replace oil- and gas-fired generating equipment are impeded by the use of AFUDC with its effect on the "quality of earnings." In addition, many utilities may not be allowed to earn a rate of return that will cover the cost of capital for new construction. These features provide strong incentives to keep existing capacity running even if newer capacity would lower costs.

Thus, regulatory practice may cause a significant increase in utility capital costs. A rough estimate of these excess costs is possible if a number of assumptions are made. The cost of capacity additions may be assumed to average $1,000 per kilowatt in 1980 dollars over the decade of the 1980s. External financing (both debt and equity) may be assumed to account for 60 percent of capital requirements, and the additional cost of external financing attributable to PUC behavior may be estimated at 1 percent on average (100 basis points). Under these assumptions, ratepayers could experience higher annual capital charges of from $800 million to $1.1 billion per year. The $800 million yearly excess cost figure is associated with a supply scenario in which only 134 gigawatts of new capacity are added over the decade. The higher $1.1 billion per annum estimate is linked to supply additions of 200 gigawatts over the decade (the base case described earlier). The interest rate (the assumed aggregate average cost of debt and equity) in the absence of adverse regulatory practice is assumed to be 12 percent for the purposes of this estimate.

CHAPTER IV. POLICY OPTIONS

Previous chapters have shown that the financial condition and regulatory treatment of the electric utility industry may ultimately lead to a serious loss of efficiency. This could come about if utilities are led to defer or avoid new capital expenditures. First, the deferral of new capacity may result in utilities consuming the wrong mix of fuels--that is, more oil and gas and less coal--than would be suggested by economic considerations alone. Second, utilities may be forced to pay more for their capital if the financial market perceives them to be less desirable investments than in the past. Finally, if new capacity additions should fail to keep pace with demand in coming years, the costs of inefficiency could become even greater as utilities are forced to meet more demand with equipment and fuels best suited to intermittent or peaking uses.

This chapter discusses the policy options available to the federal government in this area. These are generally of two types: options that would circumvent existing state regulatory practices, and options that would deliberately alter them. This division is an important one. Options that circumvent the existing regulatory treatment of the electric utility sector may be inefficient or ineffective because they preserve the existing content of utility regulation. Options that deal directly with the regulatory treatment of utilities raise the issue of states' rights in this area, since electric utility regulation is considered the legitimate province of the states. This conflict between the efficacy of the available policy options and their interference with the existing rights of states will appear throughout the discussion.

POLICY OPTIONS

Options that would not involve changes in the regulatory process include:

- Reliance on general economic recovery. Improved financial conditions, as a part of general economic recovery, may lower the cost of capital and make capacity adjustments easier. In that case, no specific policy may be necessary.

- Subsidization. Utilities could be subsidized in making capacity adjustments, particularly if they involve substituting new baseload capacity for oil and gas. This could be done either through cash subsidies or by further liberalizing the benefits from the investment tax credit and accelerated depreciation.

Another set of options would involve amending the regulatory practices of state PUCs. These can be grouped as follows:

- Imposing federal rulemaking on state public utility commissions. The federal government could determine rules regarding specific regulatory practices that states would be compelled, or induced, to adhere to.

- Regional capacity planning. Capacity planning could be done on a regional rather than local basis to achieve greater efficiency and lower requirements for reserve margins.

- Deregulating the generation of electricity. The reserved monopoly position of electric generation could be amended through a variety of means to allow free competition among bulk suppliers of electricity. Transmission and distribution would remain subject to regulation.

The discussion below evaluates each option from standpoints of efficiency and fairness. The primary criteria of efficiency are cost-effectiveness in achieving capacity adjustment, and the speed at which that adjustment occurs. The fairness criterion involves the extent to which those who benefit from a change in generating capacity (and, conversely, oil and gas displacement) are those who pay for it.

EVALUATING THE NONREGULATORY OPTIONS

Reliance on General Economic Recovery

This approach would rely on general economic recovery to improve the economic environment of electric utilities, and hence their performance. Specifically, lower interest rates and less inflation would reduce the cost of adding or replacing capacity. An economic upswing could thus be expected to increase the rate at which new baseload capacity is substituted for oil- and gas-fired units. On the other hand, it could increase the demand for electricity, thus requiring continued use of oil and gas units even with a faster rate of new construction.

The extent to which economic recovery would increase the rate at which new capacity is added would depend on the behavior of regulators.

Lower interest rates might lead PUCs to reduce the allowed rate of return afforded utilities, passing the benefits directly to consumers. Also, present regulatory practices such as fuel adjustment clauses, the predominant use of AFUDC, and historical-cost accounting might continue to inhibit utility investment regardless of the rate of interest. As noted in Chapter II, failure to address these practices appears to have limited utilities' access to capital and to have increased the cost of that capital.

A utility policy that relied entirely on improvement in the general economy would avoid the equity problems of the next option--that of subsidizing investment in electric generating capacity. It should be noted, however, that current regulatory practices themselves involve a form of subsidy. To the degree that they result in uneconomic rates of replacement for oil and gas capacity, they increase the costs of future electricity production, thus subsidizing current ratepayers at the expense of future ratepayers.

Subsidization

A subsidy in the form of federal grants or tax relief to utilities could assist them in making economic capital expenditures. The subsidy could be linked to a schedule for new capacity additions. One way to do this might be to convert the tax or cash subsidy to a government loan repayable with interest if the construction schedule was not met. Alternatively, if reconversions of coal-capable oil-fired units were not completed on schedule, recovery of oil and gas costs through the fuel adjustment clause could be prohibited after that time. The subsidy would as a rule cover only a portion of the capital costs associated with new capacity so that utilities would have to rely on the capital market, or on retained earnings, to finance the remaining portion.

Cash Subsidies. Even though a cash subsidy might be effective in hastening capacity adjustment, the unsubsidized portion of accelerated construction would still be quite substantial. Since the regulatory environment would remain unaltered, this portion might become increasingly difficult to finance. This is particularly relevant for those utilities under the greatest financial duress. The failure of this alternative to address all the financial obstacles, combined with the fact that a subsidy offers no way of reducing the risks associated with future demand uncertainty (and no way of streamlining the licensing process to shorten delays), might lead to continued shortfalls in new capacity.

Cash subsidies also fail to differentiate between electric utilities in poor financial health and those in relatively good standing. Each utility would receive a fixed percentage of the capital costs associated with new construction expenditures regardless of its financial position, providing a windfall to those in good health and not enough incentive to those in straightened circumstances. Moreover, subsidies may reward managerial inefficiency if they assist equally those utilities whose difficulties stem from poor management and those in poor financial health because of factors beyond managerial control. In addition, a cash or tax subsidy fails to differentiate between good regulatory practice and bad. To the extent that it rewards the latter, the subsidy may perpetuate the condition it is intended to remedy. A subsidy may also lead to a failure to adopt the least-cost investment alternative. For example, an oil- or gas-reliant utility might opt for the construction of a new coal-fired unit if it is subsidized, even though that may be more expensive than other options such as conservation or load management.

Subsidizing the entire electric utility industry, it can be argued, would make it unnecessary to address the particular inefficiencies of state utility regulation. But it would also shield ratepayers from the true cost of energy at a time when economic efficiency requires the use of appropriate price signals. Since ratepayers will be the prime beneficiaries of fuel switching in the generation of electricity, both efficiency and equity may dictate that they pay for this conversion. In any event, the government cannot know the economically correct rate of oil and gas replacement. To the extent that it pays too much or too little into the subsidy program, the outcome will be inefficient.

For the oil- and gas-reliant subset of the industry, there is another argument for subsidization. It can be argued that the entire nation, as well as ratepayers in oil- and gas-reliant regions, would benefit from fuel switching since it would diminish U.S. reliance on oil imports. This argument, however, overlooks the fact that it is in the interest of ratepayers to make these expenditures. The general argument for government subsidization is that intervention should occur when particular expenditures are not in the self-interest of individuals and when all citizens would benefit. Chapter III has established that reconversions to coal and accelerated construction of new coal-fired units are often in the interest of particular ratepayers and would lower the costs they pay for electricity. The fact that benefits would accrue to all citizens from a reduction in oil and gas use is not an argument for government subsidies, since these benefits would occur anyway if the regulators sought to provide electricity at the lowest life-cycle costs to their ratepayers. Finally, such a subsidization could prove expensive. If half of the 120 gigawatts of oil- and gas-fired generating capacity that cannot be converted to coal use were retired ahead of schedule, and if 10 percent of their capital costs were defrayed by federal subsidy, the cost to the federal government would be over $6 billion, assuming a cost of $1,080 in 1982 dollars per kilowatt of capacity.

Tax Subsidization. Another subsidy option would increase the electric utility industry's cash flow by further liberalizing the benefits of the investment tax credit and accelerated depreciation. The investment tax credit (ITC) allows a utility to deduct a fixed percentage of its investment expenditures from its tax liability. It therefore subsidizes capital formation. Since its inception in the Revenue Act of 1962, the ITC has been extended to electric utilities in various forms. The Revenue Act of 1978 instituted a 10 percent ITC for utilities, or 15 percent for capital expenditures associated with oil and gas displacement activities. Accelerated depreciation, on the other hand, acts as an interest-free loan that defers the taxes utilities must pay. The current asset depreciation range (the statutes that give the depreciation lives for capital equipment) was formed in 1971. Utilities could be further subsidized by shortening these ranges.

A fundamental problem with tax subsidization of electric utilities has been the limited federal tax burden borne by them. In 1979 and 1980, for example, utilities paid only $743.5 million and $1.24 billion, respectively, in federal taxes, or about one-fourth of their book tax rates. In fact, 51 (or 25 percent) of 203 private electric utilities paid no federal taxes in 1980. The Economic Recovery Tax Act of 1981 (ERTA) allowed the leasing of equipment between parties in order to transfer the attendant tax benefits, effectively creating an open market for tax benefits in excess of liabilities. This implicit "refundability" allowed tax benefits to be transferred to utilities even if they exceeded their tax liabilities. The Tax Equity and Fiscal Responsibility Act of 1982, however, limited this ability and eliminated the leasing benefits found in ERTA (although leasing may still occur under more limited rules). ERTA also allows investors preferential tax treatment of utility dividends, if those dividends are taken in the form of common stock. If dividends are taken as stock, the investor may defer taxes paid on them until the stock is sold, the proceeds then being subject to capital gains treatment (implying a lower marginal rate).

Tax subsidies carry the same general advantages and disadvantages as a cash subsidy. The advantages lie in the possibility that some oil and gas displacement activities will be accelerated through the conveyance of the subsidy. The disadvantages concern the efficiency and equity with which subsidies achieve this benefit. Subsidies reward all utilities involved in oil and gas displacement activities, even where these activities have been deferred because of regulatory practices or poor management. Moreover, subsidies do not necessarily lead to least-cost generating options. Rather, they are solely concerned with retirement or reconversion of oil- and gas-fired baseload units, and therefore may induce utilities to overlook other technical displacement activities, such as grid interconnection, conservation, or load management. Moreover, while subsidies may lead to reduced oil and gas consumption by utilities, benefiting the entire nation through lower oil imports, such reduced consumption often results in lower electricity prices to consumers. This means that ratepayers in affected regions might be subsidized for actions that would be in their own benefit even if unsubsidized.

In addition to these general considerations, there is uncertainty regarding the incidence of the benefits of tax subsidies. State regulators might opt to direct the benefits to consumers through lower electricity rates. As discussed in Chapter II, these benefits could be treated in either a "flow-through" or a "normalized" manner. Under the former, benefits are accounted for as they are incurred, and therefore the probability that they will be passed through to consumers is increased. Under normalization, the benefits are normalized over a period of time; this procedure conveys a larger portion of tax benefits to the utilities themselves. The Economic Recovery Tax Act of 1981 directed that state PUCs must use normalized accounting when treating the tax benefits associated with the provisions of that act. This treatment may make the tax benefits more effective in reducing oil and gas consumption, although most states already normalize tax subsidies. The tax leasing provisions of ERTA were curtailed in the Tax Equity and Fiscal Responsibility Act (TEFRA) of 1982. The net effect of the two on the status of leasing is not yet evident, but estimates of the cash flow benefits from the accelerated cost recovery provisions of both are possible. ERTA further liberalized accelerated depreciation for electric utilities, while TEFRA curtailed some of these benefits. Table 10 presents the projected yearly electric utility tax reduction estimates for both TEFRA and ERTA through 1986 compared to previous law. TEFRA is estimated to reduce the tax burden of electric utilities by $4.5 billion over this period, $1.2 billion less than ERTA would have. Based on the recent experience of private electric utilities, their federal tax burden may be eliminated in 1984 or 1985.

TABLE 10. ELECTRIC UTILITIES' ESTIMATED TAX REDUCTION UNDER THE ACCELERATED COST RECOVERY SYSTEM OF THE ECONOMIC RECOVERY ACT OF 1981 (ERTA) AND THE TAX EQUITY AND FISCAL RESPONSIBILITY ACT OF 1982 (TEFRA) (By calendar years, in millions of dollars)

	1982	1983	1984	1985	1986
ERTA	353	725	921	1,363	2,373
TEFRA	353	725	921	1,157	1,336

SOURCE: Donald W. Kiefer, Congressional Research Service; and the Treasury Department.

EVALUATING THE REGULATORY OPTIONS

Several policy options are available that would amend the regulatory practices of state PUCs in an effort to improve the economic performance of utilities:

- o Imposing federal requirements on state rulemaking;
- o Requiring capacity planning on a regional basis; and
- o Introducing greater competition through deregulation of generation.

All of these options would, in varying degree, preempt the traditional right of states to regulate their electric utilities. This raises a question as to whether they could be implemented without protracted legal challenges.

Imposing Federal Requirements on State Rulemaking

The first regulatory option would limit the discretion available to PUCs in regulating their utilities, substituting some federal guidance for state decisionmaking. Federal guidelines might include the following:

- o Limits to the allowed rate of return on common equity. Such a guideline would require that the allowed rate of return determined by PUCs be tied to the structure of interest rates. Alternatively, some standard of financial health could be established, allowing higher rates of return to utilities that fell outside the standard.
- o Inclusion of CWIP in the rate base. Guidelines could be formulated to require the inclusion of construction work in progress in the rate base, as opposed to the use of AFUDC accounts, as discussed in Chapter II.
- o Allowance of higher rates of return based on the performance of electric utilities. Should new capacity result in net "avoided costs," some portion of these avoided costs could be directed to utility earnings. This would give utility companies a direct financial stake in least-cost generation.
- o Amendment of fuel adjustment clauses. The use of fuel adjustment clauses could be amended to encourage fuel-switching investments.

Advantages. Imposing federal requirements in these ways would offer both advantages and disadvantages in reducing utility oil and gas consumption. Such rulemaking would directly confront the regulatory practices that have been observed to inhibit utility capital formation. Allowing higher rates of return or reducing the use of AFUDC would contribute to more investment, and also to lower capital costs as the financial community perceived less risk in utility borrowing.

These options would also assign capital stock adjustment costs to their primary beneficiaries--the ratepayers in areas now served by uneconomic generating equipment. They might also eliminate the possible tendency to subsidize future ratepayers at the expense of current ratepayers that is associated with the use of AFUDC instead of CWIP.[1]

Analysts sometimes speak of an "asymmetry of risk and reward" in utility investments.[2] That is, when new plants work as anticipated, the benefits are often shared with consumers, leaving the utility's stockholders only slightly better off. But when new units fail, the utility may be expected to cover the cost out of its profits. The Supreme Court recently

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1. An equity concern traditionally associated with the adoption of CWIP is that current ratepayers, by paying for construction work as it occurs, will be purchasing capacity that will serve future ratepayers, thereby subsidizing them. The use of AFUDC, on the other hand, is often held to shield ratepayers from power plant costs until the plant becomes "used and useful." But this shielding may not work well in practice. As the accounting earnings from AFUDC substitute for cash flow in a utility's balance sheets, investors may consider that utility's bonds less desirable. This causes them to demand a higher return on their investment, increasing the cost of capital to the utility. The higher capital charges must be borne by present as well as future ratepayers. Perhaps more important from the perspective of public policy, the use of AFUDC may cause a utility company to postpone construction that would eventually mean lower operating costs. The failure to lower costs is a burden imposed on future ratepayers by current ones. Finally, to the extent that regulation aims at reproducing the effects of the market, it is worth noting that in most of the economy future production capacity is paid for by current consumers. Thus, the argument that CWIP provides a subsidy to future ratepayers at the expense of present ratepayers is not conclusive.

2. "Balancing Risks and Rewards to Reduce Financial Disincentives to Power Plant Construction," Public Utilities Fortnightly, vol. 107, no. 4 (February 12, 1981), pp. 21-25.

refused to overturn an Ohio State Court decision that ratepayers were not liable for the costs of generating units not placed into service. Thus, utility management is not rewarded when new capacity functions without incident, but stands at risk when new capacity does not work or is deemed unnecessary upon completion. This creates an asymmetry between the risk and reward associated with building new power plants. A generic rule that would allow utilities to earn a fixed percentage of the avoided cost associated with any power plant investment would correct this asymmetry and be an inducement to further investment.

Disadvantages. The disadvantages associated with generic rulemaking are twofold. First the use of rulemaking, most likely by the Federal Energy Regulatory Commission (FERC) would effectively substitute federal for state decisionmaking. Such an intrusion would probably lead to court challenges, and would raise questions of fairness at a time when many other federal functions are being turned over to the states.

Second, generic rules may be "untargeted" in the same way that subsidies are untargeted, with the result that both utilities in financial distress and those that are financially sound would benefit from generic regulatory guidelines. This would reduce the efficiency of such rulemaking.[3]

While generic ratemaking guidelines could assist utilities in realizing higher rates of return, this addresses only one dimension of the capital disincentive problem. The other major disincentive is the ubiquitous use of fuel adjustment clauses (FACs). In the short term, FACs may lead utilities to pay too high a price for available fuel since these costs can be recouped easily. There are various ways to eliminate this bias. State PUCs could monitor fuel purchasing practices to see that the least expensive fuel of a given quality is bought. But this short-term bias is not the principal problem associated with FACs. The fuel-switching and operation and maintenance biases discussed in Chapter II result in much larger economic losses over the long term. To combat the fuel-switching bias, PUCs could employ an oil conservation adjustment clause such as that adopted in Massachusetts. This provision allows utilities to recoup capital expenditures in reconverting

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3. This does not apply to a generic rule assigning a share of avoided costs to utility earnings. The problem would be avoided under this specific rule because such "performance bonuses" would be directly tied to the provision of lower-cost electricity. This would avoid the inequities associated with providing aid to utilities that do not require it to remain solvent or attractive to investors while assisting utilities that are in a predicament because of poor management.

coal-capable oil-fired units through the fuel savings such an investment entails. Specifically, it allows utilities to retain two-thirds of the fuel savings attributable to the fuel-switching investment in a given year, while passing on the remaining one-third to consumers until the investment expenditures have been recovered. This type of clause could be extended to new coal-fired units, although the recoupment time would be much longer than that associated with reconversions. A remedy for the bias against operation and maintenance expenditures could be the inclusion of these costs in the FAC mechanism. This might lead to the opposite bias of overmaintenance, but given the very favorable payoff from additional maintenance (cited in Chapter II), the inefficiency would probably not be as great as the higher fuel costs presently experienced from undermaintenance.

Completely eliminating the FAC could be financially debilitating for the industry. Other means, such as reducing the percentage of sales covered by the clause, or increasing the recovery lags for fuel cost increases, might prove helpful in curbing these sources of inefficiency.

Requiring Capacity Planning on a Regional Basis

State regulation of electric utilities originated at a time when the scale of electrical generation was sufficiently small that all of its costs and benefits were contained within one state. Contemporary generating facilities, however, have grown to the point where the construction of new generating facilities can affect the supply alternatives of nearby states. Thus, increased interstate coordination of capacity may offer substantial economic benefits, including decreased oil and gas consumption by the affected utilities and the pooling of reserve capacity.

Regionalized capacity planning could be brought about in several ways. Those discussed here include the following:

- Ordering increased interconnections of state grids. Under current statutes, FERC has the authority to order interconnections and to order greater bulk power exchanges.

- Inducing or mandating the creation of regional regulatory bodies. State PUCs could be induced (through incentives) or required to coordinate capacity additions to neighboring states.

- Allowing out-of-state "least-cost alternatives". A state with excess generating capacity could be allowed to petition the PUCs of neighboring states for recognition as a "least-cost alternative." Utilities with excess capacity could thus assist in meeting demands in neighboring states.

Advantages. Each of these options would make lower-cost electricity available to consumers. They might also reduce utility oil and gas consumption by making better use of coal-fired capacity. Regional capacity planning would allow states to lower their reserve margins by pooling the risks of surges in peak demands, particularly when planning regions fall in different time zones or have different seasonal peak demands. Moreover, many areas with excess generating capacity fueled by coal, nuclear energy, or hydropower are adjacent to areas with slim capacity margins and significant oil- and gas-fired capacity.

An example of such complementarity can be found in the Northwest and California. The Northwest may have significant excess capacity once its remaining reactor projects are completed. It already has intermittent excess capacity from its hydroelectric system. California, on the other hand, has delayed many recent capacity additions, and has a decreasing reserve margin. Each of the three regionalization options could be applied to this situation.

Increased transmission ties between two areas could be ordered by FERC, using statutes found in current law. FERC has, under section 202(b) of the Federal Power Act, the authority to force a utility to interconnect with another utility if it finds that to be in the public interest. Section 202(h) of the same act grants FERC the authority to establish a board composed of members of the relevant PUCs to resolve the administrative problems associated with such coordination. In addition, the Public Utility Regulatory Policy Act amended the Federal Power Act so that FERC may now order the transmission of power by any utility to any requesting electric utility or federal marketing agency if it is in the public interest or if it will result in significant energy conservation, promotion of efficiency, or improved reliability of the requesting utility. However, FERC has been reluctant to require the establishment of regional regulatory bodies. Rather, it has preferred to limit its role to regulating the sale of interstate wholesale electric power and to encouraging voluntary coordination. It could, nonetheless, order such ties, or establish a regional council to coordinate the wheeling of excess Northwest electricity to California. Alternatively, the Congress could legislate the creation of such councils, or provide incentives to states to participate in them.

Disadvantages. The principal disadvantage associated with interregional links is the intrusion on the right of states to regulate electricity sales within their boundaries. Moreover, some states may not view regional coordination as being in their interest. A state with excess generating capacity might be unwilling to send power to another state, perhaps because of the environmental costs of using that capacity--even though it would reduce unit costs for consumers in both states. States with low reserve margins, the natural recipients of interstate power sales, might prefer to build their own capacity despite potentially higher costs. In the Northwest/California example, California utilities might oppose out-of-state power since it would obviate the need for more generating capacity in California and in doing so reduce the California utility's potential rate base.

The Least-Cost Option. One way of minimizing the intrusion on states' rights would be to allow out-of-state sources to petition a state PUC for recognition as a "least-cost alternative." State PUCs permit additions to capacity when utilities demonstrate that such an addition would be the least-cost method of meeting new demand, or that it would result in the retirement of units with higher generating costs. Out-of-state sources could be invited into this least-cost determination. In the Northwest/California example, utilities in the Northwest could petition the California PUC for recognition as a potential least-cost capacity addition. This would allow for regionalization of capacity planning on its economic merits, while preserving the integrity of state regulation.

Introducing Greater Competition

A third approach to the problem of utility capital stock adjustment would be to foster greater competition among generating facilities by deregulating the generation stage of electricity production. Electricity production occurs in three separable stages: electricity is generated in power plants, then transmitted to localities, where it is distributed to individual users. The regulatory process has historically considered the entire electricity industry as a natural monopoly--that is, as an industry in which unit costs continually decline as output expands, so that a monopoly will have the lowest costs. It is argued that efficiency dictates the granting of regulated regional monopolies in the generation, transmission, and distribution of electricity. But accumulated evidence suggest that declining costs are not true of the entire industry. In the transmission stage, costs decline significantly as voltage capability increases. With respect to generation, however, cost reductions associated with increases in output are not significant over a large range of firm size, and disappear long before output levels approach the size of the larger electric utilities operating today. At the distribution stage, costs are related more to customer density than to the total output of a utility. Hence, cost considerations alone do not appear to warrant the current market structure for the electric utility industry.

One response would be partial deregulation, perhaps through establishment of Regional Distribution Corporations (RDCs) which would own all of the transmission lines in a particular area.[4] The RDCs might be regulated by the Federal Energy Regulatory Commission because of the interstate business they conduct. The transmission lines would then act as common carriers for electricity, with the RDCs leasing generating capacity from independent producers. In turn, the RDCs would transmit the electricity to local distribution companies. These distribution companies could also own the generating units, but would not be able to control the transmission network. This would prevent the exercise of monopoly power that isolates small distributors from the coordinated grid shared by vertically integrated utilities. The distribution stage would still be regulated by state PUCs.

Advantages. Such a deregulation could convey several economic advantages. By fostering competition, it would give preference to least-cost generating options. It might also be a more expeditious way of displacing oil and gas than other alternatives. An RDC would create incentives to "wheel" power interregionally, taking more advantage of the power transfer opportunities associated with regional coordination. In addition, small publicly owned utilities not able to raise sufficient capital to install optimal size generating units would benefit from the lower costs of power wheeled from larger generating units. This would also displace oil and gas, since many of these publicly owned utilities are forced to utilize smaller oil- and gas-fired units because of their lower capital costs.

Disadvantages. Deregulation would pose a series of uncertainties, however, and raise new issues. One issue would be the adequacy of electricity supplies in a deregulated generating industry where generating companies would not be obligated to meet any level of demand. Regulated utilities are obligated to provide electricity to meet peak demands, and to plan adequate capacity for the long run. The costs of providing peak electricity are higher than the costs of baseload, often more than double. Since PUCs generally average in the costs of peak and baseload generation, current regulatory procedure effectively subsidizes peak uses of electricity with revenues from sales of baseload electricity. This cross-subsidization of electricity uses through the regulatory process allows the provision of peak power. Such cross-subsidization would not occur in a deregulated industry.

If peak power was not cross-subsidized in a deregulated generating industry, two possible problems might emerge. Generating firms might be unwilling to provide peak power, which would lead to brown-outs or other curtailments during peak demand periods. Or generating firms might

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4. See, for example, Matthew Cohen, "Efficiency and Competition in the Electric Power Industry," The Yale Journal, vol. 88 (June 1979), pp. 1511-49.

provide peak power but charge peak-power rates for all their sales to transmission companies. If a free market for electricity were to result in a single price for all electricity reflecting the costs of peak power generation, substantial profits would be realized by baseload power producers, and electricity prices would rise dramatically.

This pricing problem could be overcome by appropriate actions on the part of the transmission and distribution companies. Transmission companies, when buying electricity from generating stations, could be required to exercise "price discrimination"--that is, to offer higher prices only for electricity purchased during peaks. Thus, transmission and distribution companies would pay different rates for electricity provided during different times or seasons, but would charge one average price to consumers, continuing the cross-subsidization of electricity uses now common to electricity regulation. Exercising this price discrimination, however, would require new institutions to create a competitive market between generation and transmission. For example, a central dispatch office, representing the transmission grid, could receive hourly electricity "offers" from generating units that wished to supply electricity, a system now used to create a "spot market" for electricity in Florida.[5] It could then accept the lowest-cost offers that met the level of demand placed on the grid. In addition, distribution companies could be required to install "time of day" meters on all electricity users. These meters would be sensitive to the time when electricity was consumed, and would therefore allow consumers to be charged a price for electricity that reflected the costs of its generation. Such metering is technically possible, although a substantial amount of administrative effort would be required to implement it. Thus, the problem of providing peak power in a deregulated generating industry can be solved, but its solution calls for new actions on the part of the transmission and distribution system.

The long-term supply problem would be more difficult. In the face of demand uncertainty, unregulated generating companies might tend to be conservative in planning new capacity. This would transfer more of the risk associated with capacity planning to consumers. Given the long lead times required for new capacity construction, the costs associated with underinvestment in new generating capacity could be substantial. In this respect, electricity generation differs from other industries that have benefited from deregulation, such as trucking and airlines. The underinvestment problem might be solved by allowing transmission companies to buy contracts for future delivery of electricity from firms planning to build new generating

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5. The Rand Corporation, A Spot Market for Electricity: Preliminary Analysis of the Florida Energy Broker (February 1982).

capacity. This would provide early capital and assured funding to the builders of new power plants, but would still transfer more risk to consumers than they now bear. Offsetting this, electricity prices would move toward least-cost levels as competition developed.

It is also important to consider the impact of deregulation on individual firms within the utility industry. Many utilities dependent on oil and gas as generating fuels would find themselves unable to compete in a deregulated environment. Their generating units would be displaced by coal, nuclear, and hydro baseload units as transmission grids shopped for the lowest electricity prices offered by generating firms. This is the potential strength of deregulation--the displacing of oil and gas in electrical generation. Yet it would leave such utilities with unprofitable generating units, many of them with years remaining on their amortized lives. These units would have to be retired before they were paid for, inflicting economic losses on the utilities and their stockholders. Such costs might be considered unfair, since many utilities might have been prevented from retiring these units because of current regulatory practice. Such utilities would enter a deregulated environment with a competitive disadvantage, exposing them to heavy losses because of their "starting postion" in a deregulated utility industry. On the other hand, many publicly owned utilities--which enjoy significant tax and financial subsidies--would be the unintended beneficiaries of a deregulation policy. These subsidies might be reappraised in a deregulated generation industry.