Chapter 6

Impacts of Cogeneration

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ENVIRONMENTAL EFFECTS OF COGENERATION

The major environmental issue that has arisen from the promotion and deployment of cogeneration technologies concerns whether the widespread use of cogeneration may lead either to improved or degraded air quality. This issue is especially critical in urban areas, where air quality may not be in compliance with national ambient standards or where the allowable margin for additional emissions may be small. A corollary issue, also critical for urban areas, concerns the relative value of promoting cogeneration by easing environmental standards. Examples of suggested regulatory changes designed to favor cogeneration include basing emission standards on energy output rather than (currently used) fuel input, * and awarding emissions "offsets"** created by the cogenerator's substitution of cogenerated electric power for utility-generated electric power. Clearly, the issues are interconnected, because cogeneration's effect on air quality will provide a powerful argument for or against any changes in environmental standards.

This analysis of the environmental effects of cogeneration focuses on these air quality issues, with a final section devoted to other potential impacts (such as noise). First, cogeneration is characterized according to a list of attributes that affect air quality. These attributes are then discussed qualitatively and, to the extent possible, quantitatively. Next, a series of cogeneration applications are evaluated to determine their "emissions balances:" the net emissions increases or decreases in the total system (the utility grid plus local heat and electricity sources), and the net changes at the cogenerator site. Then, an evaluation of an existing air quality study of cogeneration is presented, followed by discussions of emission controls and the health effects of exposure to the major pollutants emitted by cogenerators. The air quality evaluation concludes with a discussion of the potential air quality concerns associated with advanced cogeneration technologies and an analysis of some suggested policy options for promoting cogeneration by easing environmental regulations. The chapter ends with a discussion of other potential impacts of cogeneration, including water discharges, solid waste disposal, noise, and cooling tower drift.

Characteristics of Cogeneration Systems and Their Effects on Air Quality

The deployment of cogeneration systems may involve a number of changes in the physical characteristics of electricity generation and (useful) heat or steam production. These physical changes may, in turn, alter the magnitude and dispersion characteristics of emissions from these activities. The result will be a change in air quality.

At a minimum, cogeneration will **increase fuel efficiency** by replacing separate devices producing either electricity or thermal energy with a single device providing both. Thus, less fuel would have to be burned to produce the same energy. Cogeneration may involve merely the addition of waste heat capturing equipment to existing electric generators, or the addition of turbines to existing steam producers; in this case, cogeneration **technology is different** from only one of the separate technologies. However, many cogeneration systems use technologies different from both the separate electricity generator and heat or steam producer. Cogeneration systems generally are **different in scale** from separate electricity and thermal energy systems; for virtually all applications except simple additions of waste heat recovery equipment, they are smaller in scale than the central electricity generating systems they substitute for, and in many applications they are larger in scale than the thermal energy systems. Cogeneration systems often *use*

***Because a cogenerator produces more usable energy per unit of fuel consumed than a similarly sized electric generator using the same technology, an output-based standard would allow the cogenerator to emit more pollutants per unit of fuel consumed and thus incur lower pollution control costs.**

****New sources attempting to locate in an area that has not attained Federal ambient standards must obtain pollution "offsets" (i.e., reduced emissions), from existing sources in the area so as not to increase total emissions.**

a **different fuel** from either or both systems they replace, and often they have a **different location–usually closer to the electricity demand source, at times slightly farther away from the thermal demand sources.**

Table 48 summarizes the separate impact on air quality of each of these cogeneration characteristics, assuming all other factors remain the same. For example, a reduction in fuel burned will lead to decreased emissions and improved air quality if everything else remains the same. Usually, however, lots of things have changed. For example, the substitution of several small cogenerators for a central power station may imply:

- fewer controls, because most regulations increase in stringency as size increases;
- lower stacks, which have greater impacts on ground level air quality per ***unit of emission;***
- dispersal of powerplant emissions sources–i.e., more sources with lower emissions from each separate source;
- different technology-e. g., diesels instead of fossil boilers and gas-fired furnaces;
- use of a different fuel—e.g., diesel fuel used instead of coal and natural gas.

The complex mixture of effects in this example and in table 48 implies that cogeneration **as a general concept** cannot be characterized easily as environmentally beneficial or adverse. A more detailed exploration of cogenerator characteristics is necessary in order to identify those circumstances where the environmental value of cogeneration can be defined less ambiguously.

Increase in Fuel Efficiency

As noted above, all near-term cogeneration applications involve the use of a fuel burning technology that produces **both** electricity and thermal energy, and that substitutes for a separate electric generator and thermal system. Although most applications involve a change in the scale of electricity generation (from central station to inplant generation) and many involve a basic technology change as well (e.g., steam turbines to diesels), combining the production of both electric and thermal energy in one unit creates a substantial energy savings **by itself.** For example, using a diesel cogenerator in place of a diesel electric generator and an oil-fired furnace can reduce total fuel use by at least 25 percent if three-quarters of the potentially usable heat can

Table 48.–Effect of Cogeneration Characteristics on Air Quality

Technological characteristic	Direct physical effect	Effect on air quality (positive or negative)
1. Increased efficiency	Reduction in fuel burned	Positive
2. Change in scale (usually smaller for electric generation, at times larger for heat/steam production)	Change in pollution control requirements (stringency increases with scale)	Negative for electric[a] Positive for heat
	Change in stack height and plume rise (increases with scale)	Negative for electric Positive for heat
	Changes in design, combustion control	Mixed
3. Changes in fuel combustion technology	Changes in emissions production, required controls, types of pollutants, physical exhaust parameters	Mixed
4. Change of fuels	Change in emissions production, type of pollutants	Mixed
5. Change of location (most often for electric generation)	Change in emissions density and distribution—electric power more distributed, heat/steam may become more centralized	Mixed

aThe air quallty effect of replacing the electric power component of the conventional system with the electric component of the cogeneratlon ayetem is negative.

SOURCE: Offlce of Technology Assessment.

be recovered* (11). Similar savings can be achieved by using a gas turbine cogenerator in place of a gas turbine electric generator and a separate furnace. Substitution of a steam electric cogenerator for a steam electric generator and separate low-pressure steam boiler can reduce fuel use by 15 percent (42).

Such substitutions may lead to substantial reductions in total emissions because they eliminate emissions from the heat source. For example, a diesel cogenerator could reduce sulfur oxide (SO_x) emissions by about 0.1 Ib for every 100 kilowatthours (kWh) of electricity it generated, by displacing oil heat using 0.2 percent sulfur distillate oil. Similarly, a gas turbine cogenerator could reduce nitrogen oxide (NO_x) emissions from a displaced oil-fired industrial boiler by **0.3** Ib/loo kWh (see app. B for emissions information). In some cases, however, fuel used–and thus emissions generated—by the cogenerator to produce thermal energy and electricity may be greater than for electricity generation alone, and theoretically total emissions could **increase** if the separate thermal system that is displaced were a particularly clean one. A coal or residual oil-fired steam turbine that was used for both electricity and space or process heat, for example, would add to total SO_x emissions if it replaced a similarly fueled electric generator and a separate heat system that used gas or low sulfur distillate oil.

Aside from any benefits attained by reducing emissions at the fuel combustion source, the cogenerator should be credited with environmental benefits from the remainder of the fuel cycle—i.e., the benefits of extracting, refining, and transporting less fuel. For example, reducing the use of oil for heating is most likely to reduce the impacts of importing and refining crude oil and transporting the refined product from refinery to market area. These impacts include spills of the crude and refined product and a number of pollution problems generally associated with refineries. These benefits must be balanced by any negative effects related to increased fuel transportation requirements for multiple cogeneration units.

● **The reduction is 27 percent assuming a heat rate for the diesel of 10,700 Btu/kWh, potentially recoverable heat of 4,300 Btu/kWh, furnace efficiency of 80 percent.**

Quantification of these costs and benefits is not attempted in this report, but it is important not to forget that they exist. In fact, as the more accessible fuel reserves become exhausted and extraction becomes more difficult and potentially more damaging, the magnitude of the potential benefits will grow.

Different Technology and Fuel

Although the alternative to a cogeneration system can be the identical electricity generating technology (without heat recovery) with a separate thermal energy source (boiler or furnace), often a cogeneration system replaces a completely **different** (usually large-scale centralized) electric generation technology. A common example is a cogenerator with diesel or gas turbine technology being used in place of electricity supplied by a central oil- or coal-fired steam or nuclear steam generating plant. Also, the smaller cogeneration systems typically use cleaner fuels (distillate oil or natural gas) than central station fossil plants (coal or residual oil). The technological and fuel differences both create sharp differences in emissions rates.

Table 49 displays typical levels of uncontrolled emissions from the three major competing cogeneration technologies; the steam turbine also represents the technology used in most central station powerplants. Although the same fuel is assumed, there are substantial differences in NO_x and carbon monoxide (CO) emissions, and small differences in particulate and hydrocarbon emissions. The magnitude of uncontrolled SO_x emissions is not technology-dependent because essentially 100 percent of the sulfur in the fuel is converted to SO_x regardless of the technology.

Table 49.—Uncontrolled Emissions of Competing Combustion Technologies Using the Same Fuei, in Pounds/MMBtu Fuei input
(using 0.2% sulfur distillate oil

	NO_x	Particuiates	CO	HC	SO_x
Low-speed diesei[a]. .	**3.48**	**0.07**	**0.91**	**0.10**	**0.20**
Gas turblne[b].	**0.90**		**0.02**	**0.04**	**0.20**
Steam turbine[c].	**0.16**	**0.01**	**0.04**	**0.01**	**0.20**

aBased on sales-weighted averages for large-bore dlesels, in Environmental protection Agency (39).
bBased on Environmental Protection Agency (40) and particulate emissions data from a GE 7821B combustion turbine.
cBased on Environmental Protectlon Agency (38).

SOURCE: Office of Technology Assessment.

A shift from central station electricity to diesel or gas turbine generation generally will be accompanied by a substantial increase in NO_x emissions. CO emissions also will increase significantly with diesel generation. As discussed later, however, significant differences in efficiencies and emission rates among diesels and gas turbines of different sizes, configurations, and manufacturers make it imperative that **considerable caution be used in applying "average" emission factors and efficiencies to analyses of cogeneration impacts.**

Aside from their relatively high levels of NO_x and CO emissions compared to alternative combustion technologies, diesel cogenerators face the additional problem of producing particulate emissions that appear to have a **possibility** of causing adverse health effects because of their chemical makeup. The potential effects of these particulate are discussed below in the section on health effects.

Diesel and gas turbine cogenerators must use cleaner fuels (primarily distillate oil or natural gas) than those burned in fossil-fueled powerplants (generally coal or residual oil), yielding emission benefits to the cogenerators. * Natural gas, for example, contains virtually no sulfur, and distillate oil may contain only 0.1 or 0.2 percent sulfur compared with more typical 1 percent sulfur residual oil and 1 to 5 percent sulfur coal; SO_x emissions are roughly proportional to these percentages. Although scrubbers will be used on newer utility powerplants, substantial differences among technologies in expected SO_x emissions will remain.

Fuel choice is also important for particulate and NO_x emissions, even though widely required particulate controls may eliminate some of the differences for particulate. The differences in uncontrolled industrial steam turbine NO_x emissions for coal, oil, and natural gas are displayed below:

*However, if use of these fuels were supply limited, then their use by cogenerators would have to be balanced by the withdrawal of supply from an alternative combustion source. At the moment there is no such limitation.

NO, emissions (lb/MMBtu) (38):*	
Coal (bituminous)	0.60
Oil (residual)	0.40
Gas	0.1 7

Because some large diesels (e.g., those in marine applications) use residual oil, and others are being developed that can use coal as well, some of these "clean fuel benefits" may disappear in the future as cogenerators begin to use the same types of fuels as the powerplants they displace.

Finally, fuel choice dictates the costs and benefits associated with eliminating the environmental effects of exploring for, extracting, refining and transporting the fuel used in the (displaced) conventional system, and adding these effects for the cogenerator fuel. Although many cogeneration systems use natural gas and oil, which may have fewer than or the same noncombustion environmental costs **per unit of energy** as fuels used in central station powerplants, cogeneration systems based on steam turbines may use coal and displace oil and natural gas. In these cases, cogeneration's net environmental benefit associated with the noncombustion portion of the fuel cycle may be negative even though total energy usage has decreased, because of the relatively greater adverse impacts of coal mining and transportation.

Change in Location and Scale

Even when fuel type, technology type, and efficiency are not considered, the substitution of several smaller energy producers for one or a few large producers can have substantial air quality impacts. Control requirements will vary with the size of the equipment, resulting in changes in total emissions, while the substitution of several more widely distributed, smaller smokestacks for a few large ones will change the dispersion of those emissions. Poor enforcement of control compliance for the dispersed system (due to the multiplicity of sources and the limited local en-

*Large commercial and general industrial boilers (10 to 100 MMBtu/hr), bituminous coal heat content 25 MMBtu/ton.

forcement capabilities of regulatory agencies) also may affect air quality. Of course, to the extent that the cogenerators may represent a centralization of heat production (e.g., in a total energy system for an apartment complex that replaces multiple small heating units), these effects may be reversed.

In general, control requirements for energy production technology become more stringent as size increases. Many cogenerators will be controlled less stringently than utility generators using the same combustion technologies, but controlled more strictly than small heating systems. Examples of the effect of size on control requirements for each cogenerator technology are:

New **steam generators and steam turbines** must comply with Federal New Source Performance Standards (NSPS) only if they are larger than 250 million Btu per hour (MMBtu/hr) fuel input (45). * Smaller units are subject only to local and State rules, some of which may not be so stringent. Furthermore, generators larger than this cutoff are subject to different emission limits depending on whether or not they are utility-operated. New utility-operated steam generators must achieve 90 percent SO_x control for oil and for medium to high sulfur coal, and **70** percent for low sulfur coal, with an upper limit of 1.2 lb/MMBtu input. In addition, they are restricted to 0.03 lb of particulate per million Btu input. in contrast, new large steam generators used as industrial cogenerators need achieve only 1.2 lb of SO_x per million Btu input and 0.10 lb of particulate per million Btu input.

New **gas turbines** with fuel rates greater than about 100 MMBtu/hr must achieve 75 ppm NO_x (about 70-percent reduction from uncontrolled levels) under Federal NSPS, whereas turbines in the 10 to 100 MMBtu/hr range need reach only 1 **so** ppm (40-percent reduction) (46). The iatter standard does not go into effect until about 1983. Gas turbines smaller than 10 MMBtu/hr are subject only to State and local regulations (if any), although gas turbines in this size range currently do not appear to be a likely technological choice for cogeneration applications.

Thus, it appears that new gas turbine cogenerators will have either emission standards equal to those of large utility gas turbines or, for the smaller units, half as stringent. Future improvements in the efficiency and economics of very small gas turbines conceivably might lead, however, to turbine cogenerators below the NSPS cutoff and thus only subject to local emission standards.

Stationary diesels currently are not regulated at the Federal level. The Environmental Protection Agency (EPA) has proposed new source performance standards for stationary diesels above 560 cubic inch displacement per cylinder, which essentially includes most low- and medium-speed diesels (less than 1,000 rpm) (39). In the absence of the NSPS, it appears likely that most cogenerators would fall in this size range. However, it is unclear whether the incentive of potential escape from controls might lead, upon the promulgation of a Federal emission standard, to deployment of smaller displacement diesel cogenerators. In fact, incentives to purchase such smaller displacement diesels may precede a Federal standard; at least one EPA regional office is reported to be requiring control to the proposed NSPS level even without the benefit of a formal standard (8).

Small cogenerators could escape the effect of additional emission limitations (beyond the Federal NSPS) in nonattainment and prevention of significant deterioration (PSD) areas (see ch. 3). These limitations are triggered by annual emissions of either 100 tons per year (tpy) (steam turbine) or 250 tpy (diesel and gas turbine) of any criteria* pollutant (44). For example, a 1-MW diesel achieving the proposed NSPS NO_x level (600 ppm or **about 2.20 lb/MMBtu) (2,39) would emit a maximum of 96 tpy of NO_x even if it ran continuously at full load. Thus, it could avoid the nonattainment or** PSD requirements, whereas a large utility plant could not.

Table 50 indicates the size limit necessary to avoid a nonattainment or PSD review (i.e., to emit

*Equivalent to about 200,000 lb of steam per hour or 25 MW of electrical capacity.

*A "criteria" pollutant is one that is regulated under the Clean Air Act by a National Ambient Air Quality Standard. Current criteria pollutants are sulfur oxides, particulate matter, nitrogen dioxide, hydrocarbons, photochemical oxidants, carbon monoxide, and lead.

Table W.—Maximum Size Cogenerator Not Requiring New Source Review

Technoloav	Megawatts	
Dlesels	300/0 efficient	
NO, limit:		
Oil-fired uncontrolled . .	1.5	
Dual-fuel uncontrolled .	2.2	
Proposed NSPS	2.5	
Gas *turbines*	*30°A* efficient	200/0 efficient
NO_x limit, assuming NSPS	17.0	11.5
SO_x limit:		
1.O% sulfur oil	5.0	7.5
0.30% sulfur oil	16.5	10.8
0.20% sulfur oil	24.8	16.3
Steam turbines	150/0 efficient	100/0 efficient
NO_x limit:		
Coal-fired	7.9	5.6
Oil-fired	3.4	2.4
Gas-fired	2.2	1.6
SO_x limit:		
0.2% sulfur oil	5.0	3.3
1.0% sulfur oil	1.0	0.7

[a]Plant electrical efficiency, Btu (electrlcity) 100/Btu (Input fuei).

SOURCE: Office of Technology Assessment.

less than 100 or **250** tpy of a criteria pollutant) for a cogenerator operating at 100 percent load. Under existing regulations, cogenerators larger than this size also could avoid review by applying sufficient controls to reduce their emissions to just below the limit.

The change in scale and location associated with cogeneration replacing conventional energy systems can have a substantial effect on the dispersion characteristics of the emissions. In some circumstances, this change in dispersion will influence ambient air quality more strongly than the changes in the amount of emissions. The air quality changes, however, will depend on a variety of factors including meteorological conditions, effective stack heights, terrain, and location of the emissions sources. This large number of physical factors, coupled with a wide range of technology choices, makes air quality modeling of an appropriate range of cogeneration and conventional systems expensive, and it was not attempted. However, by relying on existing studies and diffusion theory, some of the qualitative differences between alternative electric and thermal energy production systems can be described.

Although both a cogeneration-based system and a conventional system consist of combinations of centralized and dispersed sources (the cogeneration system usually requires central station backup), a good part of the air quality differences between the two systems can be understood by comparing the pollution effects of centralized emission sources with tall stacks to the effects of multiple dispersed sources with shorter stacks. This is because cogeneration installations often are added to a large existing (conventional) system (i.e., a utility grid and a series of localized heat sources) and in many cases simultaneously increase the emissions from dispersed sources* and decrease the centralized emissions. The air quality tradeoff between dispersed and centralized sources thus is an important determinant of whether adding cogeneration is environmentally preferable to maintaining the conventional system.

The air quality tradeoff between central and dispersed sources–between a few sources with tall smokestacks and multiple sources with relatively short stacks—is difficult to evaluate because the tradeoff changes with local conditions. Some of the general features of the tradeoff can be described, however, by looking at a simplified example and then showing the effects of varying conditions, one at a time.

The simplified example considers a very large area with a relatively flat terrain. The centralized system is represented by a few large emission sources with tall stacks—on the order of several hundred feet in height. The dispersed system is represented by many smaller sources with short stacks scattered relatively uniformly throughout the area. The total emissions from each system are assumed to be equal.

As long as the area in question is very large and the air quality is averaged over a long period—a year, for example–striking differences in air quality between the two systems usually will not be seen. * The few tall stacks achieve a relatively uniform dispersion of pollution because of their superior diffusion characteristics; the more numerous shorter stacks achieve a somewhat sim-

● There are important exceptions to this, e.g., when the heat source that is substituted for is more polluting than the cogenerator, or when the cogenerator is replacing multiple small heat sources.

*in some situations, when there are strong differences in the prevailing winds at the different heights, strong differences may occur.

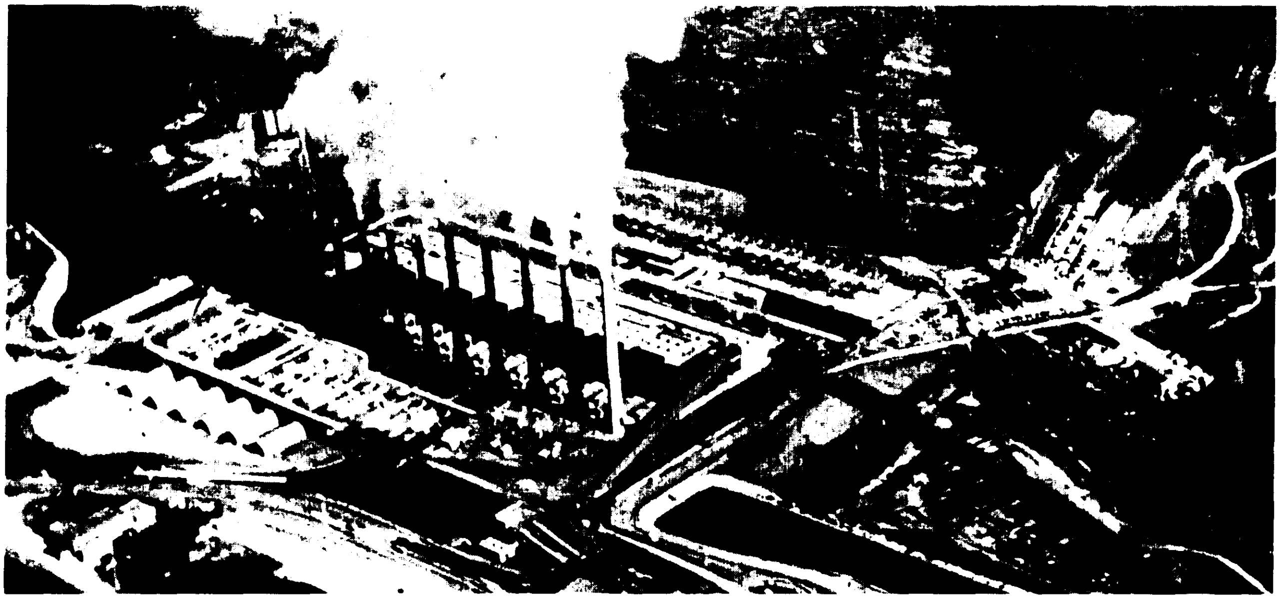

Photo credit: Environmental Protection Agency

Photo credit Department of Housing and Urban Development

The substitution of multiple small cogenerators in urban areas in place of centrally located powerplants involves shifts in location, stack height, magnitude, and type of air emissions and can have significant impacts on air quality

ilar effect (albeit with many small peaks and valleys in pollutant concentration levels) because they are spread out.

The actual characteristics of the choice facing a decision maker usually are quite different from this idealized case. Often, the short stacks—the cogenerators—are clustered within a relatively small area rather than being widely scattered. Short-term meteorological conditions may disrupt the smooth dispersion of pollutants from tall and short stacks in drastically different ways. When the cogenerators are located in urban areas, their proximity to other buildings may affect emissions dispersion. And sometimes the tall stacks–the central power stations—are located in a different area from the cogenerators. Each of these conditions affects air quality and must be considered in examining the tradeoff between cogenerators and conventional central utility systems.

Clustering of the small sources within an urban area makes the dispersion characteristics of a tall stack in the same area superior to those of the small stacks. This is because the effective area of dispersion of a tall stack is very large, whereas the clustering of small sources has defeated their potential for geographically based dispersion. Thus, a series of emission sources with relatively short stacks—such as cogenerators—located in a relatively small area will have a considerably greater impact on local (average annual) air quality than a single source with a tall stack located in the same area.

However, if the tall stack is located some distance from the cluster of short stacks, the air quality of areas at a distance from the cluster of small sources may show some improvement as a result of reducing emissions from the tall stack. In situations where the problems associated with long-distance transport of air pollution (e.g., acid rain) are considered to be more important than existing local air pollution problems, a switch to short stacks may be viewed as beneficial to overall air quality.

Short-term meteorological conditions may substantially change dispersion characteristics and alter the air quality tradeoffs between short and tall stacks. Under inversion conditions, when high levels of pollutant concentrations can result from sources under the inversion layer, the buoyant plume from a tall stack may be able to punch through the inversion layer and, consequently, have minimal impact on local air quality. Emissions from lower stacks, on the other hand, are trapped beneath the layer and are poorly dispersed. During other conditions, plumes from either tall or short stacks may be forced to ground level ("fumigation"). Under fumigating conditions, the concentration peaks from the few large sources with tall stacks can be considerably larger than the concentrations possible with a series of dispersed, smaller sources with low stacks. Fumigation conditions include the breakup of a night-time inversion, certain kinds of shoreline wind conditions, and thermal instability causing looping plumes. Mountainous terrain can also cause powerplant plumes to touch down. Other conditions, such as the trapping of emissions beneath elevated inversions, may also diminish the dispersion advantages of tall stacks.

Careful siting of cogenerators can be critical in urban situations because the unique terrain conditions can adversely affect dispersion of emissions. Plumes from cogenerator stacks may be caught in aerodynamic downwashes caused by the action of wind around neighboring buildings (or, in some cases, around the stack itself) and cause high pollutant concentrations in the immediate area of the stack. In addition, the plume may impinge on surrounding buildings, especially if they are taller than the stack or fairly close to it.

Pollutant concentrations caused by this "urban meteorology" may be much higher—perhaps by an order of magnitude or more—than predicted by models assuming unobstructed dispersion. For example, a calculation of the effect of downwash caused by airflow around a small building housing a diesel cogenerator showed an increase in maximum ground level concentrations of NO_x from 400 micrograms per cubic meter (ug/m3) (no downwash, 10 m stack) to 6,000 ug/m3 (downwash) (5). Concentrations may be still higher on the faces and roofs of surrounding buildings. Because roof areas may be used as recreation areas or for fresh-air intake, and building faces may have open windows, downwash problems must be taken extremely seriously.

Aerodynamic problems from the cogenerator's building or from surrounding buildings of similar height can be eliminated by the simple expedient of increasing the stack height. Unless surrounding buildings are close and their height is considerably taller than the stack, the stack height levels needed either to avoid any effects or to avoid the worst downwash effects usually are not so high as to render the system infeasible. For example, for a 7 m high building with no problems from surrounding buildings, stack heights that avoid all building interaction effects are on the order of 10 to 14 m above the roofline if the building is of moderate horizontal dimensions. A 6 m stack might be tall enough to avoid the worst downwash effects (5). The presence of nearby buildings of similar height adds to the downwash problem, but the additional stack height necessary to avoid problems is not great; for 9 m high buildings, only 3 m would have to be added to the stack (5). If the surrounding buildings are much taller than the cogenerator's building and closer than about three times their height, however, then the cogenerator can only free itself of their adverse aerodynamic influence by raising its stack above their height (5). The economic and esthetic effects of this requirement will be quite high in some cases.

Finally, in cases where an area's electricity is imported from distant powerplants, the tradeoff between short stack cogenerators and central powerplants with tall stacks is complicated: the emissions from each alternative affect different areas that may have different meteorological conditions, background air quality, and other factors that determine pollution impacts. Also, because a utility often can choose among a variety of supply alternatives, including different types of powerplants within its airshed (possibly using different fuels or maintaining different levels of pollution control) and long-distance power imports, the air quality tradeoff becomes still more complex and is difficult to evaluate properly.

One factor in this tradeoff is fairly consistent, however. New powerplants generally are located far from densely populated urban areas, whereas cogenerators serving urban areas are located there. Thus, peak pollutant concentrations caused by short-term unfavorable meteorological conditions generally fall outside of the urban areas for powerplants and inside these areas for cogenerators. Consequently, the actual population exposure due to the cogenerators may be higher than the exposure caused by the powerplant even during conditions when the cogenerator-related concentrations are much lower than the concentrations associated with the powerplant. These differences may have important implications for the health effects of alternative centralized and decentralized systems, although there are other effects (such as ecological damage) for which the above differences are either unimportant or imply higher costs from the powerplants.

Emissions Balances: Cogeneration v. Separate Heat and Electricity

Computing the air quality effects of any technological change is always made difficult by the complexity, expense, and inaccuracy of air quality modeling. In the case of cogeneration, this computation is further complicated by difficulties in determining the emissions changes occurring in the central utility system and by substantial variability in the emissions factors to be applied to the cogenerators.

The response of the utility system to an increase in cogenerated power—a critical parameter in determining not only emissions impact but also oil savings (or loss)—is difficult to predict. The addition of significant levels of cogenerated power to a utility's service area will affect both its current operations and future expansion. If the cogenerated power represents a displacement of current electricity demand in the service area (i.e., with retrofit of an existing facility for cogeneration), the utility will either reduce its own electricity production or reduce power imports, with its decision based on costs, contractual obligations or, perhaps, politics. It may also move up the retirement date for an older powerplant or cancel planned capacity additions in response to cogenerators' displacement of either current or anticipated future demand. Because most uti{ity grids draw on a mix of nuclear-, coal-, and oil-fired steam electric generators for base and intermediate loads, and oil- or natural gas-fired turbines for peaking capacity (as well as hydroelectric and natural gas-fired steam electric plants in some parts of the country); because these plants may be scattered over a wide area; and because control systems for the fossil plants may vary drastically in effectiveness, the pollution implications of the response of the utility system to cogeneration are highly variable.

Aside from problems in computing the utility system impacts, a variety of factors create analytical difficulties in calculating the emissions likely to be produced by a cogenerator. For example, the potential variability in organic nitrogen and sulfur content of future fuel supplies for gas and steam turbines and diesels may have substantial impacts on the level of NO_x and SO_x emissions unless appropriate controls are applied to compensate for fuel quality. Differences in the specific design and duty cycle of cogenerators also may create substantial variability in emissions from engines of the same size and technology. CO and unburned hydrocarbon emissions from diesels depend on injection pressure (range: several hundred to 20,000 psi, though not for the same size engine), engine speeds, use of a precombustion chamber, and other factors. NO_x emissions depend on combustion and postcombustion temperatures, which can vary substantially in diesels and gas turbines. Emissions of all three of the above pollutants depend on load, which can vary from application to application. Data from EPA and other sources show that uncontrolled diesel hydrocarbon emissions can va~ by a factor of 29 (0.1 to 2.9 grams/horsepower/hour (g/hph)), CO emissions by a factor of 49 (0.3 to 14.6 g/hph), and NO_x emissions by a factor of eight (2.1 to 17.1 g/hph) (39). Although controls required by uniform emission standards should reduce this variability, it is likely that even controlled emission rates will vary substantially from one installation to another, because controls are unlikely to be "fine-tuned" to account for variations in fuels and operating procedures, and because different manufacturers will choose different margins of safety and control techniques to ensure compliance.

OTA calculated the emissions impact–both at the cogenerator site and over a larger area encompassing the cogenerator site and the entire utility grid—for a variety of situations where a cogenerator replaces or substitutes for a more conventional electricity and heat supply option (e.g., central station power plus onsite boiler). The results are shown in table 51. The substantial number of combinations of: 1) **cogenerator type and fuel, 2) central power station type and fuel,** and 3) **local heating type and fuel** that are analyzed, and the normalization of the calculations to 100 kWh of electricity generation are designed to compensate in part for the site-specific variability of cogeneration installations discussed above. Emissions data for each of the separate modules are given in appendix B, and these data may be readily used to compute additional combinations. Unfortunately, the variability in emissions factors caused by design and operating variations is not accounted for in table 51.

A key conclusion that can be drawn from table 51 is that substituting cogeneration for more conventional systems will not result in automatic pollution gains or losses despite the increased efficiency. If the variability not accounted for in the table is further considered (e.g., alternative fuel compositions, or the considerable range of emissions factors possible within a cogenerator technology type), the potential for achieving a wide range of positive and negative emissions effects by varying the precise cogeneration system design becomes even more readily apparent.

Diesel cogeneration may be an important exception to this conclusion. Diesel cogenerators will tend to cause a strong increase in NO_x both at the cogeneration site and in the overall regional balance (utility plant reduction included), mainly because diesels are very high emitters of NO_x. Although CO emissions increase by about the same order of magnitude as NO_x, the CO increases are far less significant because the toxic effects of NO_x occur at concentrations that are at least 10 times lower than the levels at which CO becomes toxic.

The actual effect of diesel cogenerators on emissions and air quality will depend on the degree of attention paid to environmental control. If minimum NO_x emissions were judged to be of critical importance in a series of cogeneration installations in an area, appropriate selection

Table 51.—Selected Emissions Balances for Cogeneration Displacing Centrai Power Pius Locai Heat Sources[e] (normalized to 100 kWh)

			Net emissions (lb)					Net emissions at cogeneratlon site (lb)				
Cogenerator Replaces	Central power Plus	Heat	NO_x	Partlculates	CO	HC	SO_x	NO_x	Partlculates	CO	HC	SO_x
Diesel (011)	New coal plant	Domestic gas	+2.84	+0.04	+0.65	+0.09	–1.12	+3.39	+0.07	+0.90	+0.10	+0.20
	Older oil-fired plant	Domestic oil	+2.69	–0.01	+0.88	+0.08	–0.93	+3.37	+0.06	+0.89	+0.10	+0.12
	Existing gas turbine (oil) peaking unit	Domestic 0il	+2.36	+0.02	+0.77	+0.06	+0.09	+3.37	+0.06	+0.89	+0.10	+0.12
Note: Proposed diesel NSPS subtracts 1.2 lb NOx/100 kllowatthours												
Diesel (90 percent gas, 10 percent oil)	Any combinations		Slgnlflcant changes from above: 1) 0.77 lb/100 kWh more HC 2) 0.94 lb/1OO kWh leas NO_x									
Gas turbine (NSPS) (gas)	Older coal-fired plant	Domestic oil	–0.39	–0.29	+0.09	+0.03	–4.52	+0.30	+0.02	+0.13	+0.04	–0.14
		011-fired Industrial boiler	–0.80	–0.40	+0.09	+0.03	–5.17	+0.09	–0.09	+0.13	+0.04	–0.79
	Older oil-fired plant	Coal-fired Industrial boiler	–0.84	–0.40	+0.05	+0.01	-3.27	-0.04	-0.35	+0.09	+0.02	–2.18
	New coal plant	Gas-fired Industrial boiler	–0.28	–0.01	+0.10	+0.04	–1.31	+0.27	+0.02	+0.14	+0.05	+0.01
Note: Removing gas turbine NSPS adds 0.4 lb NOx/lOO kilowatthours												
Gas turbine (NSPS) (oil)	Older oil-fired plant	Oil-fired Industrlal boiler	–0.61	–0.09	–0.03	+0.03	–1.65	+0.09	–0.04	+0.01	+0.04	–0.60
	Older natural gas-fired plant	Gas-fired Industrial boiler	–0.40	+0.06	o	+0.01	+0.20	+0.27	+0.07	+0.02	+0.05	+0.20
Note: removing gas turbine NSPS adds 0.8 lb NOx/100 kllowatthours												
Steam turbine, coal fired	Older oll-flred plant	NSPS steam boiler, coal	–0.38	–0.01	–0.02	o	–0.49	+0.32	+0.04	+0.02	+0.01	+0.56
	Older natural gas-fired plant	NSPS steam boiler, coal	–0.35	+0.03	o	–0.03	+0.56	+0.32	+0.04	+0.02	+0.01	+0.56
	Nuclear plant	NSPS steam boiler, coal	+0.32	+0.04	+0.02	+0.01	+0.56	+0.32	+0.04	+0.02	+0.01	+0.56
	Older oil-fired plant	Oil-fired Industrial boiler	+0.38	–0.13	o	0	-0.11	+1.08	-0.06	+0.04	+0.01	+0.94
		Older oll-fired boiler[c]	–0.37	+0.12	–0.02	–0.01	–0.12	+0.33	+0.17	+0.02	o	+0.94

aSee app. A for assumptions on controls and emlsslons rates.
b This might represent replaclng a number of oil-fired process heat boilers In an Industrial park with a single coal-fired cogenerator.
cEssentially ldentical in (emissions per million Btu) with the older Oil-fired PowerPlant.

SOURCE: Office of Technology Assessment.

of diesel designs and use of controls could lower emissions from the level shown in table 51.

Gas turbine cogenerators do not appear to cause consistently strong changes in emissions either locally or regionally, except for: 1) regional SO_x reductions due to turbines' clean fuel requirements, 2) regional NO_x reductions resulting from the increased efficiency of the cogeneration systems, and 3) small NO_x increases locally. The regional NO_x reductions would be largely lost and local increases made larger by 0.4 to 0.8 lb/100 kWh if NO_x controls were no longer required.

Finally, coal-fired steam turbine cogenerators are likely to create mild increases in NO_x and somewhat larger increases in SO_x emissions locally because of the increased fuel consumption at the site. Regional effects are mixed.

An Air Quality Analysis of Urban Diesel Cogeneration

To our knowledge, there have been few analyses of the air quality effects of an areawide installation of cogeneration equipment, and only one non hypothetical area—New York City—has been modeled explicitly. Both Consolidated Edison (ConEd), the utility serving New York City, and the New York State Public Service Commission staff have conducted dispersion modeling studies to evaluate the impacts of installing multiple cogenerators with a combined electric capacity of as much as 1,000 MW* (14,19,21). The results of these studies, which generally show

● The Con Ed analysis is reported in detail in Environmental Research and Technology, Inc. (19), and updated and revised in Freudenthal (21). The Public Service Commission analysis is described in Domaracki and Sistla (14).

adverse effects on air quality, have been widely disseminated by ConEd, which is opposed to urban cogeneration, and they have become controversial. Consequently, they deserve closer examination.

The most recent study by Con Ed examines the impact of installing 141 cogenerators in Manhattan, displacing 514 MW of ConEd's capacity as well as a considerable amount of space heating. In this study, annual nitrogen dioxide ($N0_2$) concentrations in a large part of Manhattan were predicted to increase by more than 14 pg/ms, with a resulting violation of Federal ambient standards in this area (21). This most recent version of ConEd's analysis corrects two major problems affecting the results of an earlier study examining the impacts of 1,086 MW of cogeneration capacity: collocation of multiple emission sources and location of receptors too close to emission sources (19).

However, evaluation of the most recent ConEd analysis should take into account the following considerations:

1. The analysis assumes an emission rate of 17.3 g/kWh of NO_x for the diesels. This appears to be a reasonable value for uncontrolled oil-fired diesels, but it is substantially higher than the approximately 10 g/kWh proposed for the Federal NSPS. Furthermore, diesels that do considerably better than the assumed uncontrolled rate are available, so that careful selection of manufacturers and models could yield significantly lower emissions even without adding controls. Consequently, the assumed emission rate is valid only if selection of diesels is made with no concern about their emission rate and if manufacturers of diesels make no attempts to reduce emission rates in the next few years.
2. The analysis examines only one distribution of sources and does not attempt to find a more acceptable pattern (e.g., by removing a few critical cogenerators). This implicitly assumes that air quality considerations will play no role **in the siting of cogenerators, and thus that permitting procedures are ineffective. This implicit assumption** has been challenged by the State Department of Public Service (DPS) (14). DPS notes that most cogenerators will undergo PSD reviews, and also that proliferation of cogeneration will result in an appropriate regulatory response on the part of the State. DPS believes that the present inadequacy of regulations for cogenerator siting is the result of the lack of development activity. However, there is no guarantee that local reviews, currently considered by some to be inadequate, will be sufficiently upgraded in response to a surge in cogeneration activity. In the testimony cited above, the witnesses agreed that none of the cogeneration sources included in the Con Ed analysis would have been prohibited under existing regulations,
3. ConEd has assumed that commercial cogenerators will be able to use only 50 percent of their recoverable heat (thermal efficiency of 52 percent), and residential cogenerators will use 75 percent of their recoverable heat (62 percent thermal efficiency). Available studies of cogeneration assume significantly higher thermal efficiencies, which in turn would change the emissions balance of cogenerator, central power station, and furnace or boiler in favor of the cogenerator. As discussed in chapter 5, ConEd's assumptions imply no thermal storage and "electrical dispatch"—running the cogenerator only when sufficient electrical demand exists. With the Public Utility Regulatory Policies Act of 1978 (PURPA), cogenerators are more likely to operate on "thermal dispatch" and distribute any excess electricity to the grid. Consequently, their overall efficiencies should be higher than what Con Ed assumes, with more favorable emissions balances.

Despite the inherent inaccuracy of diffusion models, especially in urban applications, it seems prudent to consider the prediction of a general increase in NO_x concentrations to be roughly accurate **for the particular situation examined.** The potential problems in ConEd's analysis with the cogenerator thermal efficiencies should not drastically affect this prediction. The remaining problems with the analysis, however, demand a very careful interpretation: **OTA interprets the Con-Ed analysis as showing that any additional development—including multiple installations of diesel cogenerators—that could produce an increase in local urban emissions, might create air quality problems if adequate controls were not required and if permits were issued without careful consideration of stack height, siting, and other parameters affecting pollutant dispersion.** In areas where existing air quality is not substantially better than the Federal ambient standards, it appears likely that some permits may have to be denied to avoid violations of these standards.

Emission Controls

Potential air quality problems like the ones described above can be ameliorated if emissions can be controlled sufficiently. As noted previously, however, controls will not automatically be required by law in many situations, especially for small cogenerators such as diesels and spark-ignition engines that are not covered by Federal NSPS and may not be subject to State and local regulation. For technologies to which NSPS **do** apply (e.g., gas turbines) the required level of control may not be as stringent as the local air quality situation might call for, because most State and local environmental authorities are reluctant to go beyond the NSPS requirements. This section describes the available controls for NO_x emissions from reciprocating internal combustion engines and gas turbines. Emissions from industrial boilers (for steam turbine cogenerators) are not discussed, but EPA is preparing an NSPS background document for these emissions sources. *

Reciprocating Internal Combustion Engines

In 1979, EPA proposed an NSPS of 600 parts per million (ppm) NO_x corrected to 15 percent oxygen (equivalent to about 7 g/hph or about 2.2 lb/MMBtu fuel input) (2) for diesels burning oil or oil/natural gas combinations (39). This is an order of magnitude higher than emission rates from other combustion sources such as industrial boi!ers or even gas turbines (38). "Typical" uncontrolled NO_x levels from diesels are 11 g/hph (about 3.5 lb/MMBtu) for oil-fired engines and 8 g/hph (about 2.5 lb/MMBtu) for dual-fuel engines (39). As noted above, emission levels vary widely among different engine manufacturers and models.

Table 52 lists the wide variety of control options available to reduce NO_x emissions. In its efforts to formulate the internal combustion engine NSPS, EPA concluded that, of the methods shown in table 52, only retarded ignition timing, air-to-fuel ratio changes, decreased manifold air temperatures and engine derating were demonstrated to be effective and readily available for large engines (39). Exhaust gas recirculation and combustion chamber modification were considered to require additional development and durability testing, and the remaining methods were considered to have serious technical or cost problems, or to be of uncertain effectiveness for these engines.

The available control techniques do not work identically on diesel, dual-fuel, and natural gas-fired spark-ignition engines. Table 53 shows which techniques will achieve emission reductions of 20, 40, and 60 percent for the three engine types; the table also shows the expected increases in fuel consumption with these levels of emissions reductions. The increased fuel use, combined in some cases with higher maintenance costs and capital charges from add-on equipment, can cause significant increases in total costs; table 54 shows the increases in total annualized costs for different control types and emission reductions applied to diesel engines. ignition retard, with or without an air-to-fuel ratio change, and a combination of air-to-fuel change and manifold cooling can reduce NO_x emissions by 40 percent with total annualized cost increases of less than 10 percent. This level of control was selected by EPA for its proposed NSPS, although the proposal was withdrawn.

More recent information implies that greater NO_x emission reductions than those indicated by EPA may be possible. For example, although **EPA rejected water induction as a viable control strategy because of its potential for corrosion and oil contamination (39), the use of fuel/water emulsions or carefully timed direct injection apparently can bypass these problems (15). Control** levels

*A draft has been prepared by the Radian Corp.

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Table 52.—Summary of NO_x Emission Controi Techniques for Reciprocating IC Engines

Control	Principcle of reduction	Application	BSFC[a] Increase	comments-limitations
Retard Injection (CI)[b] Ignition (SI)[c]	Reduces Desk temperature by delaying start of combustion during the com-ustlon period.	An operational adjustment. Delay cam or Injection pump timing (Cl); delay ignition spark (SI).	Yes	Particularly effective with moderate amount of retard; further retard causes high exhaust temperature with possible valve damage and substantial BSFC Increase with smaller NO_x reductions per successive degree of retard.
Alr-to-fuel(A/F) Ratio change	Peak combustion temperature Is reduced by off-stolchiometrlc operation	An operational adjustment. Increase or decrease to operate on off-stoichiometric mixture. Reset throttle or Increase air rate.	Yes	Particularly effective on gas or dual fuel engines. Lean A/F effective but Ilmited by mlsfirlng and poor load response. Rich A/F effective but substantial BSFC, HC, and CO Increase. A/F less effective for diesel-fueled engines.
Derating	Reduces cylinder pressures and temperatures.	An operational adjustment, limits maximum bmep[d] (governor setting).	Yes	Substantial Increase In BSFC with additional units required to compensate for less power. HC and CO emission increase also.
Increase-speed	Decreases residence time of gases at elevated temperature and pressure.	Operational adjustment or design change.	Yes	Practically equivalent to deratlng because bmep is lowered for given bhp requirements. Compressor applications constrained by vibration considerations. Not a feasible technique for existing and most new facilities.
Decreased Inlet manifold air temperature	Reduces peak temperature.	Hardware addltlon to increase aftercooling or add aftercoollng (larger heat exchanger, coolant pump).	No	Ambient temperatures limit maximum reduction. Raw water supply may be unavailable.
Exhaust gas recirculation (EGR)				
External	Dllutlon of incoming combustion charge with inert gases. Reduce excess oxygen and lower peak combustion temperature.	Hardware addition; plumbing to shunt exhaust to Intake; coollng may be required to be effective; controls to vary rate with load.	No[e]	Substantial fouling of heat exchanger and flow passages; anticipate increased maintenance. May cause fouling in turbocharged, aftercooled engine. Substantial Increases In CO and smoke emissions. Maximum recirculation Ilmlted by smoke at near rated load, partlcularly for naturally aspirated engines.
Internal:				
Valve overlap or retard	Cooling by increased scavenging, richer trapped air-to-fuel ratio.	Operational hardware modification: adjustment of valve cam tlmlng.	Yes	Not applicable on natural gas engine due to potential gas leakage during shutdown
Exhaust back pressure	Richer trapped air-to-fuel ratio.	Throttling exhaust flow.	Yes	Limited for turbocharged engines due to choking of turbocompressor.
Chamber modlflcation Precombustion (Cl) Stratified charge (SI)	Combustion In antechamber permits lean combustion In main chamber (cyllnder) with less available oxygen.	Hardware modification; requires different cylinder head.	Yes	5 to 10 percent increase In BSFC over open-chamber designs. Higher heat loss implies greater cooling capacity. Major design development.
Water Induction	Reduces peak combustion temperature.	Hardware addition: inject water into inlet manifold or cylinder dlrectly; effective at water-to-fuel ratio 1 (lb H_2)/lb fuel).	No	Deposit buildup (requiring demineralizatlon); degradation of lube oil, cycling control problems
Catalytic *conversion*	Catalytic reduction of NO to N_2.	Hardware addition; catalytic converter installed In exhaust plumbing or reducing agent (e.g. ammonia) injected Into exhaust stream.	No	Catalytic reduction of NO is difficult in oxygen-rich envlronment. Cost of catalyst or reducing agent high. Little research applied to large-bore IC engines.

aBSFC-brake specific fuel consumption.
bCompression Ignition.
cSpark Ignition.
d bmep—brake mean effactlve pressure.
e If EGR rates not excessive.

SOURCE: Environmental Protection Agency, *Standards Supporf and Environmental Impact Statement for Stationary Internal Combustion Engines* (EPA-450/2.7&125a, draft, July 1979).

Table 53.—NO_x Control Techniques That Achieve Specific Levels of NO_x Reduction

NO_x reduction	Diesel		Dual fuel		Natural gas	
	Control (amount)	△ BSFC,[a] %	Control (amount)	A BSFC,[a] °/0	Control (amount)	A BSFC,[a] °/o
20%0	Retard (2° to 4°)	o to 4	Retard (2° to 3°)	1 to 3	Retard (4° to 5°)	1 to 4
	External EGR *(7%)*	*o*	Manifold air coollng	1	Manifold air cooling	0
	Derate (25 to 5070)	*3* to *5*	External EGR (lO%)	1	External EGR *(4%)*	*o*
	Air-to-fuel change (25%)	10	Derate (12 to 25%)	O to 8	Derate (5 to 35%)	2 to 6
	Retard and manifold air cooling	o to 1	Air-to-fuel changes (5 to IO%)	o to 2	Air-to-fuel change (570)	2
	Retard and manifold air cooling and air-to-fuel change	o to 1				
40%	Retard (7 to 8°)	4 to 8	Retard (5°)	2	Retard (10°)	2
	Derate (50%)	14 to 17	Manifold air cooling	1	Derate (10 to 50%)	2 to 24
	Air-to-fuel change and manifold air cooling	3 to 5	Derate (30 to 50%)	2 to 8	Air-to-fuel change (7%)	2
	Retard and air-to-fuel change	3 to 5	Air-to-fuel change (lO%)	2	Retard and manifold air cooling and air-to-fuel change	7
			Retard and manifold cooling	3		
60%	Retard (16°)	19 to 24	Retard (6°)	2	Derate (10 to 50°/0)	2 to 22
	Retard and air-to-fuel change	21	Derate (50%)	12	Air-to-fuel change (8 to 12%)	2 to 5
			Retard and air-to-fuel change	1 to 3	Retard and manifold air cooling and air-to-fuel change	7

[a] △ BSFC - change In brake specific fuel consumption.

SOURCE: Environmental Protection Agency, *Standards Support and Environmental Impact Statement for Stationary Internal Combustion Engines* (EPA-450/2-78-125a, draft, July 1979).

Table 54.-Costs of Alternative NO_x Controls for Diesel Cogenerators (percent Increase In total annualized costs)

NO_x control Percent reduction	Retard (R)	Derate	External EGR	Air to fuel (A)	R + M[a]	R + M + A	R + A	A +M
200/0	o-3	9-31	6	8	2	3		
40%	3-6	37-40					4	4
60%	14-18						16	

[a]Manlfold air cooling.

SOURCE: Office of Technology Assessment, from Environmental Protection Agency, *Standards Support and Environmental Impact Statement for Stationarv Internal Combustion Englnes* (EPA-450/2-78-125a, draft, July 1979).

of 50 percent or greater have been achieved with these techniques, with some parallel decreases in particulate emissions* (43). Another, more speculative NO_x control approach is the use of catalytic reduction systems. The staff of the California Air Resources Board (CARB) reports that NO_x reductions of 90 to 95 percent can be obtained from such catalytic systems (35). They also expect the systems to reduce CO emissions by 80 percent and hydrocarbon emissions by 75 percent. Catalytic reduction systems are currently available for rich-burning natural gas spark-ignition engines, and the CARB staff expects them to be available for the other engine types within a year or so, at costs below 10 percent of total annualized costs (3). However, this projection is viewed with various degrees of skepticism by other researchers (2).

*Wilson (42) reported that water/fuel emulsion achieved 50 percent NO_x reduction at full engine load with no fuel penalty. At part-load (66 to 93 percent), NO, reductions of 75 percent were achieved with a combination of exhaust gas recirculation and water/fuel emulsion.

Combustion Turbines

The Federal NSPS for large combustion turbines (above 100 MMBtu/hr) is 75 ppm NO_x corrected to 15 percent oxygen, which is equivalent to about 0.3 lb/MMBtu NO_x (40). For comparison, a typical emission factor for NO_Y emissions from an industrial boiler burning distillate oil is about half as much, or 0.16 lb/MMBtu (38). “Typical” uncontrolled NO_x levels from turbines are 0.6 lb/MMBtu for natural gas-fired engines and 0.9 lb/MMBtu for oil-fired engines (40). However, the variation in emissions among different turbine designs and sizes and even in the same turbine under different operating conditions is extremely high. Thus, the "typical" values are of limited usefulness in air quality analyses.

The most widely used emission control systems for combustion turbine NO_x emissions are so-called "wet" controls, which consist of water or steam injection into the combustion zone of the turbine. The injected fluid absorbs some of the heat of reaction, reducing peak combustion temperatures and, consequently, the rate of NO_x formation. This control is accepted by the industry and does not have significant adverse side effects. Generally, a water/fuel injection ratio of 1.0 will produce a 70- to 90-percent reduction in NO_x emissions, with a loss of fuel efficiency of 1 percent (40).

This range of control effectiveness, coupled with the variability in uncontrolled emission levels, results in actual controlled emissions that vary widely. EPA has measured "controlled" NO_x emissions of 15 to 50 ppm for gas-fired turbines and 25 to 60 ppm for oil-fired turbines (40). This implies that appropriate selection of turbine design could allow the use of turbines in certain situations where an "NSPS" turbine would be unsatisfactory.

Still more stringent control may be available by adding so-called "dry" controls. These are operating or design modifications such as exhaust gas recirculation, two-stage combustion, catalytic combustion, and other types of modifications. NO_x reductions of at least 40 percent have been demonstrated for some dry controls, and this reduction should be additive to any achieved with wet controls (40).

Finally, catalytic exhaust gas cleanup systems achieving NO_x reductions of 80 to 90 percent have been tested (40). Although these systems do not appear to be economically competitive with wet and dry controls, they could be useful if fuels with high nitrogen content were to be used (otherwise, the only viable control for NO_x generated by fuel-bound nitrogen is two-stage combustion) (40).

EPA has calculated the net NO_x emission control costs using wet controls for a baseload 4,000 hp industrial turbine. For a plant located close to a water source, the controls cost about 0.6 mills/kWh v. a total electricity cost of 32.5 mills/kWh, or a 1.75-percent increase (40). Transporting water for a turbine located in an arid climate could add considerably to this cost, however. Considering this and other cost variables, EPA considers the range of potential control costs to achieve the 75 ppm NSPS to be about 1.5 to 10.0 percent of the electricity cost for industrial turbines (40).

Health Effects From Cogenerator Emissions

Theoretically, any allowed increases in the deployment of cogeneration technologies should have no significant adverse effects on human health due to the protection afforded by environmental standards—especially the National Ambient Air Quality Standards (NAAQS). As discussed above, however, these standards might be violated because of ineffective permit review processes that miss "micro" (close to the emission source) effects in urban areas or that allow small cogenerators to escape careful analysis. The smallest cogenerators generally will be diesels, and these may therefore have the highest potential to escape detailed review of monitoring and, possibly, to pose health hazards. Judging from the emissions balances displayed in table 53 and from other environmental analyses of cogeneration, the pollutants of major concern are NO_x, sulfur dioxide (SO_2), and particulates-the latter not because of a high emission rate but because of their toxic character.

Due to of a variety of difficulties in measuring the health effects of pollutants, several of the Federal ambient standards–especially the standard for SO_2—have been criticized severely. A recent review in the Journal of the Air Pollution Control Association (JAPCA) concludes, however, that the standards "seem adequate to protect the health of the public" and, "until more data are available . . . should not be changed" (20). On the other hand, a number of other researchers disagree, arguing that some of the standards have proved to be unnecessarily stringent (23). The health and other considerations relevant to evaluating the NAAQS for SO_2, NO_x, and particulate are reviewed briefly below.

Sulfur Oxides

The 80 ug/m^3 long-term standard for SO_2 is the most controversial NAAQS because of the substantial expense involved in reducing sulfur emissions and, until recently, the lack of firm evidence of adverse health impacts from SO_2 exposure even at levels several times the current standards. Recent experiments, however, have demonstrated health effects in asthmatics (increases in bronchoconstriction) at levels near the current 24-hour standard (36). Also, exposure to SO_2 virtually always occurs in the presence of particulate and other gases, and generally there is a heightened response from the combination of pollutants. At levels around the ambient standards (100 ug/m^3 SO_2 and 150 ug/m^3 particulates, annual averages), respiratory symptoms, including general lung function impairments and increased asthma attacks, have been detected (33).

Nitrogen Oxides

The form of most of the NO_x emitted directly by diesels and other cogenerators is nitrous oxide, or NO; eventually, the NO is transformed by photochemical oxidation to the far more toxic NO_2. Because this oxidation takes sometime, the danger associated with a cogenerator's plume impacting on nearby buildings or the ground is considerably lessened.

At levels that maybe experienced in polluted areas (a few hundred ug/m^3), NO_2 appears to be associated with lung irritation in asthmatics and some increases in respiratory illness in the general population. According to the JAPCA review cited above, the epidemiologic evidence for the latter effect is not particularly strong (20). In any case, there seems to be little disagreement that the 100 ug/ms (annual average) ambient standard is adequate to protect public health. EPA currently is investigating the need for a short-term standard to protect against the acute effects of brief pollution episodes. It appears likely that this standard will be no stricter than about 500 ug/m^3 for 1 hour.

Diesel Particulate

Aside from their relatively high levels of NO_x and CO emissions compared to alternative combustion technologies, diesel cogenerators face the additional problem of producing particulate emissions that **may** cause adverse health effects. These effects, if they occur, would most likely stem from toxic substances such as polycyclic organic material that adhere to the carbon core of the exhaust particles. The small size of the particles complicates their control, allows them to remain airborne for weeks at a time, and allows deep penetration into and retention by the lungs.

The National Academy of Sciences recently released a report on diesel exhaust health effects that stresses the uncertainties in measuring the potential for adverse effects of these exhausts, while emphasizing that conclusive evidence of harm is not available (25). Some of the conclusions of the report are:

- Although current epidemiologic evaluations (statistical analyses of human populations) are inadequate, the available evidence shows no excess risk of cancer from diesel exhaust in the populations studied.
- Organic extracts (in which the potentially harmful organic compounds are removed, using a solvent, from the carbon particles to which they adhere) of diesel particulate have been shown to be mutagenic and carcinogenic in animal cell and whole animal skin applications. The mutagenic and carcinogenic potencies of these organic extracts appear to be similar to those of extracts of gasoline engine exhaust, roofing tar, or coke-oven effluent.
- Unlike the extracts, inhaled whole diesel exhaust has not been shown to be carcinogenic or mutagenic in laboratory animals. A possible reason for this could be that many of the potentially dangerous compounds may not be released from the particles and thus may not become biologically available to cause harm. *

*However, another reason could be that the tissue tests used for these investigations do not adequately reflect what would actually go on inside the body.

- Potentially toxic particles can accumulate in the lungs when diesel exhaust is inhaled, but long-term effects are uncertain. In the short term, cell damage (mostly reversible) can occur because the diesel exhaust can adversely affect the lungs' defense and clearance mechanisms; it is not clear if this is caused by the particles or by the gases in the exhaust.
- The design and operating characteristics of the engine may be a significant determining factor in the carcinogenicity of diesel engine exhaust materials.

Evaluating the potential for harm of diesel particulate from cogenerators is complicated by differences in operating characteristics between cogenerators running at constant speeds and relatively stable loads, and mobile sources running at varying speeds and loads. Mobile sources (from which most of the emission data have been gathered) operate at far less optimal combustion conditions and produce more particulate matter. It is not unreasonable to speculate that the human health risk from diesel cogenerators **per unit of energy input or output** may be significantly lower than the risk from mobile diesels; however, scientific data with which to confirm or deny this speculation do not appear to be available.

Effects of Some Other Cogeneration Technology/Fuel Options

Although oil-fired and dual-fuel diesels, oil- and natural gas-fired combustion turbines, and multifuel steam turbines are the most likely cogeneration options for the immediate future, other technology or fuel choices will be open to potential cogenerators.

Spark=Ignition Engines

Fiat recently introduced a natural gas-fired spark-ignition cogenerator—called TOTEM–based on its automobile engines. Because the TOTEM modules are extremely small (15 kw), they may escape careful permitting by local authorities. Proliferation of such cogenerators in urban areas could conceivably lead to air quality problems.

EPA data indicate that gas-fired spark-ignition engines have higher NO_x emissions than diesels (sales-weighted average of about 4.6 lb/MMBtu v. about 3.5 lb/MMBtu for diesels) (39). On the other hand, Fiat and Brooklyn Union Gas claim NO_x rates of about 3 lb/MMBtu as well as extraordinarily high thermal efficiencies (91 percent) that would maximize the emission displacement of the cogenerator (6). Either emission level can present a problem, however, because the small TOTEM engines would not be subject to the proposed NSPS for stationary internal combustion engines, and even the lower rate is quite high in comparison with competing combustion sources.

Alternate-Fuel Diesels

Although natural gas/diesel fuel mixtures and straight diesel fuel are used in stationary diesels today, residual fuel currently is used in large marine diesel engines and will be available for stationary engines. Coal-derived fuels in the form of synthetic oil, coal slurry, and dry powdered coal may be used in future engines (see ch. 4).

Use of residual oil in diesels should affect SO_x emission levels because residual oil generally has higher sulfur levels than distillate fuels. According to available data, however, levels of other emissions should not be affected significantly in comparison to current diesels (27). Diesels using coal-derived synthetic residual oil exhibit similar characteristics, although synfueis that have not been hydrotreated will contain levels of fuel-bound nitrogen that are generally higher than those in natural oils and consequently will cause elevated NO_x emissions (24).

The use of coal slurries and powdered fuels should adversely affect levels of NO_x, SO_x, and particulate. Table 55 shows expected values of

Table 55.-Emissions From Oii- and Coai-Fired Dieseis

Fuel	Emissions (lb/M MBtu) NO.	so..	Particulate
Diesel Oil[a]	3.46	0.2[c]	0.07
Coal slurry[b]	3.61	I.5[d]	3.26
Coal[b]	4.35	1.5[d]	8.91

aSource is app. A.
[b]Reference 47.
cAssumes 0.2% sulfur distillate oil.
dAssumes 2% sulfur coal, 25 MMBtu/ton.

these fuels compared to average emissions from oil-fired diesels. The level of particulate emissions is so high as to virtually guarantee that an uncontrolled coal-fired engine would be environmentally unacceptable. Based on an extrapolation from ConEd modeling studies (19), it is possible that a proliferation of such diesels in urban areas would create significant problems with all three pollutants unless emission controls were used.

Atmospheric Fiuidized Bed

Steam turbines using coal-fired atmospheric fluidized bed (AFB) boilers can achieve low SO_x emission rates without generating large amounts of scrubber sludge, and probably will have NO_x emissions below current NSPS for steam turbines. Although the action of the bed creates potentially high levels of particulate emissions, baghouse controls should keep actual emissions to ve~ low levels. The AFB boiler at Georgetown University in Washington, D.C. (which is a **potential** cogenerator although it currently does not generate electricity) has now been operating without environmental complaints for a few years.

Closed-Cycle Gas Turbines

Closed-cycle gas turbines use an external heat source to produce high-temperature gas. Although emissions depend on the nature of the heat source and fuel used, emission control should present no unusual problems.

Methanol-Fired Gas Turbines

There is a reasonable probability that significant quantities of methanol from biomass and coal resources may become available within a few decades. Methanol is a suitable fuel for gas turbines and might be an advantageous fuel in turbine cogenerators because of the expected substantial drop in NO_x emissions. Methanol has achieved 76-percent reductions in NO_x emissions from large turbines because it has a significantly lower combustion temperature than distillate fuels (28).

Policy Options: Removing Environment= Associated Regulatory Impediments

In general, Federal, State, and local authorities treat cogenerators in an identical fashion with other stationary combustion sources. For example, both Federal NSPS and local emission standards for all combustion sources are tied to fuel input rather than energy output, and thus do not consider the energy efficiency of the system. In other words, two diesel generators that use the same amount of fuel are limited to the same levels of emissions, even if one produces more usable energy than the other. Also, facilities are designated as "major sources" subject to PSD and nonattainment review only on the basis of their emissions output, without consideration of any emissions reductions their use might cause in other facilities. Finally, new sources locating in nonattainment areas are awarded emission offsets only to the extent that other sources within the same locale agree to reduce their emissions permanently and transfer the pollution rights obtained by the reduction to the new source. Thus, cogenerators are not automatically given preferred treatment to account for their increased efficiency or their displacement of centrally generated electricity.

It has been suggested that cogenerators should be given various types of preferred treatment with regard to air quality concerns to facilitate their market entry (12, 16,22). Two basic changes that have been recommended are:

- That emissions standards account for high cogenerator efficiency, either by being tied to the energy ***output*** rather than the fuel ***input*** of the source, or by having separate (more lenient) standards for cogenerators.
- That restrictions on new sources under PSD and nonattainment area provisions of the **Clean** Air Act (see ch. 3) be reduced or eliminated for cogenerators. For example, the

250-tpy emissions trigger could be relaxed by allowing the cogenerator to subtract emissions that are eliminated at the central power station. Only if net ***emissions*** exceed the trigger levels would the provisions apply. An alternate or additional policy would be to shift the responsibility for obtaining emissions offsets to the State, or to allow the cogenerator to count any reduction in central station power generation as an offset.

Each of these policy alternatives is evaluated below.

Emission Standards Based on Output

Because cogenerators generally produce considerably more useful thermal and electric energy than the same equipment generating only electricity, basing emission standards on energy output rather than fuel input would significantly reduce the emission control requirements for cogenerators and should lower their overall costs. Thus, this policy would make cogeneration more competitive in the marketplace, although the extent of any advantage will vary substantially from case to case.

The major environmental argument for this policy alternative is that, for a given amount of useful energy, a cogenerator will produce less pollution than a separate generator and thermal energy source and thus should be rewarded for this benefit (4,41). This argument generally is valid only when a cogenerator would replace an otherwise identical generator, using the same technology and fuel. As discussed above, many cogenerator applications involve new technology or fuel substitutions (e.g., diesel cogenerators replacing steam turbines and boilers or furnaces), as well as changes in scale. As shown in the section on emissions balances, the net result is quite often an emissions **increase.** Furthermore, the pollution impact of most concern often is the local air quality impact, and this may not be improved by the reduced emissions at a distant powerplant as a result of the addition of cogeneration. Finally, the legislative philosophy associated with NSPS is that all important new stationary sources should apply the best control technology available to them, taking into account energy, economic, and non-air quality environmental factors. Some potential cogenerators might try to argue that these energy and other considerations justify a different interpretation of "best technology" in their case. Based on the analysis of the environmental costs and benefits of cogeneration in this report, however, it appears that such an argument would not be valid for all cogenerators. Thus, cogeneration emission standards based on energy output should only be applied on a case-by-case, or technology- and area-specific basis, if at all.

Changes in Offset Requirements

As shown in table 56, the costs incurred in being designated a "major source" under either PSD or nonattainment area provisions are high and will affect the economic attractiveness of cogeneration (17). In addition to the costs of performing the necessary environmental analyses, the added costs of obtaining emissions offsets (if any are available) and installing lowest achievable emission rate (LAER) controls may effectively block cogenerators (and most other types of stationary sources) from locating in nonattainment areas. Thus, policies that reduce or eliminate the review requirements (and, for nonattainment areas, the offset requirements) for cogenerators would be removing important impediments to these technologies.

The major argument against automatically crediting the reduction in central station power requirements in applying PSD and nonattainment

Table 56.-Approximate Costs of Procedures Required Under the Clean Air Act

Procedure	cost to cogenerator
Engineering review	$100-500
Stage 1 PSD review (attainment)	$1,000-2,000
Monitoring—1 year	
One pollutant	$30,000
Six pollutants	$125,000
Stage 1 interpretive ruling (nonattainment)	$2,000
TSP/SO_2 modeling	$10,000-20,000

NOTES: Any of these costs may or may not be incurred, depending on the individual case. These figures assume a simple, "major source" case.

SOURCE: Office of Technology Assessment, from Michael S, Dukakis, *Governor's Commission on Cogeneration, Cogeneration: Its Benefits to New England* (Governor of Massachusetts, October 1978).

rules is that the benefit of this reduction to the airshed in question is often either illusory or very difficult to calculate. As noted previously, the corresponding emission reduction may be out of the airshed altogether, or the reduced power requirements may be shifted among different plants at different times according to the utility's economic dispatch methods and the overall supply/demand balance of the grid. Also, when the central powerplant has a very tall stack, its effect on the air quality of a particular airshed maybe far less, per unit of power, than the effect of cogenerators. Finally, in the case of a large new cogenerator, the "offset" utility emissions may be from a projected powerplant rather than from an existing facility. Because any future powerplant would have to comply with PSD or nonattainment requirements if its emissions affected the airshed, it is not logical that the plant's replacement or "offset" —the cogenerator—should be freed from these requirements.

To summarize, these policy alternatives do appear to be attractive if the primary objective is to promote cogeneration. However, **widespread** application of regulatory relief to cogenerators **as a class** is difficult to justify on environmental grounds. On the other hand, the existence of situations where air quality benefits and oil savings will accrue from cogenerators may justify awarding some relief on a case-by-case or technology- and area-specific basis.

Other Potential Impacts

Although the potential air quality effects are the major environmental concern associated with cogeneration systems, potential impacts from water discharges, solid waste disposal, noise, and cooling tower drift are important and must be addressed satisfactorily to avoid local opposition to these cogenerators.

Water Quality

Water discharges are associated primarily with blowdown from boilers and wet cooling systems. Pollutants of concern are suspended solids, salts, chlorine, oil and grease, and chemical corrosion inhibitors. For large coal-fired steam turbine cogenerators, potential discharge sources include runoff from coal storage piles, scrubber effluent from $S0_2$ control systems, and discharges from ash quenching. These discharges are the same as would occur in conventional steam turbine combustion systems, although any wet cooling systems clearly would be smaller because much of the waste heat is captured in a cogenerator and need not be discharged to the environment. Some of the discharges may present special problems, however, because the cogenerators may be located in urban areas whose sewage treatment facilities are not designed to handle industrial discharges. Onsite pretreatment (before discharge into the municipal system) may be necessary to avoid problems from these discharges.

Solid Waste Disposal

Disposal of ash and scrubber sludge could also present some difficulties for urban and suburban coal-fired cogenerators due to the lack of secure landfill areas. Municipal landfills may be inadequate due to the toxic metals content of the ash, and long-distance and expensive shipping of these wastes might be necessary.

Noise

Operating cogenerators and trucks supplying fuel to cogenerators may produce high noise levels in urban areas. For example, a recent study of the Jersey City Total Energy Demonstration project, which uses diesel cogeneration, measured sound levels of 65 dB(A) (loud enough to interfere with a normal conversation) at a distance of 75 ft from the equipment building (1 3). This might be considered unacceptably loud for a night-time noise level in a residential area. Similarly, the noise from fuel trucks may be considered disruptive, although the effect of supplying oil-fueled furnaces and boilers may be as disruptive, if not more so, because furnaces and boilers are likely to require more frequent fuel deliveries than cogenerators. In any **case, noise** control measures are readily available. These include careful scheduling of fuel deliveries, installing mufflers, or adding sound absorbing materials to equipment and buildings to reduce engine noise.

Cooling Tower Drift

Cooling tower drift-the discharge and dispersal of small droplets of water from wet cooling towers—is a potential source of problems in urban areas. These droplets will contain anticorrosion chemicals and biocides and will have a high salt content caused by the concentrating effect of the evaporative cooling. In the Jersey City demonstration project mentioned above, inadequate maintenance of the system led to spotting of nearby automobiles and an annoying misting of pedestrians (1 3). Although the effects in the Jersey City case appear to represent a nuisance rather than a hazard, negative community reaction to this as well as other visible adverse effects of cogenerators may play a significant role in their further deployment.

POTENTIAL REGULATORY BURDEN ON ENVIRONMENTAL AGENCIES

Cogeneration usually involves shifting environmental impacts-primarily effects on air quality—away from a few central powerplants to a larger number of small sources. Although cogeneration will not be subject to as many permitting requirements as large central generating plants (see ch. 3), multiple installations could lead to increased permit applications and more sources that must be monitored and inspected. In some areas, State and local environmental protection agencies may not have the resources to accommodate such an increase in their workload. If this is the case, cogenerators could be inadequately monitored and controlled, and substantial adverse impacts could occur (see discussion of environmental impacts, above). *

To determine whether cogeneration would significantly increase the workload of environmental agencies, OTA first estimated current workloads and resources of the various Federal and State permitting agencies in two States–Colorado and California—based on interviews with agency personnel.** Those interviews also revealed current management concerns about existing and future caseloads. Then the increased permitting, monitoring, and enforcement responsibilities attributable to cogeneration were calculated from State agency market penetration projections, and compared to the existing workloads to determine the potential regulatory burden.

*The analysis in this section is drawn from Energy and Resource Consultants, Inc. (17).

**In Colorado, the Department of Natural Resources, the Office of Energy Conservation, and the Colorado Energy Research Institute were contacted. In California, the California Energy Commission and the Cogeneration Task Force were contacted.

The results of this analysis suggest that cogeneration is likely to have a minimal impact on environmental caseloads in these two States because the increase in agency resources needed to regulate cogeneration is very small when compared to existing workloads. Possible exceptions would be areas where agencies were already understaffed prior to the Federal (and many State's) budget reductions of 1981 and 1982–usually water quality and right-of-way programs, or where economic or other legislative incentive programs for cogeneration impose significant new responsibilities on agency staff.

Environmental Permitting and Enforcement Agencies

Four regulatory agencies in **Colorado** have direct jurisdiction over cogeneration facilities, while approximately seven others regulate associated facilities such as transmission and distribution systems.

Permitting and enforcement of the Clean Air Act are shared by the region Vlll offices of EPA and the Air Pollution Control Division of the Colorado Department of Health. The division administered approximately 400 permits in 1980 and conducted approximately 4,900 inspections. Discussions with agency personnel revealed no major enforcement problems in 1980. EPA region Vlll administers the PSD program in Colorado. They processed 40 to 50 permit applications in 1980 and they typically conduct oversight inspections of roughly 10 percent of the major sources in the State each year.

The water programs are administered by the Water Quality Control Division of the State Department of Health and by the Army Corps of Engineers. The Water Quality Control Division administers the section 401 and the National Pollution Discharge Elimination System (NPDES) permits. The section 401 program (primarily applicable in this context to transmission and distribution systems) had one staff member who issued 200 water quality certificates in fiscal year 1980. The NPDES program also suffers from insufficient manpower; almost 300 applications for new permits or for amendments to existing permits were awaiting action at the end of 1980. Time pressures on the staff members are felt to impair the quality of the reviews for permits being issued, possibly resulting in inadequate controls. The Water Quality Control Division initiates 30 to 45 enforcement actions per year, but many violations by minor sources are ignored due to lack of manpower.

The Army Corps of Engineers administers the section 404 permits through their district offices in Sacramento and Omaha. The Sacramento District maintains an area office in Grand Junction, Colo., with three full-time personnel. In 1980, this office issued approximately 40 applications for section 404 or section 10 permits in process, 50 violations (generally involving unpermitted work—their biggest problem), and 150 to 175 individual permits (these have a normal term of 3 years, with extensions available). They also supervised approximately so operations under general permits.

Applications for rights-of-way in Colorado are handled by the State Board of Land Commissions, the Bureau of Land Management (BLM), and the U.S. Forest Service. Right-of-way applications have been a bottleneck in the permitting process, with application processing lasting up to 1 year.

In summary, the programs concerned with water quality (sec. 401, sec. 404, NPDES) are at present less effective than they might be, due largely to manpower limitations. Delays in processing right-of-way applications in the district offices of BLM and the Forest Service, which in large measure reflect manpower limitations, change from year to year and district to district, reflecting the variability in applications filed and resources at each district. If dispersed facilities sharply increased the number of right-of-way applications, this permit could become a severe bottleneck.

California environmental agencies are subdivided into numerous regional and district offices (see ch. 4). For example, 46 separate air pollution control districts (APCDS) are responsible for administering air permits and each district has different permitting requirements. As a result, only sampled agency districts or regions that are considered representative are discussed explicitly.

The 46 APCDS in California vary from rural counties with one full-time employee, to the Bay Area and South Coast Air Quality Management Districts with over 200 and 400 full-time employees, respectively. The Sacramento County APCD employs two people to permit 150 to 200 sources per year. permits require up to 2 months to be processed. There are no sources in the district with continuous monitoring, and one of three inspectors visits each major source from two to five times per year. Telephone contacts with these and other APCDS revealed no major enforcement concerns in 1980.

The nine Regional Water Resources Control Boards administer the waste discharge requirement program in California. Region 5, headquartered in Sacramento, has approximately 20 personnel to handle all phases of the program. Approximately 150 permits are issued each year, 25 percent of which are NPDES permits. Major sources are inspected twice a year, minor sources perhaps once every 3 years, and about 2,000 sources maintain self-monitors and report quarterly to the regional board. Telephone contacts with these and several other regional boards revealed no major management problems.

California is included in two Corps of Engineers Districts, Los Angeles and Sacramento. The "navigation" branch of the Los Angeles District is in charge of permitting and enforcement under the section 404 program. The Corps presently suffers from a manpower shortage, as revealed by the increased number of unresolved violations (from

66 to 78); enforcement generally is the lowest priority action for the district.

Rights-of-way for dispersed generating facilities in California will be sought from three agencies: the State Lands Commission, BLM, and the Forest Service. Conversations with agency personnel indicated that at present they were adequately staffed in 1980, with the possible exception of the Forest Service.

In summary, the information collected regarding the caseloads and personnel of California environmental agencies showed them to be, in general, better staffed than their counterpart agencies in Colorado. However, legislation enacted in California in 1981 that requires the State Air Resources Board and the APCDS to mitigate the air quality impacts of cogenerators smaller than 50 MW, and to secure offsets for them, could tax the resources of the APCDS. Also, as in Colorado, the agencies administering the water programs (NPDES, sec. 404 and sec. 401 programs) appear to suffer from manpower shortages that result in lax enforcement. Finally, the rights-of-way for facilities on Federal lands administered by BLM or the Forest Service could be a bottleneck in the permitting process if the number of applications increased significantly or the number of personnel to process them decreased.

Potential Impacts on Agency Caseloads

Few market penetration estimates are available for cogeneration (see ch. 5). Therefore, to gauge the effects of cogeneration permitting and enforcement on agency caseloads, State agencies primarily responsible for cogeneration's development or regulation were contacted and asked to provide their best estimates for potential development through 2000. The results of this informal survey are presented in table 57. It should be emphasized that these are not official or precise estimates based on any formalized methodology, but instead typically were the result of "brainstorming" sessions held by agency personnel. To determine the permit and other regulatory requirements of the amount of cogeneration capacity shown in table 57, assumptions were made concerning, among other things, the size and location of the facilities.

Table 57.—Penetration Scenario for Cogeneration in California and Coiorado

Year	MW capacitv installed	
	California	Colorado
1985	1,700	170
1990	2,300	230
1995	3,600	360
2000	6,000	600

SOURCE: Energy and Resource Consultants, Inc., *Federal and State Environmental Permitting and Safety Regulations for Dispersed Electric Generation* Technologies (contractor report to the Office of Technology Assessment, 1980).

First, it was assumed that, in Colorado, all new cogeneration units will file an Air Pollution Emissions Notice (APEN). Second, PSD permits were assumed to be required under the Clean Air Act for all sources over 10 MW and for one-half of the sources under 10 MW. Third, 25 percent of cogeneration units were assumed to require an NPDES, section 401 or 404 permit under the Clean Water Act. Fourth, 25 percent of cogeneration units would require State and/or Federal rights-of-way, and 25 percent also were assumed to require consultations with wildlife and historical agencies.

The market penetration assumptions and their assumed regulatory requirements were combined to estimate the increased agency responsibilities for permitting and enforcement due to cogeneration. The results of this analysis must be viewed as one possible scenario out of many plausible futures due to the large uncertainties in working with informal market penetration estimates. However, it can be stated that the results presented below are a **high estimate** of the increased regulatory burden because the deployment assumptions described above are based on size or siting conditions that would result in many cogenerators being subject to the full range of regulatory requirements. If cogenerators tend to be smaller or located in different areas, then the increase in permitting and enforcement responsibilities would be less than that shown below.

Colorado

The projected increases in agency workloads in Colorado due to the future deployment of cogeneration technologies are presented in table 58. There is expected to be an increase of less

Table 58.—increase in Agency Workloads Due to the Deployment of Cogeneration Technologies in Colorado

Agencv	Current staff	Current case load	Projected average increases in cases per year 1981-85	1988-90	199; -95	1998-2000
1. Air Pollution Control Division, Colorado Department of Health:						
1. Air Pollution Emission Notices	4	480	2	3	4	7
2. Inspections	20	900	6	18	39	81
II. Region VIII–EPA:						
1. PSD permits	5	45	1	2	3	7
2. Inspections	8	300	3	9	18	39
III. Water Quality Control Division, Colorado Department of Health:						
1. NPDES permits	12	300	1	1	1	2
2. Sec. 401 certificates	1	200	1	1	1	2
3. inspections	12	1,000	3	6	9	15
IV. Army Corps of Engineers, Omaha District: 404 applications	20a	475[a]	1	1	1	2
Sacramento District: 404 applications (Colorado only)	4	40	1	1	1	2
V. State Board of Land Commissioners (right-of-way applications and commercial leases)	1	75	1	1	1	2
VI. BLM-State Office (right-of-way applications)	12	185	1	1	1	2
VII. State Division of Wildlife (consultations)	18	75	1	1	1	2
VIII. Colorado Historical Society (consultations)	6	1,200	1	1	1	2

a For the entire district.

SOURCE: Energy and Resource Consultants, Inc., *Federal and State Environmental Permltting and Safety Regulations for Dispersed Electric Generation Technologies* (contractor report to the Off Ice of Technology Assessment, 1980).

than 1 percent in annual APEN filings due to cogeneration during the 1981-85 period, and only a 3-percent increase (over the 1980 base year) during 1996-2000. Increases in other types of permits are even smaller.

The impact on **the number of inspections** can be greater (depending on the current caseload) due to the fact that a permit is only granted once, whereas each facility must be inspected every year. Thus, inspections are cumulative and the agency must inspect not only the facilities permitted this year, but also all facilities permitted in previous years that are still operating. Still, only a 10-percent increase in the number of required air pollution inspections is shown through 2000.

California

Table 59 presents a similar estimate of the potential impacts of cogeneration on agency workloads in California. These impacts are more difficult to quantify because data on air and water permit applications are tabulated on a regional or district basis, and statewide totals were not available. Table 59 is based on data from selected California air and water quality districts that tend to be representative of the potential statewide agency impact, but the table does not include the impact of the 1981 legislation (mentioned previously) that shifts the burden of attaining offsets under the nonattainment area provisions of the Clean Air Act to the local APCDS.

Table 59 shows that the projected number of air and water permit applications for cogenerators and the subsequent enforcement cases is greater in California than in Colorado due to the larger assumed penetration of cogeneration in California. However, California agencies tend to have more staff and other resources and thus the overall workload impact can be expected to be roughly similar. But, several of the California environmental agencies already are overextended and even a minor increase in the workload or reduction in staff may be difficult to accommodate under present conditions.

Table 59.—increase In Agency Workloads Due to the Deployment of Cogeneration Technologies in Caiifomia

Agency	Current staff	Current case load	Projected average increases in cases per year 1981-85	1986-90	1991-95	1996-2000
1. California Air Quality Division						
State-wide total	1,000+	NA	20	17	37	41
Sacramento District:						
1. New Source Review	2	175	1	1		1
2. Inspections	3	900	3	6	9	12
II. Water Resources Control Board						
State-wide total	NA	NA	5	4	9	10
Region 5—Sacramento:						
1. Waste Discharge Requirement[a]	20	150				2
2.inspections	—	1,500	3	6	9	12
Region 9—San Diego:						
1. Waste Discharge Requirement[a]	2	8	1		2	2
2. Inspections	17	1,000	3	6	12	18
III. Army Corps of Engineers						
Los Angeles District:						
404 applications	11	120	3	2	5	6
IV. State Lands Commission						
(rights-of-way)	100	450	5	4	9	10
V. BLM State Office						
(rights-of-way)	15	150	5	4	9	10
VI. Fish and Game Department						
(consultations)	35	10,000	10	9	19	20
VII. Office of Historic Preservations						
(consultations)	4	20	10	9	19	20

NA - Not available.

aThis encompassed both the 401 and NPDES permit programs.

SOURCE: Energy and Resource Consultants, Inc., *Federal and State Environmental Permitting and Safety Regulations for Dispersed Electric Generation Technologies* (contractor report to the Offlce of Technology Assessment, 1980).

Summary

The data in this discussion show that, in most cases, the deployment of cogeneration should only increase State and Federal agency caseloads by a small percentage. The resulting increases in staff workloads vary depending on present load and resources. But many of the agencies currently are understaffed and not able to handle their present caseload. Thus, even small percentage increases in workload would represent a substantial burden for these agencies. Moreover, under current policies designed to reduce Federal agency budgets and staff resources and turn over more of the responsibility for permitting, monitoring, and enforcement to already understaffed State agencies, the impact of cogeneration may be more significant than suggested by these data. If this is the case, then cogeneration projects could be delayed in the permitting process, or could be reviewed inadequately resulting in insufficient controls and enforcement, and therefore a greater potential for adverse environmental impacts.

ECONOMIC AND SOCIAL IMPLICATIONS

Cogeneration (and other onsite generating technologies) has attracted widespread attention not only for its potential benefits and costs for energy efficiency, the environment, and utility planning and operations, but also for its possible implications for the economic and political institutions traditionally involved in the supply and demand of electric and thermal energy. Many analysts feel that, as global stocks of oil and natural gas dwindle, major changes must occur in the technical, economic, and institutional context for energy supply and demand in industrialized societies. Cogeneration and small power production are likely to be a part of these energy system changes. Moreover, many people advocate the use of dispersed generating technologies not solely because of the perceived technical, economic, or environmental advantages, but also due to the belief that an energy system based on these technologies will be more compatible with traditional democratic, participatory, and pluralistic institutions than a strategy based on continued reliance on large-scale centralized technologies. Although a thorough assessment of these implications is beyond the scope of this report, some general considerations are discussed below.

In general, there are two ways in which technological change can be associated with social or political change: 1) a change in the number, type, or responsibilities of organizations associated with the production, distribution, and/or operation of a technological system; and 2) the more general benefits and costs for individuals, groups, and society as a whole. In the context of cogeneration, the first type of change relates primarily to those institutions described in chapter 3–the traditional suppliers, users, and regulators of electric energy, while the second set of impacts concerns the likelihood of cogeneration's resulting in greater centralization or decentralization in social organization.

The general background for an analysis of the social and political implications of cogeneration is described in chapter 3, including the national energy context, the current status of the electric utility industry, and the regulatory and institutional aspects of cogeneration. Clearly a fundamental feature of the electric utility industry-its ability to provide a reliable supply of electricity at a relatively low price while maintaining its financial health–has changed dramatically in recent years. Virtually all aspects of the technological and institutional context of the industry have contributed to this change: capital and fuel cost increases and environmental concerns have limited the choice of generating technologies and operating conditions, and have increased the price of electricity significantly. At the same time, the rate of demand growth has declined substantially, resulting in excess utility capacity in many areas, which has contributed to utilities' financial problems. As a result of these recent changes in the status of electric utilities, the industry and its customers and regulators have sought alternate means of achieving the goal of reliable service at a low price. One such means is through small-scale generating technologies such as cogeneration.

The widespread use of cogeneration could bring a wide array of changes to the context described in chapter 3. In general, these changes can affect the roles, responsibilities, or authority of energy suppliers or consumers and the relationships among them. Thus, with cogeneration, the traditional roles of utilities—as suppliers of electricity—and their customers would have to be recast as former customers feed cogenerated power into the grid, and thus become suppliers of electricity themselves. Alternatively, electric utilities could own dispersed cogeneration capacity and establish a new role for the industry as providing alternative energy supply options (and, in most cases, a new product–thermal energy) rather than merely facilitating the development of those options by other parties.

This section focuses on the economic and social implications of cogeneration for utilities and their customers. It begins with an analysis of the potential capital cost and employment impacts of three scenarios for cogeneration market penetration, discusses the effects of the scenario results on utilities' planning and operation, and then briefly outlines some potential impacts in other economic sectors. The section concludes with a review of cogeneration's implications for the centralization or decentralization of electricity generation.

Economic Impacts

Due to the large number of uncertainties about future energy development patterns, it is extremely difficult to develop a quantitative—or even qualitative—basis for comparing the economic characteristics of these different development scenarios. For example, the rate of growth in electricity demand, the rate of inflation, future capital costs for powerplant construction, and changes in the regulatory climate all may affect the future costs and deployment characteristics (e.g., plant size) of utility generating capacity. Similarly, uncertainties about ownership, future capital costs, and the choice of technologies make it difficult to project the economic effects of the widespread use of cogeneration. Furthermore, due to the lack of recent cogeneration experience, reliable data are not available for items such as the operating and maintenance (O&M) labor required for cogenerators. Without a large computer modeling effort, clearly beyond the scope of this assessment, it is not possible to determine the sensitivity of the economic impacts of cogeneration development to these uncertainties.

However, OTA wanted to be able to define the problem areas in order to lay the groundwork for future impact assessments. Therefore, OTA developed three rough market penetration estimates for cogeneration. The assumptions underlying these rough estimates and their derivation are reviewed briefly, and then the ranges of impacts that could be associated with each estimate are discussed.

Market Penetration Scenarios

A wide range of penetration estimates are available in the literature on cogeneration and are displayed in table 60. The highest estimate shown in the table—which represents 10 to 16 percent of total projected electricity generation capacity in the year 2000-is around 70 times larger than the smallest. To bracket the ranges of penetration estimates, OTA chose three estimates. The first, a penetration of 50,000 MW by 2000, is an approximation of the Economic Regulatory Administration's high estimate for the maximum oil/gas electric generating capacity potentially displaced by cogeneration. The implementation of 50,000 MW of cogeneration would represent approximately 5 to 8 percent of total projected installed generating capacity in 2000. Second, as the middle range, OTA chose the high number in table 60—approximately 100,000 MW of cogeneration–which would represent 10 to 16 percent of potential installed generating capacity in 2000. Finally, in order to gauge the impacts of phenomenal success, OTA postulated a penetration of 150,000 MW by 2000, which would be 16 to 24 percent of total projected installed capacity.

Table 60.-Market Penetration Estimates for Cogeneration

Source	MW	Qualifications
FERC	5,910	Estimate of the marginal increase in cogeneration capacity caused by PURPA by 1995.
FERC	27,405	Estimate of the potential for cogeneration capacity in 1995.
ERA	1,312	Amount initially allowed under FUA regulations.
ERA	3,920	Likely cogeneration penetration by 1990.
ERA	45,190	Maximum oil/gas-fired generating capacity potentially displaceable by cogeneration.
SERI	93,000	Amount of central station baseload capacity potentially displaceable by cogeneration.

KEY: FERC—Federal Energy Regulatory Commlssion; ERA—Economic Regulatory Admlnistration; and SERI—Solar Energy Research Instltute.

SOURCE: Off Ice of Technology Assessment.

Once these three penetration estimates were established, it was necessary to disaggregate for the types of utility generating capacity that would be backed out by cogeneration and in what parts of the country. In order to do this it was assumed that:

- 30 percent of existing oil-fired steam generating capacity would be converted to coal or permanently retired;
- oil-fired steam plants would be backed out before gas-fired steam plants;
- only oil- and gas-fueled capacity would be backed out (i.e., no coal, nuclear, hydro, or other non-oil/gas capacity is replaced by cogeneration);
- steam plants would be backed out before combustion turbines;
- oil-fired combustion turbines would be backed out before gas-fired combustion turbines; and
- no utility region would replace all its combustion turbine capacity with cogeneration, for reliability reasons.

Based on these considerations, three scenarios were derived from the following assumptions:

1. *50,000 MW penetration by 2000:*
   - 30 percent of the 1981 oil steam capacity would be converted to coal or retired

by 2000 and would not be available for replacement by cogeneration;
- of the remaining 70 percent of oil steam capacity, approximately 40 percent would be replaced by cogeneration;
- approximately 40 percent of the gas steam capacity would be replaced by cogeneration; and
- approximately 1 percent of the oil-fired combustion turbine capacity would be backed out by cogeneration.

2. ***100,000 MW penetration by 2000:***
   - ***30*** percent of oil steam would be converted or retired, and 75 percent of the remainder would become cogeneration;
   - 75 percent of the gas steam capacity would be backed out;
   - 18 percent of the oil combustion turbine capacity would be replaced by cogeneration; and
   - 11 percent of the gas combustion turbine capacity would be replaced by cogeneration.
3. 150,000 ***MW penetration by 2000:***
   - 30 percent of the oil steam capacity would be converted or retired, and 100 percent of the remaining oil steam would become cogeneration;
   - 100 percent of the steam gas capacity would be backed out by cogeneration;
   - 70 percent of the oil combustion turbine capacity would be replaced by cogeneration; and
   - 30 percent of the gas combustion turbine capacity would become cogeneration.

These assumptions were applied to the nine North American Electric Reliability Council regions based on 1981 regional oil and gas steam and combustion turbine capacity (i.e., the analysis assumes no new oil/gas capacity will be brought on-line after 1981, regardless of utility announced plans). Thus, these penetration estimates do no necessarily correspond to the regional cogeneration opportunities that have been identified in the literature. This is simultaneously a result of the linear approach to the analysis and a desire to gauge the impacts of overwhelming success for cogeneration policy and financial incentives. The results of this exercise are shown in detail in table 61.

Financial and Employment impacts

It has been claimed widely that investment in smaller capacity increments, such as cogeneration systems, would contribute to the improved financial health of the electric utility industry. Therefore, OTA undertook a comparison of the **capital costs** of the scenarios in table 61 with and without cogeneration. For the base case—utility development of 50,000, 100,000, and 150,000 MW of capacity without cogeneration—two sets of assumptions were used (see table 62). The first (Case A) uses coal-fired plants with scrubbers to meet all the baseload capacity requirements. The capital cost for baseload coal was set at $1,014/kW (1980 dollars), the same figure used in modeling commercial cogeneration opportunities (see ch. 5). In the second base case (Case B), 50 percent of the baseload capacity was assumed to be coal-fired (at $1,01 4/kW) and the other 50 percent assumed to be nuclear powered (at $1,400/-kW, the average cost, including interest during construction, for those plants that came on-line in 1979-80) (30). In both base cases, peaking

Table 61.—Scenarios for Cogeneration Implementation

	50,000 MW					100,000 MW					150,000 MW				
	Steam oil	Steam gas	CT oil	CT gas	Total	Steam oil	Steam gee	CT oit	CT gas	Total	Steam 0il	Steam gas	CT Oil	CT gas	Total
ECAR	1,190	60	21	–	1,271	2,170	120	360	115	2,765	2,66S	157	1,478	306	4,629
ERCOT	–	12,400	1	–	12,401	–	23,260	10	150	23,420	–	31,010	40	398	31,448
MAAC		3,350	– 72	–	3,422	0,300	—	1,300		7,625	8,366	–	5,054	68	13,510
MAIN	1,210	200	18	–	1,428	2,275	390	320	125	3,110	3,033	514	1,245	329	5,121
MARCA	150	65	31	–	266	285	160	565	10	1,020	376	213	2,196	21	2,806
NPCC	7,210	10	47	—	7,267	13,526	20650		5	14,401	18,035	26	3,309		21,379
SERC	5,260	70	103	–	5,433	9,665	140	1,630	12	11,647	13,150	184	7,122	33	20,489
SPP	2,050	2,870	15	–	10,935	3,650	16,635	265	120	20,870	5,130	22,179	1,031	322	28,662
WSCCc	6,540	1,000	37	–	7,577	12,271	1,875	675	101	14,992	16,362	2,499	2,623	272	21,756
NERC–U.S. totals	26,960	22,695	345	–	50,000	50,542	42,600	6,195	663	100,OOO	67,362	56,782	24,098	1,758	150,000

CT - combustion turbine.

SOURCE: Office of Technology Assessment.

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Table 62.—Assumptions Used to Compare Capitai Costs

Technology type	Capital cost ($/kW)	Amount installed (MW) 50,000 MW		100,000 MW		150,000 MW	
		Case A	Case B	Case A	Case B	Case A	Case B
Baseload:							
Coal-fired	$1,014	45,655	22,827.5	93,142	46,571	124,144	62,072
Nuclear	1,400	0	22,827.5	0	46,571		62,072
Peakload	200	345	345	6,858	6,858	25,85:	25,856
		Case C	Case D	Case C	Case D	Case C	Case D
Diesels	$350-800	12,500	2,500	25,000	5,000	37,500	7,500
Gas turbines	320-900	12,500	7,500	25,000	15,000	37,500	*22,500*
Steam turbines	550-1,600	12,500	17,500	25,000	35,000	37,500	*52,500*
Combined cycle	$430-600	12.500	22.500	25.000	45.000	37.500	*67,500*

SOURCE: Office of Technology Assessment.

capacity was assumed to have a capital cost of $200/kW, the same figure used in the analysis in chapter 5.

Additional assumptions were needed to develop a capital cost comparison for meeting these capacity requirements **with** cogeneration. First, a mix of cogeneration technologies was established by selecting four mature systems–diesels, combustion turbines, steam turbines, and combined cycles–that represent a wide range of possible cogeneration applications, and then choosing two sets of penetration mixes for the four systems (see table 62). The first set (Case C) assumes that each of the technologies would contribute 25 percent of the capacity requirements. The second set (Case D) assumes that diesels would contribute 5 percent, combustion turbines 15 percent, steam turbines 35 percent, and combined cycles 45 percent. Capital costs for these four technologies vary widely depending on the size of the system, the fuel used, and the industrial or commercial application. Therefore, the full range of costs given in chapter 4 was used (see table ***18).***

Table 63 shows the capital investment needs for meeting the three capacity scenarios based on these assumptions. As can be seen in table 63, the assumptions used in estimating capital costs play a substantial role in determining the impact of substituting cogeneration for central station capacity. For example, in the 50,000 MW scenario, the central station capital requirements are as much as 90 percent higher than those for lower cost cogenerators, and up to 17 percent **lower** than those for higher cost cogenerators. Similarly, the mix of technologies affects the cost comparison, with Cases A and C having significantly lower capital requirements than Cases B and D. Equally wide ranges of results are shown for the 100,000 and 150,000 MW scenarios. However, if the **mean** of the cogenerator case costs is compared to the central station costs, the cogeneration cases require around 20 to 40 percent less capital than the central station cases.

Still greater uncertainties are introduced into the capital cost comparison if one factors in interest costs and construction duration. The cost of capital is heavily dependent on its source, including whether a project is financed through debt, equity, or internal funds; the source of debt or type of equity; and the interest rates and rate of return on equity. If one assumes that all factors except construction duration are equal, then the cost of capital obviously would be lower for smaller capacity increments such as cogeneration than for large central station plants. However, high interest rates mean that the shorter leadtime for cogenerators offers substantial short-term financing advantages over central station powerplants.

In addition to examining capital cost differences, OTA also estimated differences in O&M costs for equal amounts of central station and cogeneration capacity. The same capacity assumptions as in the capital cost estimates were used (see table 62), but additional assumptions had to be made with regard to O&M costs and capacity factors (see table 64). The results of the O&M cost comparison are shown in table 65. As can be seen in table 65, O&M costs show the

Table 63.—Comparison of Capitai Requirements (1980 dollars x 10°)

Without cogeneration				With cogeneration				Percent difference			
Technology	Case A	Case B	Percent difference A-B	Technology	Case C	Case D	Percent difference C-D	A-C	A-D	B-C	B-D
50,000 MW:				*50,000 MW*							
Baseload	46,294	54,106		Diesels	4,375-10,000	*875-2,000*					
Peakload	69	69		Gas turbines	4,000-11,250	*2,400-6,750*					
Total	46,363	54,175	15.5	Steam turbines	6,875-20,000	*9,625-28,000*					
				Combined cycle	5,375-10,000	*9,675-18,000*					
				Lowest total	20,625	*22,575*	*9*	*76.8*	*69.0*	*90.0*	*82.3*
				Highest total	51,250	*54,750*	*6.6*	–10.0	–16.6	5.5	–1.1
				Mean	35,938	38,663	7.3	25.3	18.1	40.5	33.4
100,000 MW:				100,000 MW:							
Baseload	94,446	112,422		Diesels	8,750-20,000	1,750-4,000					
Peakload	1,372	1,372		Gas turbines	8,000-22,500	4,600-13,500					
Total	95,818	113,794	17.2	Steam turbines	13,750-40,000	19,250-56,000					
				Combined cycle	10,750-20,000	19,350-36,000					
				Lowest total	41,250	45,150	9	79.6	71.9	93.6	66.4
				Highest total	102,500	109,500	6.6	–6.7	–13.3	10.4	3.8
				Mean	71,875	77,325	7.3	28.6	21.4	45.2	38.2
150,000 Mw:				150,000 MW:							
Baseload	125,680	149,642		Diesels	13,125-30,000	2,625-6,000					
Peakload	5,171	5,171		Gas turbines	12,000-33,750	7,200-20,250					
Total	131,051	155,013	16.8	Steam turbines	20,62540,000	28,875-64,000					
				Combined cycle	16,125-30,000	29,025-54,000					
				Lowest total	61,875	67,725		71.7	63.7	65.9	78.4
				Highest total	153,750	164,250	6°6	–15.9	–22.5	0.8	–5.8
				Mean	107.813	115.988	7.3	19.5	12.2	35.9	28.8

aA negative percent difference means that cogeneratlon coats are higher, and a positive percent difference Indlcates that central station costs are higher.

SOURCE: Office of Technology Assessment.

Table 64.—Assumptions Used in Estimating Operating and Maintenance Costs

Type of equipment	Size (MW)	Capacity factor	Annual fixed O&M cost ($/kw)	Variable O&M cost (mills/kWh)	Consumable O&M cost (mills/kWh)
Central station:					
Coal steam	1,000	75%	12.9	0.90	2.6
Light water reactor	1,000	75%	3.1	1.50	—
Combustion turbine	75	9%	0.275	2.925	—
Cogeneration:					
Steam turbine	0.5-100	90%/45%	1.6-11.5	3.0-8.8	—
Gas turbine	0.1-100	90%/45%	0.29-0.34	2.5-3.0	—
Combined cycle	4-100	90%/45%	5.0-5.5	3.0-5.1	
Diesel	0.075-30	90%/45%	6.0-8.0	5.0-10.0	–

SOURCE: Off Ice of Technology Assessment.

same wide variation as capital costs, depending on the mix of equipment types, sizes, and capacity factors. In general, however, the figures in table 65 suggest that O&M costs for cogeneration will be **lower** than those for central station capacity when the cogenerators are larger units suitable for industrial sites (i.e., steam turbines, combined cycles), or when they are operating at a lower capacity factor. Conversely, small cogenerators **with a higher proportion of diesels and gas turbines, and those operating at a higher capacity** factor, tend to have **higher** O&M costs than central station capacity.

The labor requirements for construction and for O&M of equivalent amounts of central station and cogeneration capacity also were compared. This was extremely difficult due to a lack of consistent data. For example, estimated construction work-hour requirements by craft and **region are** available for central station capacity, but not for cogeneration. On the other hand, construction

Table 65.—Comparison of operating and Maintenance Costs (1978 dollars x 1O[a])

Without Cogeneration				With cogeneration							Percent differences							
Equipment	Case A	Case B	Percent difference A-B	Equipment	Case C90	Case D90	Percent difference C90-D90	Case C45	Case D45	Percent difference C45-D45	A-C90	A-D90	B-C90	B-D90	A-C45	A-D45	B-C45	B-D45
50,000 MW:				50,000 MW:														
Baseload	16.388	11.151		Diesels	5.67&10.655	1.136-2.171		3.214-5.83	0.643-1.IW									
Peakload	0.009	0.009		Gas turbines . . .	2.5-3.0	1.5-1.8		1.266-1.521	0.761-0.912									
Total	16.397	11.180	36.0	Steam turbines .	3.156-10 .11	4.419-14.154		1.6705.774	2.350-8.063									
				Combined cycle	3.58-5.714	6.447-10.285		2.103-3.2	3.786-5.761									
				Lowest total .	14.914	13.502	9.9	8.263	7.54	9.2	9.5	19.4	–28.8	–19.0	*88.0*	*74.0*	*29.8*	*36.7*
				Highest total .	29.679	28.410	4.4	16.425	15.942	3.0	–57.7	–53.6	–90.7	–87.2	*–0.2*	*2.8*	*–36.2*	*–35.3*
				Mean.	22.297	20.958	6.2	12.344	11.741	5.0	–30.5	–24.4	–88.6	–61.0	*28.2*	33.1	–10.7	–5.1
100,000 Mw:				100,000 MW:														
Baseload	33.434	22.750		Diesels	11.36-21 .71	2.27434		6.43-11.88	1.266-2.37									
Peakload	0.179	0.179		Gas turbines . . .	5.0-6.0	3.0-3.6		2.54-3.04	1.522-1.825									
Total	33.613	22.929	37.8	Steam turbines .	6.313-20.22	8.636.28.31		3.36-11.55	4.7-16.185									
				Combined cycle	7.163-11.425	12.89-20.57		4.2-6.4	7.57-11.52									
				Lowest total .	29.838	28.996	9.9	16.530	15.078	9.2	11.9	21.8	–26.2	–16.3	88.1	76.1	32.4	41.3
				Highest total .	59.355	58.820	4.4	32.850	31.860	3.0	–55.4	–51.3	–88.5	–85.0	2.3	5.3	–35.6	–32.7
				Mean.	44.596	41.909	6.2	24.690	23.479	5.0	–28.1	–22.0	–64.2	–58.5	30.6	35.5	–7.4	–2.4
150,000 MW:				*150,000 MW:*														
Baseload	44.582	30.322		Diesels	17.03-32.6	3.414.513		9.64-17.78	1.93-3.58									
Peakload	0.676	0.676		Gas turbines . . .	7.5-9.0	4.5-5.4		3.6-4.%	2.28-2.74									
Total	45.236	30.996	37.4	Steam turbines .	9.47-30.33	13.26-42.46		5.035-17.32	7.05-24.25									
				Combined cycle	10.7$17.14	19.34-30.85		6.31-9.6	11.36-17.28									
				Lowest total .	44.750	40.510	9.9	24.785	22.620	9.2	1.1	11.0	–36.3	–28.6	58.4	88.7	22.3	31.3
				Highest total .	89.070	85.223	4.4	49.260	47.630	3.0	–85.3	–61.3	–96.7	–93.3	–8.5	–5.6	–45.5	–42.7
				Mean.	66.910	62.887	6.2	37.023	35.225	5.0	–36.6	–32.6	–73.4	–67.9	20.0	24.9	–17.7	–12.8

aA negative percent difference means that cogeneratlon costs are higher, and a positive percent difference indicates that central~ station costs are higher.

SOURCE: Office of Technology Assessment.

labor costs are available for cogenerators, but usually are not broken out in surveys of central station installation costs. Moreover, labor requirements and costs for central station capacity vary widely by region and type and size of capacity.

However, in order to derive broad estimates for comparison purposes, the available data were applied to the three scenarios described above based on the capital and O&M cost estimates in tables 63 and 65. To estimate cogeneration construction labor requirements in work-hours, OTA used existing estimates of labor costs and divided by the 1979 average cost per work-hour for construction labor. The results were then compared to existing estimates of work-hour requirements for central station powerplants (see table 66).

As with the cost estimates in tables 63 and 65, the **construction labor requirements** in table 66 vary widely due to the wide range in the underlying assumptions. For example, for the 50,000 MW scenario, cogeneration is shown as requiring from 40 percent fewer to as much as 70 percent more work-hours than central station plants, depending on the size, type, and location of the central station capacity, and the size and type of cogenerators. Similar wide ranges are shown for the ***100,000*** and 150,000 MW scenarios. In general, construction labor needs for cogeneration are **higher** than those for an eqivalent amount of central station capacity when small-to medium-sized cogeneration units are installed, and lower when large cogenerators are used.

Although it is not possible to project actual construction labor needs without additional information on the size and type of cogeneration capacity to be used, it is possible to qualitatively compare the types of jobs that might result. Powerplant construction labor may be broken down into approximately 15 different craft requirements (see table 67). Not all of the skills listed in table 67 would be needed for cogeneration installation, nor would the proportion of each craft be similar (although actual craft needs for installing cogeneration have not been published).

The location and duration of labor needs also will be quite different for cogeneration and central powerplants. Central station capacity construction is likely to occur in larger capacity increments at relatively isolated rural sites, and to

Table 66.–Comparison of Construction Labor Requirements (WH x 10^6)

Without cogeneration				With cogeneration				Percent dlfference[a]			
Technology	Case A	Case B	Percent difference A-B	Technology	case c	Case D	Percent difference C-D	A-C	A-D	B-C	B-D
50,000 MW:				**50,000 MW**							
Baseload.	389.8-452.0	*497.6-646.0*		Diesels	72.92-186.67	14.58.33.33					
Peakload.	0.88-1.24	*0.88-1.24*		Gee turbines	46.15-129.81	27.69-77.89					
Lowest total. . .	370.88	*498.48*	*29.4*	Steam turbines	132.21484.62	185.05-537.96					
Highest total . .	453.24	*847.24*	*35.3*	Combined cycle , . . .	82.69-153.85	148.85-276.95					
Mean	411.98	*572.88*	*32.7*	Lowest total	333.97	378.17	11.9	10.4	1.5	39.5	28.0
				Highest total	834.96	926.13	*10.4*	–59.3	–68,6	–25.3	–35.5
				Mean.	584.48	661.15	*10.8*	-34.6	–45.0	–2.0	–12.8
100,000 MW:				**100,000 MW:**							
Baseload.	754.45-922.1	1,015 .2-1,318.0		Dlesels	145.84-333 .34	29.18-86.67					
Peakload.	17.59-24.63	17.59-24.63		Gas turbines	92.30259.82	55.38-155.78					
Lowest total . .	772.04	1,032.79	*28.9*	Steam turbines	264.42-789.24	370.1-1,075.92					
Highest total .	946.73	1,342.63	*34.6*	Combined cycle	185.38-307.70	297.7-553.9					
Mean	859.39	1,187.7	*32.1*	Lowest total	887.94	752.34	11.9	14.5	2.6	42.9	31.4
				Highest total	1,689.90	1,852,3	10.4	–55.3	–64.7	–21.7	–31.9
				Mean	1,188.9	1,302.3	10.8	–30.5	–41.0	1.6	–9.2
150,000 MW:				**150,000 MW:**							
Baseload, ...	1)005 .6-1,229.0	1,353 .2-1,758.5		Diesels	218.76-500.01	43.74-100.00					
Peakload.	88.3-92.8	66.3-92.8		Gas turbines	138.45389.43	83.07-233.67					
Lowest total. .	1,071.9	1,419.5	*27.9*	Steam turbines	396.63-1,153.86	555.15-1,613.88					
Highest total	1,321.8	1,849.3	*33.3*	Combined cycle	248.07-481 .55	446.55-830.85					
Mean	1,196.9	1,634.4	*30.9*	Lowest total	1,001.9	1,128.5	11,9	6.8	–5.1	34.5	22.8
				Highest total	2,504.9	*2,778.4*	10.4	-61.8	–71.1	-30.1	-40.2
				Mean	1,753.4	*1,953.5*	10.8	-37.7	–48.0	–7.0	–17.8

a A negative percent difference means that cogeneration labor requirements are higher, and a posltlve percent difference Indicates that central station labor requirements are higher.

SOURCE: Office of Technology Assessment.

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Table 67.—Craft Requirements for Central Station Powerplant Construction

	Percent of total construction labor	
Craft	Nuclear	Fossil
Asbestos workers/insulation. .	1.6	3.5
Boilermakers	3.3	15.0
Bricklayers/stone masons	0.4	0.5
Carpenters	11.1	8.5
Cement/concrete finishers . . .	1.4	1.1
Electricians	16.3	14.3
Ironworkers	7.7	9.0
Laborers	15.0	11.8
Millwrights	2.4	2.9
Operating engineers.	6.2	7.6
Painters	2.5	1.5
Pipefitters	26.5	18.6
Sheet metalworkers	1.5	2.0
Truck drivers		3.2
Other workers	0.5	0.4

SOURCE: U.S. Department of Energy, Off Ice of Energy Research; and U.S. Department of Labor, Employment Standards Administration, *Projections of Cost Duratlon, and On-Site Manual Labor Requirements for Constructing Electric Generating Plants, 197~19&3 DOE/IFf-O 057 and DOUCLDS/PP2,* September 1979.

Table 68.—Estimated Operating and Maintenance Labor

Capacity type	Size (MW)	WH/MWh
Central station.[a]		
Nuclear	1,000-2,000	0.0389-0.0761
Coal	1,000-2,000	0.0462-0.0793
Cogeneration:		
Diesel[b]	*0.24*	27.8-55.6
	0.7	9.5-19.0
	1.135	5.9-11.7
	2.84	2.1-4.7
Gas turbine[b]	0.5	12.6-26.7
	10.0	0.63-1.3
	50.0	0.13-0.27
Steam turbine[c]	15-30	1.114-1.968
	45-70	0.378-0.464
	140-190	0.136-0.159

[a]Derived from actual operating experience of plants responding to *Electrical World's* 21st Steam Station Cost Survey (Nov. 15, 1979), assuming that each employee works an 8 hour shift 260 days/year.
[b]Derived from Acres American, Inc., *A Report on Cogeneration Plant Costs and Performance* (report prepared for The Cogeneration Task Force of the New York Power Pool, February 1978). The range given is for a 90 percent and a 45 percent capacity factor.
[c]Based on actual operating experience of cogenerators reported in Electric Power Research Institute, *Industrial Cogeneration Case Studies,* EPRI EM-1531, September 1980.

SOURCE: Office of Technology Assessment.

entail large influxes of workers (either temporary residents or commuters) for several years. **The social and economic disruption that can result from powerplant construction is well** documented in the literature. Cogenerators, on the other hand, are more likely to be installed at commercial or industrial sites, usually located near population centers. Moreover, because cogeneration would be installed in smaller capacity increments, fewer workers would be required for each installation. Although the installation jobs would be of much shorter duration, they would occur more frequently, providing a steadier re**gional employment profile. Thus, the potential** for adverse socioeconomic impacts **would be much lower with cogeneration.**

Estimated requirements for O&M **labor** are compared in table 68. These were not translated into the three scenarios due to the large number of uncertainties and gaps in the data. However, it is clear from table 68 that the labor requirements for cogeneration per megawatthour of output will be greater than those for central station capacity. How much greater will depend on the size, type, and operating characteristics of the cogenerator. The crafts involved (engineering, fuel handling, general labor) are likely to be similar for cogeneration and coal-fired powerplants, but, as with construction labor, the location of the jobs will be very different.

The above comparisons of capital and O&M costs and labor requirements for equivalent amounts of central station and cogeneration capacity indicate that cogeneration has the potential to reduce the cost of supplying electric power while increasing the number of jobs associated with electricity generation. * However, depending on the size and type of cogenerators deployed, it could have the opposite effect-higher capital costs and/or lower labor requirements. That is, the financial and employment effects of cogeneration are highly correlated with economies of scale. Based on the mean values, however, it is more likely that cogeneration costs will be lower and labor needs higher than those for central station powerplants.

Utility Planning and Regulation

Where utilities face financial, fuel availability, or other constraints on capacity additions, or where they are heavily dependent on oil-fired capacity that cannot be converted to coal, co-

***Note that this seemingly anomalous result is possible only if cogeneration installation and operation/maintenance require less skilled (and thus lower paid) labor than central station plants, which is likely to be the case.**

generation can benefit utility finance, planning, and operations. If utilities own cogeneration capacity, the potentially lower capital costs—together with the lower cost of capital that results from short construction leadtimes and smaller capacity increments—will mean lower shortrun costs to be passed on to their customers. Other financial characteristics also would be likely to improve, including utilities' ability to finance projects internally and the amount of Allowance for Funds Used During Construction (AFUDC) (or Construction Work In Progress–CWIP) and deferred taxes they carry on their books. All of these **factors would tend to slow the rate of** growth **in retail electricity rates as well as make utilities** more attractive to investors.

The short construction leadtimes and small unit size of cogenerators also can have important benefits for utility planning and operations. If the demand for electricity increases more rapidly than utility planners project, smaller plants can be brought on-line more quickly (i.e., a 2- to 3-year leadtime for cogenerators compared to an 8-to 10-year leadtime for baseload coal plants and 10 to 12 years for nuclear plants). Similarly, if demand grows more slowly than expected, smaller capacity increments can be deferred more easily and inexpensively than large powerplants for which planning and construction must begin years before the power is projected to be needed. In addition, small unit sizes will have lower outage costs (less unserved energy) than larger units, assuming that both sizes present approximately the same degree of reliability.

The potential for all of these benefits would be enhanced if utilities were allowed to own a 100 percent interest in cogeneration capacity and still receive unregulated avoided cost rates under PURPA. That is, their qualifying cogeneration capacity would be unregulated and the cogenerated power could be valued at the avoided cost rather than the average cost. Thus, the utility could earn a higher rate of return on it than on their regulated generating capacity. This higher return would compensate them more fully for the perceived risks of investment in "unconventional" technologies with relatively uncertain operating characteristics, but probably would still be lower than the rate of return required by industrial or commercial owners. Similarly, the higher return would increase the cost that would have to be passed on to customers, but that cost might still be lower than under nonutility ownership.

Utilities with long-term contracts for purchases of cogenerated power could still use the smaller capacity increments to reduce the downside risk of sudden unexpected changes in demand growth. outage costs also would probably remain relatively equal under either form of ownership, although utilities may consider cogenerators they own to be more reliable due to perceived or actual differences in dispatchability and other factors affecting reliability. But these considerations are tempered by the probability that cogeneration would supply more electricity to the grid under utility ownership. Utilities typically require a lower rate of return—even when unregulated—than private investors, and financially healthy utilities often have access to lower cost capital. Thus, cogeneration investments maybe economic for utilities when they would not be for users or third parties. Furthermore, except where avoided costs are very high, utilities would be more likely to invest in cogeneration systems with a high ratio of electricity-to-steam production (E/S ratio).

For nonutility ownership, the benefits from cogeneration's potentially lower power production costs would accrue to the cogenerator rather than to the utility or its customers. Under the original FERC rules implementing PURPA, the cogenerator would be paid for power supplied to the grid based on the utility's avoided cost of alternative energy (or marginal cost), rather than on the average energy cost (see ch. 3). This higher cost would be passed on to the utility's noncogenerating customers. Moreover, the utility would have administrative and other expenses related to capacity that were not included in its rate base and on which it would not earn a rate of return.

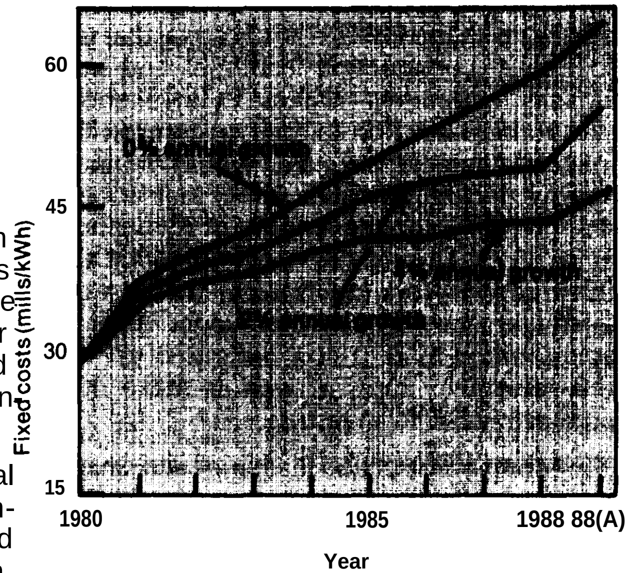
Finally, utilities may be subject to planning and financial risks from the increased competition posed by nonutility-owned cogenerators. When competition takes away utility customers, the joint or common costs get a reduced revenue contribution. This reduction in fixed cost coverage either endangers service to other customers or imposes a greater share of the cost burden on them. This phenomenon is not unique to electric power. It has occurred in the transportation industry, most dramatically with the competition between trucking and railroads, and the same problems currently are being faced by the telecommunications industry. It is essentially the same as the issue of loss exposure raised by Con-Ed in the New York Public Service Commission hearings on cogeneration (see ch. 3). Remedies for such problems, insofar as they exist, must be found in the rate structure of the utility, or through changes in Federal policy that would equalize utilities' competitive position in cogeneration markets.

The following material analyzes the potential effects of competition on two utilities: Commonwealth Edison (CWE), which is committed to major central station capacity construction, and Pacific Gas & Electric (PG&E), which is constrained from adding large amounts of new central station capacity and has been ordered by the California Public Utilities Commission to aggressively seek cogeneration capacity. Background information on the implementation of PURPA in these utilities' service areas may be found in chapter 3.

Current cost conditions in the electric power industry can give rise to reduced fixed cost coverage. These are illustrated for CWE in figure 61, which shows the average fixed cost portion of CWE revenue requirements, based on their current construction plans, for growth rates of 4, 2, and O percent (CWE projects 4 percent load growth). Any load growth lower than 4 percent–whether it is due to competition from onsite generation or from conservation-will result in sales below CWE expectations and thus a rising burden of fixed costs for remaining customers. As shown in figure 61, the larger the shortfall in sales, the faster the fixed cost burden rises.

Turning to the California context, it is more readily apparent that PURPA payments to cogenerators can lead directly to reduced fixed cost coverage. PURPA payments for capacity are fixed costs from the ratepayers' point of view, even if their basis in value comes from fuel savings.

Figure 61.—CWE Fixed Cost Structure as a Function of Sales Growth



SOURCE: Edward Kahn and Michael Merritt, *Dispersed Electricity Generation: Planning and Regulation* (contractor report to OTA, February 1981).

When a utility contracts to purchase energy from a private party, on an avoided cost basis, the PURPA payments should drop with decreasing demand. However, this may not be the case, or at least not to any significant degree. To demonstrate this proposition, the cost structure of PG&E is illustrated in table 69.

The differences between the base case and the PURPA case in table 69 are due to two factors. First, there is more than twice as much cogeneration in the PURPA case compared to the base case (940 MW v. 2,000 MW). The larger amount of cogeneration represents a fulfillment of the goal set for PG&E by the California public Utilities Commission. The second difference is that the

Table 69.—Pacific Gas & Electric Cost Structure Adjusted for PURPA, 1990

	Base case	PURPA case
Fixed costs	$5.31 x 10^9	$8.58 x 10^9
Fuel	$5.22 x 10^9	$3.87 X 10^9
Sales to noncogenerators	87.4 X 10 kWh	80.8 X 10^9 kWh
Fixed cost/kWh to noncogenerators	80.8 mills	81.4 mills

SOURCE: Edward Kahn, and Michael Merritt, *Dispersed Electricity Generation: Planning and Regulation* (contractor reporl to the Office of Technology Assessment, 1981).

base case assumes utility ownership while the PURPA case assumes private ownership.

Table 69 shows the same qualitative phenomenon as figure 61—a rising burden of fixed or common costs to be borne by the nongenerating customers remaining on the utility system. In the PG&E case, the shift is clearly due to the effects of cogeneration. Moreover, a significant part of the increase in fixed cost comes from PURPA incentives under the simultaneous purchase and sale provision—estimated at roughly $445 million, assuming that cogenerators will pay rates for their own use that are roughly 70 percent of the average price (18). The estimate may, of course, be too high. If it is high, the net fixed costs would be less and the risk less extreme. However, the simultaneous purchase and sale incentive is only about one-third of the fixed cost differential (445/1,270) in the two cases. Therefore, even a change in the rate structure to reduce that incentive would not by itself eliminate the problem. Customers remaining on the utility system would have fewer incentives to conserve electricity at this point because reduced sales would only increase the fixed cost burden (29).

Thus, the increasing burden of fixed costs can result from either excess capacity (CWE) or competition (PG&E). Of the two distinct routes to the high fixed cost situation, it is likely that the competition risk may be smaller than the excess capacity risk. The reason for this is the potential escalation in fuel costs. The calculations in table 69 show fuel costs ranging from about 50 percent of total cost in the base case to about 37 percent of total cost in the PURPA case. The fuel cost fraction would rise if fuel cost escalated faster than assumed (roughly 10 percent nominal annual rate). Although no one can predict future oil prices (the dominant fuel in California), the tendency in the past has been to underpredict price increases (29).

On the other hand, the excess capacity risk results in part from the "lumpiness" of investment in baseload facilities. New central station plants come in large unit sizes and require long construction and licensing times. Further, accurate demand forecasting is difficult, and the tendency in the past has been to overestimate the future size of the electricity market. However, demand growth is more sensitive to price increases than pre-1 973 behavior seemed to indicate and large baseload projects are difficult to adjust to reduced growth. Powerplant construction can be deferred (which means extra carrying cost) or canceled (which means losses). Thus, once large projects are initiated there is a tendency to continue them regardless of changing circumstances.

Therefore, where construction commitments are large (as in the CWE case), the balance of economic and institutional forces points toward a greater risk from excess capacity than from competition. At the present time, however, the risks from cogeneration competition are more potential than real due to its low market penetration. One way utilities can deal with possible future competitive threats is by trying to capture the new markets with their own investment.

Other Economic and Social Impacts

OTA's analysis focused on the economic and social impacts of cogeneration on electric utilities and their customers. However, cogeneration may also have important socioeconomic implications in other sectors, such as business development patterns for fuel and technology suppliers and capital markets, and the role of policy/politics in energy supply. A detailed assessment of these issues is beyond the scope of this report, but some general considerations are outlined below as a framework for future analysis.

PURPA'S partial deregulation of entry into the electricity generation market has received a lot of attention for the opportunities it presents for new and small businesses, and for the changes it may bring to existing economic sectors. For example, the primary sources of fuel for cogenerators in the near term are not expected to be different from the fuel sources for electric utilities (oil, **gas,** and coal). However, as advanced cogeneration technologies with greater fuel flexibility emerge, new opportunities should arise for suppliers of alternate fuels such as municipal **solid waste (MSW), biomass, and synthetic liquids and gases. In some cases, these markets will** be captured by existing large energy companies seek-

Photo credit: Environmental Protection Agency

Advanced cogeneration technologies with greater fuel flexibility may be able to burn municipal solid waste, contributing to the solution of waste disposal problems and providing a new source of revenue for disposal collection agencies

ing diversification opportunities. But other markets may be served by local governments or private entrepreneurs (e.g., MSW), or supplied onsite (biomass), or captured by utilities or cogenerators themselves. For instance, one promising scheme for alternate-fueled cogeneration uses a centrally located gasifier that converts coal, biomass, petroleum coke (from refineries), or other nonpremium fuels to a low- or medium-Btu gas for distribution to cogenerators within a limited radius. The gasifier could be owned jointly by the cogenerators (e.g., in an industrial park) or by the local utility as a means of diversifying its energy supply business. A central gasification/remote cogeneration scheme proposed by Arkansas Power & Light is described in detail in chapter 5. Such a scheme would enable cogenerators who cannot use nonpremium fuels (e.g., due to environmental, economic, or site limitations) to centralize the costs of fuel conversion and distribution. Thus, economic and policy considerations that discourage the use of oil and gas in cogeneration also may help to create new business opportunities for a wide range of fuel suppliers. In many cases these opportunities will go to local distribution companies, as opposed to the large producers or distributors that supply central station powerplants.

Markets for technologies also could change as a result of the widespread use of cogeneration. Electric utilities or their construction contractors generally interact directly with the major manufacturers of powerplant equipment. Cogenerators, on the other hand, will be more likely to purchase a total system from vendors acting as middlemen between manufacturers and purchasers. Such vendors will be able to offer a wider range of "package" systems than a single manufacturer, and to tailor the package more closely to a user's specific needs. Moreover, whereas utilities generally perform their own maintenance, cogeneration vendors may evolve as total service companies that offer repair and maintenance as part of the sales contract. The potential role for such service companies in spreading the burden of maintenance costs and labor requirements contributes to the uncertainty (discussed earlier in this chapter) in assessing these factors. Alternatively, if utilities own cogenerators, they may tend to continue to deal with the major manufacturers with which they are familiar, and to provide their own maintenance.

Similar changes might appear in capital markets with widespread investment in cogeneration. The small unit size of cogenerators will mean smaller but more frequent investments in generating capacity increments. If utilities are investing, then their capitalization is likely to shift away from long-term debt and equity to short-term debtor retained earnings. Alternatively, utilities may establish innovative low-interest loan programs for cogenerators. Third-party investors may play a major role due to the tax incentives introduced by the Economic Recovery Tax Act of 1981. Or potential cogenerators may shift their investment priorities from process equipment to cogeneration. As a result of all these types of owners, new capital markets for energy projects will be introduced. Traditional lending institutions such as banks could become financiers for energy projects. Investment firms will have a new option for sheltering their clients' income. A wide range of traditional financiers may establish leasing subsidiaries.

The potential impacts on fuel, technology, and capital markets outlined above will themselves have far-reaching effects. For example, concern is frequently expressed about the anticompetitive aspects of utility investment in cogeneration. It is argued that utilities may favor their own subsidiaries in contracting for cogenerated power, or favor one or two manufacturers or vendors of cogeneration systems, and thus foreclose small business opportunities and/or stifle the development of innovative technologies. Similarly, utility loan programs have raised questions about competition in the banking industry, where market entry traditionally has been regulated. Although these concerns may be real, closing these markets to utilities could also stifle the development of cogeneration capacity, and it may be more sensible to resolve any questions about the competitive effects of utility investment through carefully drafted legislation and regulations, and through established legal and administrative remedies.

The introduction of new fuel supply configurations could have significant impacts on other fuel users as well as on land use patterns and other environmental factors. If oil- or gas-fired cogeneration achieved a significant market penetration, changes could occur in the way these fuels are allocated among noncogenerating residential, commercial, and industrial customers. Centralized fuel conversion systems such as gasifiers would require new dedicated distribution systems, and would strongly influence the location of new cogenerating industries. Where fuel conversion is not centralized, fuel delivery and storage may pose substantial problems, especially in urban areas. If the cogeneration site is not able to accommodate large fuel storage facilities (e.g., 30 days' supply), then frequent deliveries could involve noise and/or air pollution as well as traffic congestion. As with the concerns about the anticompetitive aspects of utility ownership of cogenerators, these potential land use problems are probably best solved through careful design and siting of cogenerators and rational local planning, rather than through general disincentives to cogeneration.

Centralization and Decentralization of Electricity Generation

In the two decades following World War II, the electric power industry operated under a declining production cost curve even during periods of general increases in the cost of fuels and the overall consumer price index. The primary contributor to these declining costs was the capture of significant economies of scale that allowed larger powerplants to use fuel more efficiently (see ch. 3). At the same time, obvious cost savings became associated with the location of multiple units on single sites, and planning responsibilities, decisionmaking authority, and capital assets became concentrated in a rapidly diminishing number of institutions—primarily investor-owned utilities (32). The resulting combination of large powerplants concentrated at a central location and under the authority of a limited number of large organizations has become known as the centralization of the utility industry.

When engineering economies of scale were no longer able to offset other costs for larger powerplants, and the electric power industry's declining cost curve disappeared in the late 1960's, the value of such centralization became increasingly debated. Questions have been raised about the role of centralization in the adverse environmental impacts of large powerplants, in utilities' financial deterioration, and in more qualitative concerns such as individual's feelings that they have lost some control over important aspects of their lives and livelihoods. As a result, it is frequently suggested that the electric power industry should be restructured in favor of a decentralized system based on small-scale technologies located at or near the point of use and subject to local or individual control. This position is advocated by a wide range of groups with varying goals, but the central features of the argument generally are considered to be embodied in the writings of Amory Lovins and colleagues on the "soft energy path" (31).

This section reviews the context of the debate over centralized and decentralized electric energy systems, then analyzes the role that cogeneration might play within that debate. *

Technology and Values

One of the critical features of the current energy policy debate is the lack of consensus on both the facts and the values surrounding energy policy. Thus, there are radically different perceptions about the actual nature of the "energy problem" as well as disagreements about the role energy plays in structuring social organization. One of the most pervasive of these disputes is over the centralization or decentralization of electric power production.

The point of view that argues for "decentralization" is embodied in a number of separate movements (e.g., appropriate technology, environmentalist, antinuclear), each of which has its own criteria for evaluating energy technologies. But they all tend to converge with regard to proposals for small-scale renewable energy technologies, as embodied in the "soft-path" future first described by Lovins.

The three primary components of Lovins' soft energy path are:

- prompt commitment to maximizing end-use efficiency;
- rapid development and deployment of small-scale renewable-fueled technologies whose energy quality closely matches the required service; and
- special transitional fossil fuel technologies.

The first component would minimize the energy input into a given end-use function. The second would accelerate reliance on renewable fuels and on energy technologies that contribute to self-reliance, and the third would "tide us over" until the system adjustments anticipated by the first two can be made. Because of Lovins' overriding concern with thermodynamic efficiency, cogeneration—primarily industrial cogeneration using coal-fired fluidized bed combustion systems—is viewed as a major contributor to the transitional fossil fuel technologies.

Lovins' writings have played a major role in winning a place for alternative technologies in the energy policy debate. However, as in other energy policy areas, the facts and values surrounding soft energy paths are subject to debate. With respect to the facts, the uncertainties in capital and operating costs and in output characteristics are especially important. In regard to the values, there is disagreement not only between soft and hard path advocates, but also between different segments of the alternative energy movement.

For example, Lovins only applies soft energy technologies at the margin; he does not advocate the early replacement of existing central station

*Much of the following discussion is from Hoberg (26).

powerplants and their accompanying transmission and distribution networks. Other "appropriate" technology advocates focus on stand-alone applications that are totally incompatible with the existing electricity supply system (e.g., windmills or photovoltaics coupled with battery storage). Moreover, there is no real consensus among soft path advocates as to which values should predominate in such technological decisions. Some place a great deal of emphasis on fostering decentralization in order to gain control over the technologies that affect their lives, while others emphasize economic efficiency.

The debate about the role of cogeneration in energy policy typifies these fact and value disputes in several ways. It can be a small-scale technology located at the point of use, or larger systems can be centrally located and the energy products distributed among several co-owners or customers. Cogenerators can use coal or other alternate fuels as their primary energy source, but the most economic systems for some applications will rely on oil or gas in the near term (e.g., gas turbines, diesels). Cogeneration can present significant energy savings when compared to central station generation and separate thermal power production, but it also will be competing against conservation, coal, and renewable fuels on many electric systems, and its electric power output is less certain. Thus, whether cogeneration will be a favored technology to advocates of decentralized energy systems will depend heavily on the technology and the mode of deployment chosen.

Centralization and Decentralization

The concepts of centralization and decentralization are critical to an assessment of the social and institutional impacts of dispersed electricity generation, but are all too often left undefined. In this discussion, these terms will be used to describe a measure of the distribution of control, authority, or autonomy throughout a system (in this case the energy and social systems), where "control" refers to the ability to affect the behavior of others or of the system itself. A situation in which a single component controls all others and the system itself (e.g., a monopoly or monopsony) defines the centralized extreme, while at the decentralized extreme each individual is autonomous and therefore cannot change the system or its components (e.g., perfect competition). This concept of centralization is similar to that in organization and administration theory, where the concern is locating the decision making authority within an organization or institution. The concepts of centralization and decentralization of control are particularly important to the structure of organizations because mismatches between that structure and the task it is designed to accomplish can result in inefficiencies (7).

The centralization or decentralization of **control** should be distinguished from other concepts that focus on size or geographical concentration. While these factors may influence the degree of centralization, they do not define it. Similarly, it is useful to distinguish **technical** from **social** centralization. Thus, technical systems can be defined in terms of their dependence on one or a few components (e.g., central dispatch of an interconnected electric utility system) without necessarily implying an equal degree of authority over a related social system.

Centralization/Decentralization and Cogeneration

How cogeneration fits into this definition of centralization and decentralization will depend on its deployment and operating characteristics. Thus, the lower minimum efficient **scale** of cogeneration relative to conventional powerplants can contribute to decentralization because the smaller size and lower costs make the technology accessible to more people. On the other hand, cogenerators are more **complex** than traditional onsite thermal energy systems (e.g., boilers, furnaces), and they are likely to require new technical and managerial skills in industrial and commercial enterprises that own and operate them, or in utility companies that deploy them in their service areas. Whether a firm decides to train or acquire its own expertise or to rely on a vendor, utility, or other service company may determine that firm's perceptions of autonomy.

Similarly, the **resource/demand characteristics** of cogeneration, including the type of primary energy source and its concentration or density, the type of technology and its concentration, and the actual number of components in the resource, conversion, and demand categories will influence the degree of centralization. In general, decentralization might occur if the energy required within a given area is approximately equal to the energy available in that area. If energy must be imported, the system will be more vulnerable to external control and thus relatively centralized. Similarly, where the energy can be exported or distributed over a larger area, a relatively centralized dependence of dispersed users on a concentrated resource may result.

Finally, the amount of **political or social importance** associated with cogeneration will be a significant factor in determining centralization and decentralization of control. For example, PURPA encourages grid-connected cogeneration, offering economic incentives for operating characteristics (such as central dispatch) that increase utilities' control over the deployment and use of the technology.

Because all these characteristics will vary widely, it is clear that cogeneration cannot automatically be considered a decentralized technology that will lead to a decentralized social structure. Similarly, central station powerplants will not always lead to centralized social organization, although this has been the predominant trend in the electric power industry. Rather, it is possible to envision centralized technologies that contribute to a decentralized social or political system, as well as decentralized technologies leading to centralization of control. For example, Franklin Roosevelt saw centralized generation of electricity with transmission to outlying areas as the key to a decentralized society:

> Sheer inertia has caused us to neglect formulating a public policy that would promote the opportunity to take advantage of the flexibility of electricity; that would send it out wherever and whenever wanted at the lowest possible cost. We are continuing the forms of overcentralization of industry caused by the characteristics of the steam engine, long after we have had technically available a form of energy which should promote decentralization of industry (34).

The central theme underlying the possibility of such a **centralized energy system supplying a decentralized society** is the proposition that the most effective means of preserving diversity, flexibility, and freedom of choice in social structure is to ensure abundant supplies of energy at the lowest possible cost (termed the "cornucopia strategy"). The less scarce the fundamental energy input, the less influence energy would have on the structure of social organization. Cogeneration (and other alternative technologies) would be included in the cornucopia strategy to the extent that they pose economic advantages over conventional technologies. Moreover, a recent analysis suggests that cogeneration combined with the centralized electricity grid will contribute to decentralization in the economy(1). This analysis argues that the lack of significant scale effects associated with connection to a centralized grid will mean that large firms will not have competitive advantages over small firms in energy access (ignoring declining block rates or relative process efficiencies). Thus, diversity and decentralization of organizational structure in industry and business might be promoted.

The idea of centralized energy systems leading to decentralized social organization looks more to fragmentation of power among interest groups and various levels of government wherein freedom and flexibility in lifestyles are fostered and preserved, while the appropriate technology movement embodies a notion of decentralization that consists of a loosely coupled system of nearly autonomous and self-reliant communities. As such, the former view can accommodate a great deal of specialization and differentiation in societal function, at aggregate levels, that the latter fundamentally opposes.

On the other hand, it is also possible to envision a **decentralized energy system in a centralized political economy.** This might come about in two ways. One analysis considers the case where some combination of a deterioration in the economics of utility generated electricity and an enhanced competitive position of cogeneration systems brings about an industrywide movement towards cogeneration as the source of electric power and process heat/steam. Because there are economies of **scale** (in capital equipment, O&M, pollution control, etc.) inherent in cogeneration devices, the larger firms in a certain industry group will be able to produce energy more cheaply than the smaller firms, which would give the larger firms a competitive advantage, contributing to the elimination or absorption of smaller firms by the larger firms. The end result is centralization in industry (as measured by industrial concentration) (26).

A second view of this configuration-decentralized energy systems in the context of centralized control—also could result from policy considerations. In fact, some commentators have suggested that this is the most likely result:

> The most plausible vision of a renewable-energy future is one that offers less freedom and less true diversity, more centralization of decision, and more state (i.e., government) interference and corporate domination in our lives, than is the case in the present society in the United States . . . (37).

Clearly, this combination of decentralized energy and centralized social organization depends more on policy orientations than on any of the other factors that influence the degree of centralization/decentralization. Lovins terms this alternative a coercive one in that it is most likely to result from policies that mandate—rather than use market incentives for—a decentralized energy system (or the proverbial distinction between the carrot and the stick). Alternatively, such centralization could result from demands for control of the impacts of decentralized technologies in that it is easier to impose and enforce controls in a centralized manner (e.g., uniform Federal standards for system design at the point of manufacture) than it is to monitor and enforce such controls at myriad points of use. At the extreme, authoritative solutions may be seen as necessary to meet an industrial society's need for adequate and reliable supplies of energy, or to allocate losses in the event of an energy supply shortfall (37).

As has been seen above, cogeneration (and other dispersed generating systems) cannot necessarily be considered either a decentralized or a centralized energy system nor will they necessarily lead to either centralization or decentralization of social organization. Rather the degree of centralization/decentralization will depend on site specific, market, and policy factors such as the mode of operation, form of ownership, resulting profit and competitive aspects, and relative policy emphasis on their deployment.

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