system. The latter, once in practice, enables electric utilities to offer a diverse rates menu flexibly, and helps prepare the grounds for free consumer choice on customers side. Also, in an effort to reduce summertime peak loads, it is considering, to 1) introduce a rate-making system to alleviate the burden of cost to purchase heat-accumulator-type air-conditioners, and 2) expand application of time-of-use rating.

4.4 Safety Regulations

The request to streamline safety regulations was judged unsuitable in reference to both overseas safety regulations currently enforced and present technical levels. The Subcommittee on Electricity Safety Problems of the Supply and Demand Committee, EUIC, which has discussed rationalization of safety regulations, stressed the following viewpoints in its interim report (June 1994).

1) Importance of the principle of self-accountability and transparency of regulatory contents
2) Even after rationalized based on technical advance, safety records, etc., safety levels be maintained/improved.
3) Corporate activities be stimulated and benefits to the public be improved as a result of eased time and economic burdens.
4) Voluntary safety system be upgraded as a result of higher consciousness of safety in the private sector.
5) Rationalization be advanced in conformity with Japan’s actual situation, while referring to overseas safety regulations.
6) Safety system be constructed in a manner to meet future needs too.

Based on the examination results of the subcommittee, future safety regulations are amended in the direction below.

The most vital change in the regulations is the change in the basic stance to trim the scope of direct government involvement. In regard to electric utility facilities smaller than the prescribed size, for instance, it is proposed to 1) simplify the scope of construction plans subject to “approval“ and “notification,” 2) reduce the scope subject to inspection before
commercial operation, 3) leave periodical equipment inspection to operators’ voluntary checks, and considerably extend an interval between checks, and 4) remove the procedure to approve welding methods beforehand to be given during welding checks. However, instead of no detailed safety regulations to be offered by the government, 5) relevant authorities will be allowed to make elastic/mobile operations of on-the-spot inspections.

Along with these, an institution will be arranged to prompt voluntary safety efforts. In specific terms, there is a move to simplify the way of involvement of licensed chief electrical engineers, depending on technical levels of electrical structures (generators, etc.) Among others things, simplification of technical standards and review on categories of electrical structures is underway.

5. Effects of Deregulation

To what extent is deregulation of the electric utility industry is expected to have effects on the national economy? In order to measure the effects in terms of domestic production value, consumer’s surplus, etc., calculations were made as described below. Models in use are an inter-industry input-output table and a macroeconomic model.

5.1 Effect Estimation Method and Assumptions

Assumptions and calculation processes taken in estimating the effect are as follows (Figure 17). First, it was assumed that deregulation would help the electric utility industry improve productivity and load factor, and electricity rates would be lowered by 10% from their levels. Above all, because it is estimated that a 1% higher load factor can reduce the cost by 1%, there are high hopes for implementation of deregulation to open a road to flexible rate-making, which can promote load factor improvement.

Lower electricity rates, if realized, can reduce manufacturing costs in industries other than the electric utility industry, to bring the price of goods prices down. To what extent the price of goods of individual industries goes down can be analyzed using the inter-industry input-output table.

Effects of falling prices of goods on the national economy can be examined by dividing them into 1) price effect and 2) income effect. With price effect, a given product is priced cheaper, which results in greater demand for the product, and ultimately expands domestic production of the product. On the other hand, with income effect, falling prices of various goods increase consumers’ purchasing power in real terms, thus expanding real consumption expenditure and investment.

1) Price effect depends on price elasticity of demand for individual goods. Price elasticity of individual goods is estimated based on the input-output table. While growing domestic demand is naturally expected to expand imports, it is assumed here that the whole of incremental demand would be met by greater domestic production.
2) Income effect means an incremental income brought about by a gap between GNP resulting when electricity prices remain unchanged, and GNP resulting when general commodity prices declines thanks to lower electricity prices. Here it is calculated in terms of the domestic production value brought about by greater income.

Estimation of income effect starts by studying effects of falling prices of individual goods on the consumer price index (CPI) and wholesale price index (WPI). Subsequently, because interest rates are also affected by commodity prices, official rates are also estimated as a reaction function to commodity prices. With the CPI, WPI and the range of official rate cuts given as exogenous variables of the macro economic model, changing levels of GNP are measured. By assigning the outcome to individual final consuming sectors in the inter-industry table, an incremental portion of domestic production value can be estimated.

The effect is estimated primarily for the section of the year 2000, and by comparing the business as usual case (BAU) with a case where deregulation leads to falling electricity prices. The rate of fall in electricity prices is assumed at 10%.

5.2 Commodity prices and welfare

1) Effect on commodity price levels

A 10% fall in electricity rates leads to a 0.67% drop in manufacturing cost of non-electric industries on simple average (Figure 18). Excluding the electric utility industry, industries (goods) expected to record massive drops are iron at 1.10 and steel products at 0.71, followed by petrochemical at 0.67% and paper/pulp at 0.57%.

When measured in terms of CPI, which is weighted by goods-by-goods expenditures of private final consumption, these suggest a 0.33% fall in CPI. They lead to a 0.30% in WPI as well.

(2) Effect on domestic production value

Due to falling prices of individual goods described above, demand for individual goods grows in proportion to price elasticity. If the whole of the incremental demand is met by domestic production, GNP in the year 2000 in the lower electricity price case would be greater by ¥2.8 trillion in terms of all-industry total than in the BAU case. This represents an increase of 0.26%. With the electric utility industry excluded as the self-sector, it is processing/assembly industries, such as electrical machinery, general machinery and transport machinery that are expected to register massive gains in absolute terms. Among others, substantial increase rates are likely for material-producing industries, such as paper/pulp, cement, steel and nonferrous metals.

(3) Welfare - Consumer’s surplus

In the BAU case, the inter-industry input-output table puts nationwide electricity consumption expenditures in the year 2000 at an estimated ¥20.6 trillion (in 1985 prices).
Then, assuming that price elasticity of electricity demand is -0.45, the falling electricity price would increase nationwide welfare by ¥46 billion. The figure includes an incremental surplus recorded by firms as electricity consumers. Targeting household budget alone, electricity consumption expenditures in the household budget would total ¥4.3 trillion in 2000, which means an incremental surplus of ¥9.6 billion resulting from falling electricity prices. This represents 0.3% of electricity consumption expenditures in the household budget.

Meanwhile, measured in 1990 nominal values, an increase in nationwide welfare amounts to ¥29 billion, and that in the household budget to ¥6 billion.

5.3 Effect on Income
(1) Effect on national income
A 10% fall in electricity price pushes the CPI and WPI down by 0.33% and 0.30%, respectively. Assuming that interest rate is a reaction function to commodity price levels, taking past interrelations between the two, the elasticity is estimated at around 0.5. With the falls in these three variables incorporated in the macroeconomics model, its simulation results show that GNP in 2000 could expand by 920 billion, up 0.2% over that in BAU case. (However, because falls in the three variables are incorporated from 1996 and on, the pace of expansion would be around 0.04% a year.)

Among GNP components, it is private equipment investment that grows highest, followed by private final consumption. Compared with the BAU case, they would be larger by ¥570 billion and ¥227 billion, each, in 2000.

(2) Effect on domestic production value
Substituting relevant final demand items in the input-output table for the changes by GNP component above, domestic production would outstrip the BAU case by around ¥1.6 trillion, or up 0.18%. Industries recording massive gains are electrical machinery at ¥250 billion and construction at ¥230 billion, among others. Meanwhile, those showing high growth rates are machinery-related industries represented by general machinery, and material-producing industries like cement and steel.

5.4 Price Effect and Income Effect
When combined, the price and income effects discussed above would expand domestic production in 2000 by ¥4.4 trillion, or 0.41%, over the BAU case. By industry, machinery-related industries, such as electrical and general machinery, show massive gains in their domestic production in absolute terms. In growth terms, considerable effects are produced on material-producing industries, including nonferrous metals, paper/pulp, steel products, and chemicals and cement, in addition to the machinery industries (Figure 19).
6. Subjects of Deregulation

Given the deregulation under way, this section examines what are its effects, and what sorts of subjects still remain.

6.1 Market structure

As a result of the latest deregulation, the electric utility industry’s system is likely to change as follows.

First, participation of new players in the electricity wholesale market would help improve efficiency in the generating sector. Though it is hard to forecast to what extent new players will participate in the market, some put their generating capacity commissioned from 2000 and on at 1 GW, and others at 2 GW. Even if the capacity turns out to be limited, it would be lower than the avoidable costs of electric utilities, which is very significant in the sense that it could make marginal costs in the generating sector transparent.

In cost terms, their direct effect on overall cost reduction would be limited, because these new participants represent an extremely marginal supply capacity. But, even indirectly, their presence could stimulate cost reduction by the electric utilities.

Second, the bidding system proposed by the government indicates that the system fails to put the market to best use. If new players have highly reliable supply capacity, there is no necessity to exclude specific power resources from qualified bidders. While the bidding under the latest deregulation appears to imagine power sources for peak load as bidders, it won’t be unreasonable in the future to include base-load power sources among qualified bidders. From such a viewpoint, it will no longer be necessary to leave large-size power resources development, like nuclear and LNG, only to electric utilities alone. It could just leave to the market.

An advanced shape of such an idea is an encircling bidding system. Qualified bidders could range from a general electric utility responsible for other service areas which have surplus supply capacity, a wholesale power producer, and IPP, to the electric utility which calls for the bid itself. The change under the latest deregulation fails to take such an idea into account. But, depending on new players’ performance and external pressures, there can be mounting requests for further deregulation to realize such a drastic system.

Third, there remains the issue of how much should be charged for the use of transmission lines by new players. With the revision made this time, it was decided to charge a fee corresponding to that set for transfer supply among electric utilities. This after all assumes that supply capacity of new players won’t be so large. Once their supply capacity expands eventually, electric utilities couldn’t be so generous.

Also, in regard to charges resulting from construction of additional transmission networks, it will become necessary to put the issue into public debate, and specify it at the time of bidding.
Fourth, to further improve efficiency of opening of transmission lines/wheeling system mentioned above, relevant regulations and systems need to be changed or reviewed. The latest deregulation provides no measures to help improve efficiency of the operation of network functions of transmission lines. Therefore, even if new players are allowed to use wheeling in their wholesale electricity supply, it won’t facilitate an optimal supply/demand balance backed by transmission networks.

Any efforts to realize this should reach the use of the power pool market, as demonstrated by Britain where the transmission sector was integrated into the National Grid.

6.2 Desirable Method of Rate-making

Revised rate-making regulations enabled electric utilities to introduce elastic rate-making, which can contribute to leveling load. For consumers too, it can be highly valued for a widened possibility of choice from a diverse rating menu. Also, thanks to the introduction of incentive regulations, management efficiency can be improved more than ever. However, many subjects still remain to be pursued.

First, due to the supply cost method and FDC system being preserved intact, regulatory costs can grow. Second, there can be a distortion of resources distribution efficiency. The price-cap system, of which introduction was recently dropped, provides a viable measure to deal with these problems.

Theoretically, a cap properly set could prompt convergence to the Ramsey pricing system. Also, with a well-designed X factor of the price cap, it becomes possible to take investment into consideration from a long-range viewpoint. The price cap system can be counted as the only one rate-making system that can conform to the policy to introduce competition through deregulation.

In terms of regulatory cost-reduction, the recent changes in regulation this time could produce few favorable effects.

6.3 Problems of External Effect

Deregulation is expected to enhance efficiency by making the electricity market more competitive. To promote it further, additional changes in regulation will be required as already mentioned.

But, it should be recognized that deregulation is also accompanied by problems of external poor economy. First, there is a problem of "cream skimming". Environmental problems, and technological development are other important problems. While advancing deregulation, these problems all represent matters which require new regulations to prevent evils from arising in the form of market failure. Though not referred to in this report, it is an important subject in considering equity and fairness, as well as a stable electric utility industry's system in the long run.
Conclusion

Moves and effects of deregulation under way now in the Japanese electric utility industry have been discussed. The reasons behind the changes in the postwar electric utility industry’s system, and what effects could be produced by changing regulations, were also examined.

The discussion so far can be summarized as follows. It was widening differentials between domestic and overseas electricity prices in recent years that amounted to powerful pressures to change the regulations of the electric utility industry. But, it cannot be independent of cost increase pressures on both demand and supply sides. With their utilization technologies commercialized, new decentralized power resources have become viable as new supply sources. Collaborative study results show that the grounds for electric utilities to abide by the regional monopolistic system are thinning now, and that current rate-making system also makes resources distribution inefficient.

Under such circumstances, deregulation of the electric utility industry has been under consideration in the past few years. Expected measures of deregulation are 1) liberalization of entry into the electricity wholesale market, 2) direct supply to customers (specific utility project) 3) introduction of a more elastic rate-making system and of incentive regulations, and 4) rationalization of safety regulations. With these measures, improved efficiency of electricity supply is expected.

However, problems still remain, including introduction of enhanced competition into the generating sector, efficient operation of transmission network functions, and reexamination of the introduction of the price-cap system into rate-making.

At this time, (March 1995), the yen’s value is spiraling, making the already-wide differentials between domestic and overseas electricity prices ever wider. As a result, it appears inevitable that claims will become louder in demanding electricity price cuts and implementation of deregulation. While these short-run voices can certainly create political pressures, it is essential to consider what system can promote efficiency improvement of the electric utility industry from the long-range viewpoint.
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