Chapter 7
Policy Analysis

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A comprehensive Federal policy toward cogeneration was established in 1978. In general, the elements of this policy, which are described in detail in chapter 3, offer economic and regulatory incentives for cogeneration applications that will promote the efficient use of energy, economic, and public utility resources. The major policy initiatives include title II of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Powerplant and Industrial Fuel Use Act of 1978 (FUA), and the Energy Tax Act of 1978 (as amended by the Windfall Profits Tax Act of 1980 and the Economic Recovery Tax Act of 1981), as well as provisions of the Clean Air Act, general aspects of utility regulation, and Government support for research and development (R&D) and for demonstration projects.

It is difficult to predict what long-term effects these Federal policies will have on cogeneration. Federal ratemaking, fuel use, R&D, and environmental policies are now shifting in focus; many of the tax initiatives are too new for data on their effects to be available; and court decisions are pending on the validity of the ratemaking and interconnection provisions of PURPA. Despite these uncertainties, some aspects of Federal cogeneration policy that may discourage the implementation of cogeneration projects, or that may result in adverse impacts from such projects, have been identified and are analyzed below. These include the use of oil by cogenerators, economic incentives for cogeneration, utility ownership of cogeneration capacity, interconnection requirements for cogeneration systems, the effects of cogeneration on air quality, and the focus of R&D.

COGENERATION AND OIL SAVINGS

One of the principal objectives of Federal policy toward cogeneration is to encourage the implementation of those projects that will reduce net oil consumption, particularly by electric utilities and industry. However, despite their inherent energy efficiency, not all cogenerators will save oil. Rather, cogeneration will result in net oil savings only if an alternate-fueled cogenerator (e.g., one that burns coal, biomass, wastes), displaces **either** an electric generating plant **or** a thermal energy system that uses oil, or if an oil burning cogenerator replaces separate electric and thermal energy systems that **both** use oil and would continue to do so for most of the useful life of the cogenerator. Thus, if an oil-fired cogenerator is substituted for either an electric or thermal conversion technology that uses an alternate fuel, or that would have converted to an alternate fuel during the useful life of the cogenerator, then cogeneration actually could increase net oil consumption.

In general, Federal policies under PURPA, FUA, and the tax code are designed to discourage cogeneration applications that would not offer net oil savings over the technology's useful life. The rates for utility purchases of cogenerated electricity (and other incentives) under PURPA are only available to oil-fueled cogenerators if they meet the efficiency and operating standards established by the Federal Energy Regulatory Commission (FERC) (see ch. 3). Moreover, the PURPA incentives are more economically advantageous to cogenerators in regions where utilities depend heavily on oil-fired generating capacity. In these areas, the utilities' purchase power rates are *likely* to be based on the price of oil, and thus will be higher than the rates of utilities with primarily coal, nuclear, or hydroelectric capacity. Therefore, oil-fired cogenerators that do achieve net oil savings usually will have higher purchase power rates than those that do not. (Exceptions include States where the utility regulatory commission has set purchase power rates equal to the price of oil while the purchasing utility actually uses a mix of fuels, or has established explicit subsidy rates for purchases of cogenerated power.) Similarly, oil burning cogenerators only can obtain an exemption from the FUA prohibitions on oil and natural gas use in powerplants and industrial boilers if they can demonstrate net oil or gas savings. Finally, the energy tax credits generally are available only for energy property that uses fuels other than oil or gas.

When these policies were enacted, oil prices were escalating rapidly. It was assumed that the rising prices and uncertain availability of petroleum fuels, when combined with Federal policy, would be sufficient to ensure that only those oil-fired cogenerators that could achieve net oil savings would be worth the investment risk. However, oil prices have leveled off recently, and, although most analysts project that prices will rise slowly through the end of the decade, future prices will not be so high as projected when the National Energy Act was passed.

Thus, oil-fueled cogeneration that does not offer net oil savings may be attractive in spite of supply and policy disincentives. For example, some cogenerators may not need high purchase power rates under PURPA to be economically feasible (e.g., where retail electricity rates are exceptionally high), or may not wish to distribute electricity to the utility grid (e.g., if onsite electricity needs are large and retail rates are very high, or if reliability of electricity supply is essential). In addition, the FUA prohibitions only apply to cogenerators larger than about 10 megawatts (MW) (or a combined capacity of 25 MW per site) and those that sell more than half of their electric energy output. Furthermore, oil-fired cogenerators may be eligible for the energy tax credit if they consist of a retrofit at an existing industrial or commercial facility that results in a reduction in the amount of energy used onsite (e.g., adding a heat exchanger to an existing diesel generator). Where these special circumstances exist, oil-fired cogeneration could "slip through the cracks" in existing policies and result in increased oil use.

If net oil savings is the desired policy goal, then a number of changes in Federal policy are possible to close these gaps and further discourage oil-fired cogeneration that would not offer such savings. First, the FERC regulations implementing PURPA could be revised to include standards for fuel use in qualifying facilities (e.g., oil-fired cogenerators would not qualify for the economic and regulatory incentives offered by PURPA unless they could demonstrate a lifetime oil savings). PURPA authorized the implementation of fuel use standards, but FERC chose not to exercise its discretionary authority in this area in the belief that other provisions of the act (i. e., the efficiency and operating standards and the avoided cost rate structure) would, when combined with market forces, be sufficient to discourage oil-fired cogeneration. As stated in the introduction to the FERC rules implementing section 210 of PURPA:

> Had Congress not intended that the benefits of qualifying status be extended to oil- and natural gas-fired cogeneration facilities, the statute or [Conference Report] would have contained a restriction on fuel use similar to that which is provided for small power producers. The Congress knew that cogeneration facilities typically use natural gas and oil . . . the Congress enacted [FUA] at the same time as PURPA, [FUA] provides authority to the Secretary of Energy to restrict the use of oil and gas in cogeneration facilities. Therefore, [FERC] does not believe it necessary or appropriate to require an additional layer of fuel use regulation on technologies . . . for which another agency has authority to restrict fuel use. . . . To the extent that oil- and natural gas-fired cogeneration facilities provide for more efficient use of these resources, the Commission believes that the benefits of qualifying status should be extended to them (4).

FERC'S decision not to require cogenerators to meet fuel use requirements in order to qualify under PURPA was upheld in January 1982 by the U.S. Court of Appeals. The court agreed with FERC'S reasoning, and held that the regulations promulgated by FERC were a reasoned and adequate response to the discretionary congressional mandate.

Adding fuel use restrictions to the PURPA regulations would not necessarily block those facilities for which oil use may be economical even without the benefit of the PURPA incentives (i. e., those systems that do not need to be interconnected with the grid). To reach these cogenerators, Congress could amend FUA to prohibit the use of oil in all cogenerators, regardless of size or electricity sales, unless net oil savings are demonstrated. The guidelines for such a demonstration already are included in the Economic Regulatory Administration regulations on larger cogenerators, but extending them to cover smaller systems would require congressional action.

Finally, Congress could amend the energy tax credit (and other advantageous tax code provisions such as accelerated cost recovery) to deny credits or deductions to oil-fired cogeneration systems that cannot demonstrate net oil savings (regardless of reductions in onsite energy use).

However, each of these provisions would impose additional layers of regulation on an already complicated set of fuel use policies, and would only affect a small portion of the cogeneration market. Perhaps as little as one-third of the industrial cogeneration market potential is at sites that would install less than 25 MW. As a result, even if all the cogenerators that would be subject to these regulations demonstrated net oil savings and were installed, the resulting savings could be as low as 60,000 to 90,000 barrels of oil equivalent per day (bee/day) in 1990 (2). Moreover, the difficulty of demonstrating net oil savings and the cumbersome paperwork involved in regulations of this type could discourage even those oil burning cogenerators that would pose net savings.

One alternative to imposing additional regulation of oil use would be to tax oil consumption (e.g., an oil import fee). This would be **relatively simple to administer, and would provide an additional Federal revenue stream. Although it has been argued that such a tax would be inflationary, it also would be an effective conservation measure because it** would reach all users of oil. Therefore, larger savings could be expected than if only cogeneration were targeted.

Another alternative to additional prohibitions on oil-fired cogeneration is to amend existing Federal laws and regulations to encourage the near-term use of gas instead of oil. Natural gas supplies currently are more abundant and less expensive than oil, and over 90 percent of the natural gas used in the United States is produced domestically rather than imported. Where purchase power rates are set at or near the price of oil-fired electricity and utilities have oil or gas burning capacity, natural gas fueled cogeneration will be economically attractive even if natural gas prices approach those of distillate oil.

The use of natural gas in cogenerators also would complement the policies established under PURPA that encourage the export of cogenerated electricity to the grid as an economical alternative to building new central station powerplants, or as a form of insurance against unexpected changes in electricity demand. Currently available technologies that are likely to produce more electricity than is needed onsite (i.e., those with a high ratio of electricity-to-steam output–E/S ratio) cannot burn fuels other than oil or gas directly, and providing incentives (or removing disincentives) for the use of gas could automatically discourage oil consumption.

The near-term use of natural gas in cogeneration systems also could be an integral part of an evolutionary fuels strategy, because synthetic gaseous fuels from coal, biomass, or wastes are likely to be commercially feasible on a small or medium scale (i.e., onsite gasification systems or those with a limited distribution system) much sooner than synthetic liquid fuels. Moreover, gaseous synfuels with a low- or medium-Btu value—which can be burned in cogenerators with a high E/S ratio—are likely to be produced more cheaply from alternate fuels (e.g., coal, biomass, solid waste) than liquid synfuels. The most promising near-term liquid synthetic fuel that could be produced on a relatively small scale is methanol from wood, which also could be used in combustion turbines.

The policy options that provide incentives (or remove disincentives) for the use of gas in cogen-

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erators are similar to those described above for discouraging oil use:

- FERC could amend the PURPA regulations (without further congressional action) to deny qualifying facility status to oil-fired systems but specifically allow such status for gas burning cogenerators.
- Congress could amend FUA to extend the prohibitions to all oil-fired cogenerators regardless of size or electricity sales, while specifically exempting natural gas-fired cogenerators (or exempting those that would convert to synthetic gas or other fuels by 1990 or 1995).
- Congress could amend the energy tax credits to allow credits for gas-fired energy property but not oil-fired systems.

However, as noted above, each of these measures would prevent or discourage the implementation of those oil-fired systems that **would** pose net oil savings.

Encouraging gas-fired cogeneration in order to discourage or prevent oil burning systems is a controversial option. From a national fuels policy perspective, many analysts consider gas to be equivalent to oil in terms of its value as a premium fuel and its future supply. If onsite or modular gasification systems do not become commercial as soon as their developers project, or if the cost of synthetic low- or medium-Btu gas remains significantly higher than the cost of natural gas, then a strategy that encourages the near-term use of natural gas and a switch to synthetic gas in the long run could fail, and thus lock cogenerators into natural gas use for 10 to 20 years. Moreover, the potentially high cost of conversion to solid fuels where these fuels can be burned directly (e.g., fluidized bed), could cause cogenerators to stay on natural gas even if the solid fuel is much cheaper in the long run. Thus, making cogeneration with natural gas attractive eventually could add to supply pressures if future production and reserves are not so large as optimistic gas industry analysts project.

Large established gas users (such as electric utilities) understandably are concerned about the future uncertainty of their fuel supplies, and argue that neither oil- nor gas-fired cogenerators should be eligible for Government incentives under PURPA and the tax code. However, limiting access to, or otherwise discouraging the use of these fuels could prevent cogenerators from taking advantage of those savings that might be available. For example, a recent study that examined the effects of an additional 10 percent investment tax credit for cogeneration systems that used fuels other than oil or natural gas found that such a credit would actually **reduce** both net energy and oil savings. The reduction occurred because the additional credit would favor cogeneration technologies that use coal or other alternative fuels and thus, in the near term, would have a low E/S ratio and would not be able to displace utility oil fueled capacity (2). Therefore, measures that limit oil and gas use in cogeneration will not necessarily guarantee net oil/gas savings.

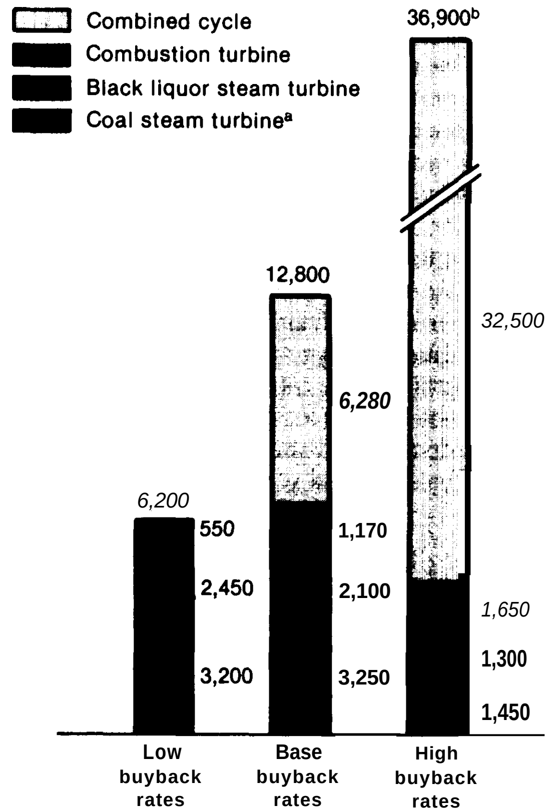
Some large established users also have argued that future supplies of high-Btu synthetic gas (the type that would be produced in large centralized facilities and distributed in pipelines) should be reserved for such users because synthetic gas with a high energy content will be supply-limited for at least 20 years. OTA did not analyze the issue of allocating such gas to a particular class of users. Rather, the gasification schemes appropriate to cogeneration would produce low- or medium-Btu gas for onsite use or limited distribution, and thus would not compete in the same markets with potential users of high-Btu synthetic gas.

ECONOMIC INCENTIVES FOR COGENERATION

Both the amount of cogeneration capacity that **will** be considered an attractive investment, and the amount of cogenerated electricity that may be available for export offsite, are extremely sensitive to economic considerations such as rates for utility purchases of cogenerated power, tax incentives, and other policy measures that reduce either the capital or operating costs of cogeneration systems. For example, a study of the potential for cogeneration development by 1990 in the five top steam-using industries under three levels of utility purchase rates found that the amount of capacity that might be installed was almost six times higher under the "high" purchase rates (ranging from 2.5cents to 7.5cents/kWh depending on the geographic region—see table 36) than under the "low" rates (1.0cents to 4.5cents/kWh). Moreover, under the higher assumed rates, a much greater proportion of the installed capacity would be high E/S ratio technologies such as combined cycles and combustion turbines that would be more likely to make electricity available to the grid (see fig. 62). Under the lower assumed rates, the amount of cogenerated steam was reduced 11 percent relative to the medium case, but the amount of cogenerated electricity was reduced by 50 percent (2). Analyses of tax provisions (e.g., investment tax credits and accelerated depreciation), and of subsidized financing (e.g., loan guarantees, low interest loans) show a similar but less substantial sensitivity of cogeneration installation and electric output to these economic incentives.

PURPA requires that purchase power rates be just and reasonable to the electric utilities' consumers and in the public interest, and that they not exceed the incremental cost to the utility of generating electricity itself or purchasing it from the grid (the "avoided cost"). FERC originally set rates for purchases of cogenerated power under PURPA equal to the utilities' incremental cost, reasoning that only 100 percent avoided cost rates would simultaneously encourage the fullest possible development of the cogeneration market and fulfill the statutory requirements for just and reasonable rates. However, the FERC rules on purchase rates were vacated by the U.S. Court of Appeals in January 1982 on the grounds that FERC had not adequately justified its choice of the "ceiling" rate established in the legislation, when a rate less than 100 percent of the avoided cost would share the economic benefits of cogeneration with the utilities' noncogenerating ratepayers (see ch, 3). The U.S. Supreme COUrt will review the appeals court decision, but final disposition of the case (either on appeal or through revised regulations, if necessary) may not occur for a year or two.

Figure 62.—Cogeneration Development Under Low, Medium, and High Utiiity Purchase Rates: 1981.90 (MW)



[a]Includes coal boilers and atmospherlc fluidized-bed boilers.
[b]The high buyback rates and amount of MW development are considered infeasible, but are shown to demonstrate the sensitivity of cogeneration development to buyback rates.

SOURCE: Resource Planning Associates, The Potential *for Cogeneration Development by 1990* (Cambridge, Mass.: Resource Planning Associates, July 1981).

Although the full avoided cost rates remain in effect pending a final decision, many potential cogenerators (except where State legislatures or regulatory commissions have instituted full avoided cost pricing independently of PURPA) have put their plans on hold as they wait to see whether, in the long term, it will be economically feasible for them to export power to the grid–and, if so, how much—or for them to cogenerate at all. Furthermore, the uncertainty about future purchase power rates has chilled the interest of potential financial backers, who may not be willing to invest in cogeneration projects without firm long-term purchase contracts with a utility until after a ruling by the Supreme Court, and—possibly–then only if the full avoided cost regulations are upheld.

Whether purchase power rates based on 100 percent of the utility's avoided cost are seen as desirable depends on the policy goal. If the goal is to maximize cogeneration's market potential, for whatever reason, then rates that reflect at least the full avoided cost are necessary (some States have instituted even higher subsidy rates to encourage cogeneration). In this case, cogeneration would bean alternative (at least in the short term) to building new central station powerplants. However, if the goal is to provide the least cost electricity supply to the ratepayer, then purchase power rates based on less than 100 percent of the avoided cost would share any economic savings from cogeneration with the utilities' other consumers.

As a compromise, the percentage of avoided cost on which purchase power rates are based could be determined regionally. In areas where utilities are heavily dependent on oil and/or are experiencing demand growth (e.g., the Northeast and Pacific Coast), rates based on 100 percent of the short-term marginal cost (usually equivalent to the cost of oil—see ch. 3) could be instituted to encourage the fullest development of cogeneration. These rates would share the benefits of cogeneration's potentially lower capital and interest costs with the ratepayers, but would not pass on any of the cost benefits attributable to cogeneration's oil savings. Alternatively, rates based on the full longrun marginal cost (equivalent to the cost of coal or nuclear capacity, or of advanced technologies) could share more of the cost savings with noncogenerating customers. In regions where the utilities' full avoided cost is very low, but cogeneration can provide insurance against sudden changes in demand, full avoided cost rates may be justified even though they would not reduce rates for other customers. But where utilities are dependent on alternate fuels and already have substantial excess capacity, cogeneration can increase rates to other consumers (through reduced fixed cost coverage–see ch. 6), and rates at less than the full avoided cost–perhaps even equal to the cogeneration cost–may be justified.

A second source of uncertainty in Federal policies that provide economic incentives for cogeneration is the continued availability of tax provisions that reduce the capital cost of cogeneration. The special tax credit for investments in alternative energy property expires at the end of 1982. A recent study of the economic incentives for cogeneration found that extending the 10 percent tax credit to 1990 (and making it applicable to oil- and natural gas-fired systems) could increase net oil savings attributable to cogeneration from 185,000 bee/day in 1990 to 210,000 bee/day. If all the fuel economically demanded by the increased investment were natural gas, the direct oil savings were estimated to increase from 280,000 to 310,000 bee/day. In addition, the amount of cogeneration capacity was projected to increase approximately 11 percent (from 12,800 MW of installed capacity to 14,400 MW) in 1990. The resulting reduction in tax receipts (discounted at a 10 percent rate) was estimated at $1.6 billion (equivalent, in this analysis, to $1.60/MMBtu, versus the saved oil cost of $5/MMBtu) (2).

The 1982 expiration of the energy tax credit will not only reduce the available investment credit by half, but also may encourage investment in cogeneration technologies "before their time." That is, advanced cogeneration technologies currently under development (including evolutionary improvements in existing technologies) will have greater fuel flexibility, higher E/S ratios, better operating efficiency, and improved environmental emissions. Many of these improvements will be ready by the mid-1980's. Thus, the continued availability of the energy tax credit would enable potential cogenerators to wait until they could select a technology that would maximize the oil savings and other benefits of cogeneration. In addition, extending the energy tax credit to 1990 would enhance cogeneration's role in an evolutionary fuels strategy, in that a potential cogenerator could invest in the basic technology now and still receive the tax credit for a later addition of fuel flexibility (e.g., a gasifier or fluidized bed combustor). Finally, availability of the energy credit after 1982 would allow innovative financing mechanisms to be developed more fully.

Similarly, the leasing provisions of the Economic Recovery Tax Act have been targeted for repeal due to the loss in Federal revenues from their widespread use by corporations seeking tax shelters. These provisions provide the primary incentive for third-party investment in technologies (e.g., cogeneration) that will contribute to energy efficiency and increased productivity, and that may be economically attractive for the user but for which the capital cost is prohibitive given the need to invest in process improvements or conservation measures. The uncertainty in their continued availability is chilling third-party investment, and thus the development of innovative private financing arrangements, because potential investors are chary of committing capital without a guarantee that the needed tax incentives will be available over the life of the investment. Additional analysis is needed to review the tradeoff between the degree to which tax leasing contributes to investments in increased energy efficiency and productivity, and its effects on Federal revenues.

Other policy measures that would provide an economic incentive for cogeneration are options for subsidized financing. High interest rates pose a substantial disincentive to debt financing, while recessionary business trends inhibit equity and internal financing. Subsidized financing options such as low interest loans or loan guarantees can reduce the problems related to the cost and availability of capital. These options could be implemented through funding for existing programs. However, Government subsidies for financing would be difficult to implement given the current Federal budget situation. The most effective way to enhance the investment climate is through policies that promote general economic recovery, and which lower interest rates by reducing inflation.

As an alternative to Government financing subsidies, private subsidies could be offered. For example, Southern California Edison offers funding assistance of up to $100,000 or 20 percent of the capital cost (excluding installation labor) of their customers' cogeneration systems. Similar programs are offered by some utilities for solar or conservation investments. The utility's investment might be included in the rate base, and the carrying costs shared by all the utility's customers. Utility involvement could encourage better integration between cogenerators and utility systems, and could increase the market potential because utilities have a broader perspective on the marginal costs of alternative energy supplies and because' subsidized financing could pose an incentive to more potential cogenerators than tax credits. However, utility financing is subject to the same potential drawbacks as utility ownership (see below), and may increase the capital cost if the utility relies on equity capital for its financing program.

UTILITY OWNERSHIP OF COGENERATORS

The economic and regulatory incentives established under PURPA are granted only to "qualifying facil it ies. ' One of the statutory requirements for qualification is that the owner of a facility not be "primarily engaged in the generation or sale of electric power" (other than electric power solely from cogeneration or small power production facilities) (3). The FERC rules implementing this requirement specify that if an electric utility, a utility holding company, or a subsidiary of either holds more than a 50 percent interest in a cogeneration facility, that facility will not qualify for the PURPA incentives. It is important to note that PURPA only limits the extent to which utility-owned systems can receive an unregulated rate of return and can price cogenerated electricity based on the cost of alternate power supplies. It does not prohibit or restrict electric utility ownership or operation of cogenerators, and where cogeneration is economically attractive relative to conventional powerplants, utilities are, in some cases, making the investment. Utility-owned cogenerators also are subject to less attractive treatment under the Energy Tax Act of 1978 because public utility property (with the exception of hydroelectric equipment) is not eligible for the energy tax credit.

The ownership rule under PURPA and the unequal tax treatment of utilities have become controversial for several reasons. Electric utilities argue that the ownership rule discriminates against them because it does not apply equally to other types of utilities (e.g., gas utilities). When combined with the tax provisions, the 50 percent ownership limitation also means that cogenerators owned by electric utilities may not be as economically competitive as facilities owned by other parties. This is especially disturbing to the electric utilities, because electricity generation is their primary business.

Furthermore, it is likely that cogeneration's market potential and electricity output would be much greater if utilities were allowed 100 percent unregulated ownership. A study of the cogeneration potential in five industries (representing 75 percent of U.S. industrial steam demand) found that, of a total technical potential of 12,800 MW by 1990, *4,000* MW would be stimulated solely by full utility ownership (2). Similarly, a study by Arkansas Power & Light (AP&L) concluded that the industrial cogeneration potential among 35 high steam load factor customers would be approximately 100 MW of electric capacity under industrial ownership, but up to 1,700 MW under utility ownership (l). The primary reasons for the differences in the amount of cogenerated electricity with utility and nonutility ownership cited by these analyses are that utilities would be more likely to choose technologies with high E/S ratios, and that utilities may require a lower rate of return and often have better access to capital markets than other investors. As a result of the higher electricity production (and thus more power available to the grid) and the better financial position, utilities could find more projects economically attractive. However, without the full PURPA benefits—especially an unregulated rate of return on cogenerated electricity—utilities would not have so much of an incentive to invest.

Finally, allowing 100 percent electric utility ownership under PURPA would lessen utility concerns about competition from cogenerators and the resulting possibility of reduced fixed cost coverage (see ch. 6). AP&L found that if the 35 likely cogeneration candidates in their service area had cogenerated in 1981 under industrial or third-party ownership, AP&L's revenue loss would have been almost $40 million in that year (1). This would mean that rates for their remaining customers would have increased as AP&L's fixed costs would be spread over a smaller number of customers while their income dropped substantially. Utility ownership would protect against such revenue losses and rate increases, and could provide additional revenue streams from steam sales while reducing the rate of increase in retail electricity rates.

As noted above, utility ownership of cogenerators is possible without changes in PURPA or the tax code. Thus, an electric utility could own regulated cogeneration capacity, or it could participate in a joint venture. In either case, some of the advantages of 100 percent unregulated utility ownership would be available, including the potential for greater amounts of installed cogeneration capacity and greater electricity output from cogenerators than under industrial or other private ownership arrangements, and protection from the adverse effects of competition. However, joint ventures may be difficult to arrange, while regulated ownership presents limited financial incentives for investments in cogeneration capacity. The regulated rate of return would, in most States, be the same for cogeneration as for other types of new powerplants (e.g., coal or nuclear) despite the potentially higher administrative costs and investment risks. Allowing utilities to compete for unregulated cogeneration capacity on the same basis as other potential investors would provide utilities with stronger incentives and ensure that the full range of benefits of utility ownership would be available. These incentives would be even greater if the tax treatment were equalized as well.

However, 100 percent utility ownership of cogenerators under PURPA also could have disadvantages. The PURPA ownership rule was enacted in part out of concern that full utility ownership might have anticompetitive effects on the development of and market for cogeneration technologies. That is, it has been suggested that utilities could "capture" the cogeneration market by favoring their own (or their subsidiaries') projects through more favorable contract terms, priority in contracting (and thus potentially higher energy and/or capacity credits), and less stringent interconnection requirements. Moreover, due to the potential for cross-subsidization, utilities' required rate of return–even if unregulated–could be sufficiently lower than other investors' and thus allow the utilities a competitive advantage. In addition, some opponents of unregulated utility ownership have argued that utilities might tend to favor a limited number of large vendors and manufacturers, with potentially adverse effects on small businesses and the development of advanced technologies.

However, the implementation of cogeneration technologies by utilities can be protected from such anticompetitive effects through carefully drafted legislation and regulations (e.g., similar to the parts of the Energy Security Act that amended the utility provisions of the National Energy Conservation Policy Act), and through traditional administrative and legal remedies. Alternatively, the question of whether utilities should be allowed to own cogenerators under PURPA could be left to the States, with requirements for case-by-case review of ownership schemes by the State regulatory commission prior to their implementation. With carefully drafted legislation and/or State review programs, it is likely that the economic and other benefits of utility ownership would outweigh the potential for anticompetitive effects.

INTERCONNECTION REQUIREMENTS

The interconnection requirements for cogeneration have become an issue for two reasons: 1) because of the procedures that may be necessary to obtain interconnection, and 2) because of the uncertainty about the amount and type of equipment that will be necessary to protect utility lineworkers and the utility system in general.

As discussed in chapter 3, the original FERC regulations implementing PURPA required utilities to interconnect with cogenerators as part of the general obligation to purchase power from and sell it to cogeneration facilities. This requirement was overturned by the U.S. Court of Appeals on the grounds that PURPA also included provisions amending the Federal Power Act to establish procedures for obtaining an interconnection order, and that PURPA did not exempt cogeneration systems from this process. Thus, absent a legislative amendment to PURPA, a cogenerator whose utility is unwilling to interconnect (or a utility who wants to interconnect with an unwilling cogenerator) must apply for a FERC order.

FERC may not issue an interconnection order under the Federal Power Act unless the commission determines that the order:

(1) is in the public interest, ***and***
(2) would (a) encourage the overall conservation of energy or capital, or (b) optimize the efficiency of use of facilities or resources, ***or (c)*** improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, ***and***
(3) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility or qualifying cogenerator affected by the order, and
(4 will not place an undue burden on an electric utility or qualifying cogenerator affected by the order, and
(5 will not unreasonably impair the reliability of any electric utility affected by the order, ***and***
(6) will not impair the ability of any electric utility affected by the order-to render adequate service to its customers.

Finally, in issuing an interconnection order, FERC must issue notice to each affected party and afford an opportunity for a full evidentiary hearing under the Administrative Procedure Act.

The requirements under the Federal Power Act will be extremely difficult and expensive for a cogenerator to meet. Even in well-understood situations, full evidentiary administrative hearings entail expenses and delays that can pose a substantial disincentive to applying for an order. But most of the showings listed above are couched in new, broad language that will have to be construed, first, by FERC and then, in all likelihood, by the courts. Moreover, in some cases, a cogenerator will not have access to the data needed to make a particular showing, or only will be able to acquire and analyze the data at great expense. Thus, these provisions of the Federal Power Act (as amended by PURPA) pose a substantial deterrent to cogenerators that cannot get an electric utility to interconnect voluntarily—one of the primary obstacles to cogeneration that PURPA was intended to remedy.

in adopting revised regulations to implement the interconnection provisions of the Federal Power Act, FERC can adopt streamlined procedures that minimize the administrative burden on the cogenerator or shift that burden to the utility; the act only specifies that the necessary determinations "shall be based upon a showing of the parties." However, full relief from the Federal Power Act procedures can only come through legislative amendment of the act to specify that interconnection is required in order to make purchases of power from, and sales of power to, cogenerators, or through independent action by each of the State legislatures.

The second area of controversy related to interconnection is the amount and type of equipment required. As discussed in chapter 4, special equipment may be necessary in order to regulate power quality, meter cogenerators' power production and consumption properly, control utility system operations, maintain system stability, and protect utility lineworkers. Given the lack of experience with power flows from cogenerators to the grid, utilities are understandably concerned about proper interconnection. But, with the possible exception of maintaining system stability, the interconnection requirements are relatively well understood, and OTA found no **technical** obstacles to proper interconnection. However, the amount and type of equipment required by the utility (or the State regulatory commission) can be a major **economic issue,** because such equipment can add substantially to the capital cost of a cogeneration system. Few guidelines for interconnection are available (other than those set by utilities), but research is underway to provide the needed information, and several groups are working on interconnection standards (including the Institute of Electrical and Electronics Engineers' Power System Relaying Committee, the Electric Power Research Institute, the Jet Propulsion Laboratory, the Department of Energy's Electrical Energy Systems Division, and the National Electrical Code). Research to date points out the need for performance-based standards that will allow cogenerators to meet functional criteria rather than requiring them to install particular types of equipment that might later be found u necessary.

Better data and additional analysis also are needed to determine the actual costs of proper interconnection. Cost estimates obtained through simulation and other techniques must be verified on actual systems. The State regulatory commissions should encourage those utilities that have not done so to prepare guidelines for interconnection, and to update those guidelines as new data are made available. However, until better data are available, it is likely that both utilities and State regulatory commissions will have to review interconnections on a case-by-case basis to ensure that both the potential hazards to the utility system and the costs to the cogenerator are minimized.

AIR QUALITY IMPACTS

Advocates of cogeneration argue that special treatment for cogeneration under the Clean Air Act would enhance its market potential, because compliance with air quality regulations is cited by many potential cogenerators as a major impediment. Suggested changes that would remove this impediment include, first, setting emissions standards that account for cogenerators' efficiency—either by tying the standards to energy output rather than fuel input or by having separate and more lenient standards for cogenerators; and second, revising new source review procedures under the prevention of significant deterioration and nonattainment area provisions of the Clean Air Act to automatically credit cogenerators for reductions in emissions from the separate thermal and electric energy systems they would replace. The costs of complying with current air quality regulations and the potential impacts of these proposed changes are discussed in detail in chapter 6 and reviewed briefly here.

Both of these policy changes would significantly reduce the costs of pollution control for cogenerators and thus would increase their economic attractiveness. However, cogeneration's fuel efficiency does not always lead to reduced emissions, nor does its substitution for two separate energy systems always produce a net air quality benefit.

In general, improved fuel efficiency will lead to reduced emissions from electricity generation only when a cogenerator replaces an electric generator of the same size and type. Thus, if the cogenerator involves new technology or fuel substitutions, or a change in scale, the net result may be an emissions increase. Even if emissions are reduced, that reduction may occur at a different location and the cogenerator could still have a negative impact on local air quality (e.g., reduced emissions at a rural powerplant but higher ambient concentrations around an urban cogenerator). Finally, cogenerators may involve a change in the type of emissions (e.g., reduced sulfur oxide emissions from a coal burning facility but increased emissions of potentially toxic diesel particulate).

Moreover, those technologies that are most likely to contribute to air quality problems–small steam and combustion turbines and diesel and spark-ignition engines—are the least likely to be controlled. At present, Federal New Source Performance Standards only apply to steam turbines larger than about 25 MW and gas turbines larger than around 10 MW. Standards for diesel nitrogen oxide emissions were proposed, but withdrawn. The emissions characteristics of unregulated technologies vary widely among different engine models, and cogeneration systems must be carefully designed, sited, and controlled to avoid adverse air quality impacts. Control technologies do exist for smaller steam and gas turbines and for diesels, but their effectiveness and costs also vary widely, and their use currently is not mandated by Federal law.

As a result of these considerations, there appears to be little public health or environmental justification for automatically granting cogenerators relief from air quality regulations. Rather, such relief might be afforded on a case-by-case basis to those cogenerators that can demonstrate air quality benefits. Moreover, the special air pollution problems posed by cogenerators that are not regulated under the Clean Air Act (either because of their size or the type of technology) may require more stringent review by State or local agencies—a task those agencies may be ill-equipped to handle.

RESEARCH AND DEVELOPMENT

Federal R&D support for energy technologies is in a state of flux and OTA was not able to analyze the direction of current research and development (R&D) efforts for cogeneration and related combustion systems. Based on OTA's assessment of cogeneration technologies and opportunities, however, it is believed that high priority should be given to funding or encouraging the development of systems with a low capital cost and a high E/S ratio that can burn fuels other than oil and natural gas cleanly. The promising applications identified in chapter 4 include the gasification of coal, biomass, or wastes for use in combustion turbines or combined cycles; fluidized bed combustion systems that can be used in conjunction with steam or combustion turbines; direct-fired combustion turbines using solid fuels (pulverized coal or wood); and advanced technologies such as fuel cells, organic Rankine bottoming cycles, and Stirling engines.

Additional R&D also is needed on the effects of a large number of dispersed generating sources on utility system stability, and for the development of low-cost effective emission controls for smaller cogeneration systems.

SUMMARY

Federal policy on cogeneration generally encourages grid-connected applications that can save oil or natural gas while promoting the efficient use of economic and electric utility resources and protecting public health and the environment. In most cases, these policies will have the intended effects. However, special circumstances may mean that some cogeneration applications could increase oil use, or have adverse economic impacts on already financially troubled electric utilities, or lead to local air quality problems. options for closing these gaps in current Federal policy initiatives are summarized in table 70. Although some of these options would require congressional action, most are relatively easy to implement (i.e., low administrative costs, few additional regulations).

Cogeneration can make an important contribution to the Nation's transition to the efficient use of fuels other than oil and gas while providing important economic benefits. But achieving the maximum benefits from cogeneration—and avoiding its potential drawbacks—will require innovation in technologies, financial markets, and utility management. And, until more experience is gained with cogeneration under the current energy, economic, and environmental context, it will require careful planning. This includes careful selection of cogeneration technologies as well as careful design and siting to ensure that the needs of both the thermal energy user and the local utility are met at an attractive cost and with minimum environmental impacts. In most cases, such planning can be achieved easily if early cooperation among all concerned parties-potential cogenerators, utilities, and Government agencies—is secured. Some utilities and State and local agencies already have initiated cooperative planning programs designed to maximize cogeneration's market potential and energy and economic benefits. Others are bound to follow as soon as they recognize that such planning is in their interests.

Table 70.—Summary of Policy Considerations Related to Cogeneration

Options	Government action required to implement options	Potential impact of options	Administrative cost
Policy Issue 1: Posslbillty that oil-fired cogeneration would increase Oil use			
A. Require oil-fired cogenerators to demonstrate net oil savings in order to qualify for PURPA benefits	Amend FERC regulations implementing PURPA	Would not block all of the oil-fired cogenerators that could increase oil use; may discourage some that would save oil	Potentially high for both FERC and oil-fired cogenerators
B. Prohibit the use of oil in all cogenerators unless net oil savings are demonstrated	Congressional action to amend FUA, plus agency implementation	Would block all cogenerators that could increase oil use; may discourage some that would save oil	Potentially low for implementing agency and high for oil-fired cogenerators
C. Deny energy tax credits for oil-fired cogenerators	Congressional action to amend tax code plus IRS implementation	Would provide further economic disincentive to oil-fired cogeneration, even when it would save oil	Low for both IRS and cogenerators
D. Encourage use of natural gas instead of oil	Same as 1A-C, but in each case specifically allowing natural gas-fired cogeneration	Would effectively block oil-fired cogeneration while providing market incentives to gas-fired; would complement existing policies that encourage conversion to alternate fuels; could lock cogenerators into natural gas use, increasing supply pressure over time	Agency costs same as 1A-C, oil-fired cogenerator costs high; gas-fired low
E. Oil tax (e.g., import tax or user fee)	Congressional action to amend tax code	Would encourage oil conservation in, all markets, provide additional Federal revenues	Relatively low
Policy issue 2 Denial of equal benefits for utiiity-owned cogenerators under PURPA and the tax code			
A. Allow 100 percent utility-owned cogenerators to qualify for PURPA benefits	Congressional action to amend PURPA plus FERC implementation	Could: increase cogeneration market penetration and electricity production; reduce rate of growth in electric rates; improve financial health of electric utilities; provide insurance against unexpected changes in demand growth. Also could have anticompetitive effects on the cogeneration market and on technology development and implementation, unless legislation were drafted carefully and/or State review programs were mandated	Low for implementation. Possibly high for monitoring potential anticompetitive effects
B. Allow energy tax credit for utility-owned cogenerators	Congressional action to amend tax code plus IRS implementation	Could stimulate utility investment with same effects as 2A	No greater than for existing energy tax credit
Policy issue 3: Tax incentive for investment in cogeneration expires in 1932			
A. Extend energy tax credit to 1990	Congressional action to amend tax code plus IRS implementation	Would provide continued stimulus to investment; allow time for advanced technologies to become commercial	Continuation of workload under present tax credit

Table 70.—Summary of Policy Considerations Related to Cogeneration—Continued

Options	Government action required to implement options	Potential impact of options	Administrative cost
Policy issue 4: Compliance with air quality regulations is a major impediment to cogeneration development			
A. Set emissions standards that account for cogenerators' greater fuel efficiency	Congressional action to amend Clean Air Act plus EPA and State implementation	Would reduce costs-of emissions control. Could result in net emissions increase, especially in urban areas	Possibly lower than under existing regulations
B. Revise new source review procedures to automatically credit cogenerators for reductions in emissions from the separate technologies they would displace	Congressional action to amend Clean Air Act plus EPA and State implementation	Would reduce costs to cogenerator of performing air quality modeling and securing offsets. Could result in net emissions increase at cogeneration site	Would shift costs previously borne by cogenerators to already understaffed State agencies
Policy issue 5: Rates for purchases of cogenerated power are uncertain			
A. Amend PURPA to set rates at 100 percent of utilities' avoided cost	Congressional action to amend PURPA	Would provide major economic incentive to cogeneration without reducing rates to other utility customers	Same as under present regulations
B. Revise FERC regulations to set rates according to regional opportunities for oil/gas and cost savings	FERC implementation	In some areas would provide less economic incentive than 5A, but would share economic benefits with ratepayers	Initially slightly higher than present regulations
Policy Issue 6: Interconnection procedures can pose substantial disincentive			
A. Redraft FERC regulations to shift evidentiary burden to utilities	FERC implementation	Would minimize procedural burden on cogenerators to obtain interconnection	Costly for FERC, cogenerators, and utilities
B. Amend Federal Power Act to require interconnection	Congressional action to amend Federal Power Act	Would eliminate procedural burden	Minimal
Policy issue 7: Interconnection requirements can substantially increase cogeneration capital costs			
A. Accelerate research and encourage utilities and State regulatory commissions to establish performance-based standards	More aggressive FERC implementation	Will reduce uncertainty for cogenerator	Minimal

SOURCE: Office of Technology Assessment.

CHAPTER 7 REFERENCES

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