MASTER

IMPACTS OF ENVIRONMENTAL AND UTILITY SITING LAWS
ON COMMUNITY ENERGY SYSTEMS

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ARGONNE NATIONAL LABORATORY

ENERGY AND ENVIRONMENTAL SYSTEMS

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IMPACTS OF ENVIRONMENTAL AND UTILITY SITING LAWS
ON COMMUNITY ENERGY SYSTEMS

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ABSTRACT

Community Energy Systems provide an interesting energy conservative alternative to the traditional trend of large, central, grid-connected power plant design. The small community energy system (generally smaller than 100 MW), provides for waste heat utilization and utility cogeneration significantly reducing a community's total energy demand.

Developers of Community Energy Systems, unfortunately, are faced with a complex of environmental and siting regulations, most of which are aimed at regulating the development and design of large power generating facilities. Aside from discouraging development of a potentially more economic and environmentally sound approach to power generation, air pollution regulations discriminate against these smaller systems. Compliance with the many federal, state, and local regulations often make small energy systems uneconomical. This project studies the emissions associated with Community Energy Systems and reviews the federal, state, and local laws which regulate their design.

APPROACH USED IN THE STUDY

- Isolate each ICES component relating environmental residuals with component size and design.
- Assemble federal, state, and local environmental regulations converting them to a common, comparable format.
- Apply ICES component emissions to federal, state, and local regulations.
- Identify control requirements to conform to emission limits.
- Review a selected number of local zoning ordinances, state siting laws, and federal legislation relating to ICES.
- Assess the constraints placed on ICES by federal and state siting laws and local zoning ordinances.

RESULTS

- ICES powered by I.C. engines and small combustion turbines:
 - Not likely to encounter environmental or siting problems.
- Small gas and oil-fired boilers, larger combustion turbines, small incinerators:
 - Not likely to encounter environmental problems but will be subject to EIS and rezoning hearings.
- Coal- and oil-fired boilers, less than 25 MW, large or "banked" turbines and municipal incinerators:
 - Will encounter state regulatory control (38 states) requiring ESP, baghouse, or scrubber. Substantial EIS and zoning review.

RESULTS (Contd.)

- Coal- and oil-fired boilers greater than 25 MW,
large incinerators and waste treatment plants:
 - Will encounter federal controls requiring ESP, baghouse, or scrubber control.

EXECUTIVE SUMMARY

Introduction

Developers of Community Energy Systems are faced with a complex of environmental and siting regulation which must be addressed in the initial stages of project planning. Aside from discouraging potential planners, compliance with the many federal, state and local regulations can be expensive, making otherwise cost beneficial projects uneconomical. A single ICES development, for example, could require a federal environmental impact statement, a state environmental impact statement, a national pollutant discharge elimination system (NPDES) permit, a state air pollution control permit, a local environmental permit to construct, a state utility commission environmental review, a new source review, a local zoning board review and site rezoning. At least two of the reviews just listed involve public hearings. Each of the reviews require that compliance with federal, state or local law be demonstrated depending upon the level of review. All reviews must be completed prior to commencement of construction. Time delays for project review and caused by environmental regulation can run from one to two years. Extremely controversial projects could require additional hearing, review and revision delay. Aside from the environmental and siting review process is the cost of regulatory compliance.

Small ICES using internal combustion engines or gas boilers are not expected to present environmental problems. Thus, costs associated with siting and environmental emissions will be small. Control costs are limited to noise isolation and project aesthetics. Costs for impact statements, zoning review and new source review are also expected to be minimal causing few serious impediments to developers. Larger ICES using coal boilers, incinerators, multiple gas turbines or large oil boilers face considerable resistance from existing federal, state and local regulation. Emission control costs dramatically increase as systems increase in size and alternative fuels such as coal or high sulfur oils are used. Sulfur oxide emissions present the greatest danger to the economic viability of ICES. Control costs associated with SO₂ scrubbing can be disproportionate for the amount of utilities generated.

The purpose of this study has been to identify specific federal, state and local laws likely to be encountered by ICES planners and developers.

Knowing the relationship between ICES size and design and federal, state and local law provides a clear definition of regulatory obstacles. The influence of regulations on ICES vary. While some laws or ordinances dictate the siting of an ICES, others influence the system design, size and economics. Larger ICES, for example, designed to meet environmental and siting restrictions, require the uneconomical use of stack gas scrubbing on the application of expensive fuels or uneconomical prime movers. If ICES are to be promoted as an energy conserving approach to utility generation, environmental and siting costs must be considered. Impediments caused by obsolete local zoning regulations and redundant environmental reviews can be minimized. Research can be directed toward providing an economical approach for environmentally acceptable fuel combustion and waste incineration.

Identification of Environmental Law Restricting ICES Development

Concern by citizens about the quality of their environment dates back to early zoning ordinances. By controlling the development and use of designated districts, local governments have been able to regulate, in a general sense, the activity or environment of a specifically zoned area. During the 1960s, when a national consciousness emerged for environmental quality, the federal government enacted legislation establishing funds and mechanisms for promulgating new environmental law. Federal activities in the Defense Department, Department of Interior, Department of Health, Education and Welfare, Environmental Protection Agency, Department of Transportation and Department of Energy have all established federal regulatory control over sources with emissions having the potential for environmental degradation. Some federal legislation established direct control over development of new sources while other federal legislation, such as the Coastal Zone Act provides for the establishment of state commissions responsible for regulatory control. A third type of federal legislation such as the Clean Air Act provides for state promulgation and enforcement of minimum federal standards. It additionally provides for assistance to the states to establish control programs and also necessitates the development of federal regulations. Since the late sixties, Congress has passed dozens of environmentally related bills. Three pieces of federal legislation stand out as having a potential impact on ICES development. They include the National Environmental Policy Act, the Clean Air Act and the Water Quality Control Act. As a result of federal environmental activities, ICES planners must look to and be aware of federal controls.

Traditionally, law enforcement has been a state responsibility. Environmental enforcement and control is not an exception. Despite considerable federal activity, states are responsible for attaining and maintaining acceptable environmental quality in their jurisdiction. State Implementation Plans (SIPs) were first published in 1972. These plans presented the regulations and strategies to be implemented in order to achieve and maintain national air quality standards. SIPs did not require states to have regulatory uniformity but rather indicated that two general requirements be attained:

1. State regulations could not be less stringent than federal laws.
2. The implementation of state laws must allow for the attainment and maintenance of national standards.

Because of a variation in the character of geographical and demographic considerations, state environmental regulations have only a limited similarity. While noise, siting, and water regulations are similar from state to state, air pollution emission regulations can change considerably.

In addition to state law, localities, specifically large metropolitan areas, have established local regulations. Metropolitan areas like Chicago or Pittsburgh have city or county agencies on both which enforce local regulations which must be equal to or stricter than state regulations governing emissions from any given specific source category.

As a result of local, state and national concern for environmental emissions, the ICES planner must interact with all levels of government. Often there is little relationship between federal, state and local laws governing emissions of a pollutant and a source. Such unconformities require ICES planners to review all laws when evaluating environmental impacts of ICES. Zoning regulation, while least mentioned, has perhaps the greatest influence on ICES siting and design. At the grass roots level, local zoning laws often specify noise and visible emission performance standards for all new sources. Through the vehicle of local zoning codes, communities can prohibit development of a source considered unacceptable for the zoned area in which it is to be located. Rezoning which is necessary for all ICES developments, requires public hearings, where local opinion can stop or significantly delay project development.

In order to assess the impact of environmental regulations on ICES, it has been necessary to assemble all pertinent federal regulations, state laws,

and local regulations which govern ICES emissions. Because of the vast number of local zoning codes, it has not been possible to assemble all zoning restrictions. Instead, typical zoning codes have been studied which reflect the majority of zoning impediments for ICES developers.

Determination of the Regulatory Impact of Federal, State and Local Environmental Laws

Given environmental regulation on three organizational/institutional levels and a variety of ICES designs and system sizes, it became necessary to systematically relate ICES designs to environmental and siting regulations.

While the number of possible ICES designs, concepts and configurations are too numerous to study as total systems, it was possible to subdivide ICES into component elements. Each element could then be assessed individually. When a specific ICES configuration is considered, the size and design of components can be identified. Regulatory impediments are then identified with each component in the system. The total of regulatory restrictions and control requirements for ICES components provide a reasonable estimate of the environmental/siting/control costs for the project.

The approach for determining regulatory impediments to ICES simplifies to identification of ICES components, estimation of environmental emissions by size and design of each component, collecting applicable regulations and relating emissions to emission limitations.

The last step of this procedure used a sieve approach. Emissions from ICES components were first passed through a sieve or filter representing federal regulation. Items passing the filter or sieve meet existing regulations and were passed to a sieve or filter representing state law. Components meeting state requirements were then passed through a sieve representing local regulations. When a given size component did not meet a regulatory test, a determination was made of the control equipment necessary to meet the emission limitation. The result of the process just described was the identification of components and the size of the components which would not meet federal, state or local law. Additionally, a determination was made of possible control techniques required to successfully meet those laws.

Identification of ICES Component Emissions

Energy system components can be described in a variety of ways. Because of the variation in potential designs, system components are first identified in general terms. Specific pieces of equipment then are categorized under each system component.

Major system components include the following subdivisions:

A. Prime Movers

1. Internal combustion engines
2. Steam generators
3. Combustion turbines
4. Other technologies

B. Ancillary Heat Sources/Energy Converters

1. Incinerators
2. Waste heat utilization/heat exchangers

C. Utility Generators

1. Electric generators/substations/transformers
2. Chilled-water generators
3. Hot-water generators
4. Hot- and cold-air generators

Prime movers, for example, are made up of a steam or compressed gas generator (a boiler or combustion chamber) and some sort of energy conversion device (a steam or gas turbine). Steam generators or boilers may be oil-, coal- or gas-fired. Additionally, each type of fuel can be subdivided into a variety of grades. Prime movers considered included coal, oil and gas boilers capable of generating 10 MW to 100 MW of electrical energy. Fuels included northwestern, central, northern Appalachian, central Appalachian and southwestern coal, residual and distillate oils with sulfur contents of .01%, .1%, .5%, 1.0% and 3.0% sulfur and natural gas. Types of fuel burning equipment included underfeed stokers, spreader stokers, wet and dry bottom boilers and cyclone boilers.

The second category of prime movers evaluated included gas turbines operating from 150 kW to over 80 MW electrical generating capacity. Fuels included kerosene, natural gas, and diesel fuels from .01 to .5% sulfur content.

Diesel- and gasoline-fueled internal combustion engines were considered in an operating range of 100 to 500 kW.

In total, prime movers generating from 100 kW to 100 MW were considered for air, water and noise emissions.

A second component evaluated as part of the ICES included auxillary heat sources. Incineration is the most common and environmentally detrimental auxillary heat source for ICES designs. Heat from incinerators can be used to generate steam for power generator or used for space heating or domestic utilities. Incinerator evaluation included municipal, industrial and sludge incineration facilities burning from 100 lbs per hour to over 500 tons per day.

The third major component in ICES is concerned with utility generation. Utility generators include chillers, electrical generators and heat exchangers. Also included in this category were transformers, substations, and other electrical transmission equipment.

To determine environmental emissions associated with each unit in the ICES, the most probable range of operating parameters were determined. Next fuel input was characterized. Whenever test or actual performance data was available, it was used as the best estimate of uncontrolled emissions. As a second alternative, emission factors were applied to estimate emission rates.

As expected, coal-fired boilers presented the worst environmental emission characteristics. Uncontrolled boilers in all size ranges, designs, and fuels violate either state, local or federal standards. Wastewater emissions from ash transport, cleaning and blowdown, although not subject to NPDES requirements, do require treatment. Noise levels from coal mill operation exceed federal and state noise standards requiring noise isolation. Siting and zoning regulation is particularly biased against location of such facilities near residential areas.

Oil boilers face potential environmental concern when higher sulfur fuels are used. Water, noise and air pollutant problems are not nearly as severe as in the case of coal-fired units. Zoning and noise restrictions still present difficulties to ICES planners wishing to use larger oil-fired boilers near residential areas.

Aside from prime movers, incinerators present the next greatest expense from a control viewpoint. Larger incinerators to meet federal or state

standards must employ air pollution control equipment. As in the case of other utility-oriented equipment, incinerators will require noise isolation to meet state noise regulations for residential land use.

Overlay of ICES Emissions on Federal, State and Local Environmental Regulations

As discussed earlier, a filtering or sieve technique was used to determine regulatory impediments to ICES components. Zoning regulation, because of its subjectivity, has been treated independently and will be discussed later.

When ICES component emissions are compared with federal air, water, noise and siting regulation, a matrix can be constructed. Federal regulation and legislation tends to be general in nature. Federal air pollutant regulations limiting emissions for new sources in specific source categories presents the most definitive set of federal rules applicable to ICES components. NPDES standards resulting from the Water Pollution Control Act are definitive but only apply to energy facilities larger than ICES. Aside from specific OSHA emission limitations, the federal government has not yet set specific rules governing energy generating facilities.

As previously mentioned, a variety of federal legislation influences ICES components either indirectly or in a general sense.

It should be noted that aside from air and water laws, federal legislation tends to restrict development associated with ICES prime movers in areas where wildlife or natural water resources may be threatened.

When the spectrum of ICES components are passed through a filter consisting of federal regulations required, environmental controls could be determined. It should be noted that these controls are a result only of direct federal regulation. Many federal programs such as the Clean Air Act or the Coastal Zone Management Act have resulted in the establishment of state regulations which impact ICES components.

In addition to federal controls are environmental impact statement requirements and general siting restrictions. Since the predeterminant of an environmentally acceptable EIS is conformance with state and local regulation, all ICES components should be subject to state and local regulatory screening. Assessment of a project such as EU (Environmentally Unacceptable) or ER (Environmental Reservations) because of nonconformance with state or local regu-

lations will prevent commencement of a project and require at least four additional months for revision, review and acceptance of project modifications.

Unfortunately for comparison and analysis, state and local environmental regulations are not uniform across the country. Sulfur oxide emissions in the northeast, for example, place severe restrictions on coal burning while southwestern states tend to have stricter particulate emission standards.

The same methodology applied to federal regulations has been applied to state and local regulations. Analysis of state SIPs indicate that 41 states have more restrictive particulate regulations, 39 states have more restrictive SO₂ regulations and 7 states have more restrictive NO_x regulations. In most cases, additional state regulatory control lowers the 250 x 10⁶ Btu/hr boiler size to include all size units.

While some states have enacted statewide or local regulation which lower the cutoff point, certain states have found it necessary to also reduce the emission level allowed under federal standards. Particulates from incinerators, sulfur oxide emissions and thermal discharges from power generating facilities are of prime concern as reflected by the stringency of local law.

To summarize environmental regulatory control, the federal government has established regulations restricting pollutant emissions from ICES components. The components regulated and include fossil-fueled boilers and incinerators. Some states and their municipalities have established laws which restrict those emissions further. The resultant effect is an increased need for particulate, SO₂ and thermal control.

The federal government, while establishing general noise standards for construction equipment, and noise exposure standards for HUD projects, has not yet established national emission limitations for ICES type sources. States, however, have three categories of law which can be used for enforcement of noise emissions. Four states, including Colorado, Illinois, New Jersey and Oregon have passed state-wide noise limitation regulations for residential and/or commercial land use.

States also have OSHA standards for noise exposure which can be enforced to limit internal noise exposure. OSHA standards restrict noise exposure in power plants to 90 dba for 8 hours with a sliding scale of noise levels and exposure durations to 115 dba for 1/4 hour.

The third category of regulations and perhaps the category having the greatest influence on ICES design is the local or county zoning ordinance. Almost every zoning law has a provision for noise emissions. More sophisticated ordinances have performance standards restricting maximum sound levels by frequency of emission and land use.

State and Local Siting Regulation on ICES Development

When siting regulation is discussed, environmental regulation is implied since the foundation for most siting law is environmental preservation. Often in the case of zoning ordinances, regulatory control has created areas of uniform land use or set minimum performance standards as designated by the community. State utility commissions have set standards for air pollution, water pollution, water use, and land use for electrical generating plants and transmission lines. Thirteen states require review of air pollution controls as part of their certification process, twelve require a review of water pollution controls, ten a review of water use, and fourteen a review of land use.

Zoning and utility siting certification generally reinforce compliance with local environmental law. In the case of noise control and site parameters, local ordinances can greatly inhibit project construction.

While recent applications of Total Energy Systems in nonindustrial settings have experienced few siting problems related to local zoning regulation, it is still unclear whether such a favorable situation will generally be encountered in the case of Integrated Community Energy Systems. Many factors may contribute to a different public and regulatory reception, e.g.,

- Total Energy Systems were largely gas-fired; ICES fuels may include coal, oil, and solid waste and thus have a greater potential for nuisance generation.
- ICES may include nonenergy utility generation facilities (e.g., water and waste treatment plants, incinerators, landfills) again with a higher potential for nuisance generation.
- ICES prime mover sizes could range as high as 30-100 MWe; whereas, TESs are typically less than 5 MWe.

Application of ICES would require technologies that, under present district definitions, are often classified as industrial uses. These technologies would then be excluded from residential and commercial areas where potential applications exist. The light and heavy industrial uses that may be a part of new energy systems could be regulated in restricted zoning districts subject to site plan review. If the performance of a community energy system were to be environmentally tolerable, with acceptable levels of noise, pollution, and other nuisances, it could be included in districts where it would otherwise be banned, through the use of performance controls.

To examine the possible impacts of existing zoning regulations and procedures on ICES implementation, zoning ordinances covering a range of local development intensities were selected arbitrarily for examination by:

- SMSA membership,
- County or municipality, and
- Municipal population size distinctions.

Zoning ordinances of the ten counties and municipalities, as well as three model zoning ordinances, recently drafted by regional or county planning agencies to aid local planning agencies, were reviewed to determine:

1. The types of land uses allowed in each zoning district,
2. The presence of provisions designed to facilitate common-site, multi-building development,
3. The types of ICES components permitted in each zoning district, and
4. The presence of district-specific performance standards.

Of the three county ordinances, seven municipal ordinances, and three model ordinances studied, only one provided for a single zone mixed land use of residential, commercial, and industrial activities.

Restrictive provisions of traditional zoning ordinances combined with administrative inflexibility continue to impede the diffusion of innovative community design features. With regard to Community Energy Systems, two broad areas of zoning impact are evident:

1. Zoning can limit the use of community forms that are energy conservative, in part, because of higher residential energy demand densities, the use of building/site arrangements that reduce space conditioning requirements and automobile use, and efficiencies arising from a mutually supportive mix of different land uses.
2. Zoning can restrict the actual siting of ICES components within a community, many of which are considered heavy industrial land uses.

Examination of these problem areas associated with local zoning can be focused on five specific issues:

<u>ICES/ZONING ISSUE</u>	<u>PRIMARY RESTRICTIVE ORDINANCE FEATURE</u>
1. Residential density required to support a community energy system.	Minimum lot size
2. Building-site relations in multi-building complexes.	Yard and setback requirements
3. Opportunities for mixed land use communities.	Use districting
4. Siting of ICES components in non-industrial districts.	Use districting
5. Level of environmental control effort required for ICES application.	Performance standards

Existing zoning provisions and emerging regulatory innovations could offer developers more latitude in the design of energy conservative communities and in the application of Integrated Community Energy Systems. These include:

- *Zoning Regulation Exemptions* for Community Energy Systems that are considered public utilities or are municipally owned,
- *Addition of ICES* to special use lists for permit approval in multi-family residential districts,
- *Accessory Use* classification of minor ICES components such as building cooling towers and heat pumps,
- *Amendments* to use lists which would allow mixed land uses in restricted use districts, and to rezone land for the purpose of ICES siting,

- *Special Use* procedures that may allow nonindustrial district ICES siting while ensuring adequate public review,
- *Innovative Performance Controls* that enable developers to use energy conservative building and site designs,
- *Industrial Performance Standards* that will be necessary to ensure ICES' environmental acceptability, and
- *Planned Unit Development* processes that foster integrated community planning and design innovation, and which provide opportunities for municipal/developer bargaining to balance the financial requirements of the developer with the needs and desires of the community.

Cost of ICES Regulatory Compliance

Costs associated with regulatory compliance can be subdivided into six categories:

- Costs associated with engineering and technical environmental studies of the ICES;
- Costs associated with liaison with federal, state, and local regulatory bodies;
- Costs associated with construction and operation of control equipment;
- Costs associated with environmental sampling, monitoring, and analysis;
- Costs associated with required use of alternative fuels;
- Costs associated with nonoptimum land use to meet zoning requirements.

When comparing the above costs with larger energy facilities or on a cost per unit of energy delivered, the ICES is unable to spread expenditures over a large base. The result is larger per unit or per capita control costs for ICES than for larger central stations. Costs relating to engineering studies and agency liaison can vary greatly depending upon the complexity, size, and location of the ICES development. When comparing ICES costs for these operations with central system costs, consideration must be given for the fact

that ICES analysis considers an entire community development rather than a single facility. Planning and implementation may occur over several years. Given a two year planning horizon for small ICES (up to 5 MW) and five years for larger ICES, a rough estimate of ICES environmental engineering analysis and liaison activities would be from \$10K to \$150K, or from \$6 to \$100 per kW on small developments and from \$1.5 to \$30 per kW on large developments. Alternative unit costs for large central systems are likely to be less. For a 1,000 MW plant, the lowest level of ICES engineering costs would allow over \$1.5 million dollars to over \$30 million dollars for environmental planning engineering and analysis. Such costs would be less than \$1 per kW of installed capacity.

When comparing costs for sampling, analysis, and monitoring the larger central plant again has the advantage of economy of scale. Large central plants require continuous monitoring, site monitoring, and sampling calibration checks from two to four times per year. Despite large expenditures for sampling and monitoring, these costs are not expected to exceed \$.25 per kW of installed capacity annually. Small ICES have no monitoring or sampling requirements. Data required for impact statements can be obtained from alternative sources with no cost impact to the developer. ICES greater than 25 MW, however, as in the case of environmental analysis, are confronted with continuous monitoring requirements, sampling and calibration and the added problem of a high residential density near the source. Sampling, monitoring, and analysis for a 25 MW plant could easily exceed \$1 per kW of installed capacity annually.

Costs associated with nonoptimum land utilization are difficult to assess. Both central stations and ICES will confront land utilization problems with local planners. Large central stations require larger power facility sites and transmission pathways. ICES while not confronted with cooling pond and transmission line land use problems must satisfy mixed land use zoning requirements. Again, larger ICES using large fossil-fired units (above 5 MW) are likely to have proportionately greater siting problems.

The final cost components associated with environmental regulatory control is construction and operation of control equipment and the use of alternative fuels.

Particulate control can be achieved using either fabric filtration on smaller combustion sources or electrostatic precipitators on larger units.

Scrubbers can also be used for particulate control but remains the most costly control alternative when only particulate control is required. Based upon data from the NUCLA Station of the Colorado Ute Electric Association, unit capital costs for \$85/kW can be maintained for particulate control with annual operating costs totalling 1.53 mills per/kWh. Comparable costs for particulate control in large central stations is about \$65/kW with an annual operating cost of about .1 mill per/kWh. In the case of flue gas desulfurization, the cost penalty for smaller systems is more apparent. Based on joint TVA-EPA data, capital costs for small fossil plants range from \$60/kW to \$98/kW using lime as the least capital cost intensive and the Cat-ox process as the most expensive. For power plants in the 50 MW range, a cost of \$115 to \$120 per kW is more realistic. These costs contrasted with capital costs of \$33/kW and \$70/kW for a 1,000 MW plant. Estimates made in the same study are based upon a 30-year life and onsite solid disposal with 90% control. Operational costs for flue gas desulfurization units are relatively constant over size in the range of 2.2 to 3.3 mills/kWh.

Thermal control is the single emission problem which larger central plants must control, while larger ICES need no control. Based on recent costs of cooling pond and tower operation, capital costs for large central plants are about \$6 per kW installed capacity with annual operating costs of .18 mills per kWh.

Another approach to emission limitation of particulates, sulfur oxides, and nitrogen oxides is the use of alternative fuels. Based upon a tally of fuel prices by sulfur content on coal orders less than 500×10^3 tons, use of low sulfur coal appears to be the least cost SO_x control option. Price differentials for coal burned in ICES and meeting environmental regulations against coal violating regulations is minimal when compared to the cost of FGD. Some northeastern states will still require scrubbing or use of lower sulfur alternative fuels.

Oil does not appear to have the same price structure as coal. The cost differential between high and low sulfur oil (between .2% and 2%) is as much as \$.70 per 10^6 Btu. Operation of a 50 MW power plant 8,000 hours per year would cost an additional \$3.2 million in fuel annually. This compares with an approximate \$8 million cost for a scrubber with total annual charges of \$1.0 million (excluding capital charges).

In this case, low sulfur fuel oil would be more economical only if the utilities cost of capital exceeded 22%.

1 IMPACTS OF ENVIRONMENTAL REGULATIONS ON THE DEVELOPMENT OF COMMUNITY ENERGY SYSTEMS

1.1 INTRODUCTION

The emergence of federal and state environmental regulations will impact directly the design, siting, and economics of community energy development. A combination of air, noise, and water control regulations place specific constraints on emissions, not only from large central grid power systems, but also from many smaller community systems. Proposed federal and state regulations -- depending upon local environmental quality -- may prohibit the construction of certain systems or require extensive environmental controls.

This study reviews existing and proposed environmental regulations affecting community energy systems. Regulatory impacts on large, central grid stations also are examined in the context of an alternative approach to community energy production.

A spectrum of designs is included in the study, from small developments using gas turbines to large community developments using steam turbines fueled by coal, oil, or solid waste. The study is regionalized and considers local air quality and fuel availability.

Potential costs to Community Energy Systems Developers to comply with environmental regulations are assessed. These costs are compared with alternative costs associated with large centralized grid systems. Fuel availability, control costs, siting restrictions, and other constraints imposed by environmental regulations are summarized to assess future impacts and trends relating to community energy development as an alternative to central grid systems.

1.1.1 Scope

This study is restricted to the energy system and does not encompass potential regulatory constraints imposed on other utility systems. Thus, the community energy system may be a subset of a totally integrated utility system. For purposes of analysis, the energy system may also (as in the case of a large metropolitan building) be an isolated system using traditional sources for other utilities. The energy system has been subdivided into operational components, and each component has then been reviewed for air, water, noise, and solid waste emissions. Emissions are compared with local regulations to

determine where regulatory thresholds exist and under which system design and operating parameters they will be exceeded. After identifying regulatory constraints on the energy system, control strategy and economics are reviewed.

1.2 CHARACTERIZATION OF COMMUNITY ENERGY SYSTEMS

Energy Systems have been characterized in various ways.

- *Integrated Energy Systems* include selective energy systems, total energy plants, as well as integrated utility systems and urban energy systems. From the view of energy production, conversion, and utilization, all these systems have common environmental considerations.

- *Community Energy Systems* integrate energy production and consumption into a single system in a manner that minimizes total energy utilization. Most systems entail the integration of electrical production, space conditioning, and domestic water services. Certain other utilities, such as waste treatment and disposal as well as fire protection, may be incorporated into the system to conserve additional energy.

1.2.1 Community Types

The size of a Community Energy System's load may range from that of a single-family home to an entire community or cluster of communities. The important characteristic of the Community Energy System is integration of energy production and end-use to recycle energy that otherwise would be wasted. Table 1.1 shows examples of community types likely to accept energy systems.

Although the community type does not necessarily affect the character of the energy system, it will dictate the size of the system and the ability to recycle component wastes. For example, heterogeneous communities would provide greater latitude for using available wastes than would a homogeneous system. Community systems that incorporate industrial plants requiring process steam, can utilize boiler generated steam from a coal energy plant and at the same time provide domestic heating and steam for electrical generators.

The approach of this study is not to look at any one specific type or size energy system, but to investigate individual components of energy systems. Analysis is performed using a range of component sizes. To determine regulatory impact on a specific energy system design, individual component sizes can be

TABLE 1.1. Examples of Community Energy System
Community Types¹

<p>A. Large Single Structures</p> <ol style="list-style-type: none"> 1. Residential <ol style="list-style-type: none"> a. Townhouses b. Apartments c. Condominiums 2. Commercial <ol style="list-style-type: none"> a. Shopping center b. Commercial building c. Office building d. Parking facility 3. Industrial <ol style="list-style-type: none"> a. Factory b. Warehouse c. Multicompany condominium d. Multicompany rented facility 4. Special Purpose <ol style="list-style-type: none"> a. Sports arena b. Amusement facility c. Airport d. Correctional facility 	<ol style="list-style-type: none"> 2. Commercial <ol style="list-style-type: none"> a. Shopping complex b. Building complex 3. Industrial <ol style="list-style-type: none"> a. Industrial park b. Company complex 4. Mixed <ol style="list-style-type: none"> a. Commercial/industrial b. Residential/commercial c. Residential/industrial d. Residential/commercial/industrial 5. Special Purpose <ol style="list-style-type: none"> a. Airport complex b. Sports complex c. Amusement park d. Prison complex
<p>B. Building Complex</p> <ol style="list-style-type: none"> 1. Residential <ol style="list-style-type: none"> a. Apartment complex b. Condominium complex c. Small town d. Central city development e. P.U.D. 	

determined. Emissions and regulations impacting those components then can be found in the appropriate section.

1.2.2 *System Components*

Energy system components can be described in a variety of ways. Because of the variation in potential designs, system components are first identified in general terms. Specific pieces of equipment then are categorized under each system component. Figure 1.1 shows a general schematic of a typical energy system.

Major system components include the following subdivisions:

A. Prime Movers

1. Internal combustion engines
2. Steam generators
3. Combustion turbines
4. Other technologies

B. Ancillary Heat Sources/Energy Converters

1. Incinerators
2. Waste heat utilization/heat exchangers

C. Utility Generators

1. Electric generators/substations/transformers
2. Chilled-water generators
3. Hot-water generators
4. Hot- and cold-air generators

● *Prime Movers.* Mechanical generators may be driven in four basic manners. Internal combustion (IC) engines are used to generate mechanical energy which is directly linked to generators, compressors or pumps. Engine sizes range from a few horsepower to tens of thousands (Bhp) units. The largest IC engines for power generation will range up to 10,000 or 15,000 (Bhp).² IC engine application in ICES is not limited to electrical generation. In a recent survey of stationary IC engine application, approximately 10% of IC engine capacity is used for pump and compressor drives. The sizes of these engines range from 1,500 to 2,500 Bhp. About 10% of the engines surveyed are used in total energy plants with capacities to 1,500 Bhp. Another 80% of the engines surveyed

Figure 1.1 Schematic of a Community Energy System

are used for standby electrical peaking or continuous electrical service. The widespread use of IC engines in electrical generation make them likely candidates for most smaller community energy systems. They have proven reliability and established maintenance procedures.

Furnaces generating steam which operate steam driven turbines provide a second source of rotational energy for electrical generator or compressor operation. Although boilers may be nuclear, electrical, or fossil-fired, pending technological breakthrough, ICES will use only fossil-fired boilers to generate steam. Only under limited design conditions would electrical steam generators be used to drive chillers, provide heat, or process steam.

Electric boilers are available up to 150 Bhp with pressures as high as 300 psig. Because their application is unlikely, little attention has been given to electrical boilers. Direct environmental effects of electrical boilers are negligible; makeup water and system purge are the only issues of direct environmental concern, their impacts are similar to those of fossil steam generators.

Fossil-fueled boilers are the most likely mechanisms for producing turbine steam. ICES can provide significant increases in system efficiency by using waste products to generate other utilities. While boilers can be custom-built, small package boilers are available from 15 to 2,000 Bhp. Potential fuels for firetube and watertube package boilers are one of the six grades of fuel oil, natural gas, propane, butane, sewage gas, or coal. Emissions depend on the type of fuel used, the firing method, the size of the unit, and the design parameters of the boiler itself. Pollutants of greatest concern are sulfur oxides in the combustion of coal or oil, carbon monoxide, hydrocarbons, and nitrogen oxides. Any review of environmental implications of boiler operation must consider these parameters.

The third approach to the production of shaft energy is the combustion turbine. Combustion turbines are currently in widespread use for electrical peak power production. Table 1.2 illustrates the penetration of combustion turbines for generation of electricity in the 11-80 MW range. Figures concerning the distribution of generating plants by size come from FPC and Reliability Council reports. Table 1.3 shows the projected 1984 distribution.³ Although diesel units predominate in energy production in the 1-10 MW range, combustion turbines are used widely for heavier electrical demands. Fossil units, although

TABLE 1.2. 1974 Mix of Mechanical Equipment Used as Prime Movers in Electric Production
(% of units)

MW	Coal	Fossil Oil	Gas	Combustion Turbine	Diesel	Combined Cycle	Other
1-10	4.5	1.5	3.0	5.4	83.7	0	1.9
11-20	7.6	6.6	21.9	44.8	16.2	1.0	1.9
21-30	13.3	8.9	18.9	46.7	7.8	0	4.4
31-40	23.2	11.6	18.6	37.2	4.7	0	4.7
41-50	11.6	11.6	37.2	34.9	0	2.3	2.3
51-60	10.7	7.1	32.1	46.5	0	0	3.6
61-70	25.8	25.8	12.9	32.3	0	0	3.2
71-80	13.1	5.3	36.8	39.5	0	0	5.3
81-90	25.0	25.0	20.0	25.0	0	0	5.0
91-100	5.9	29.4	17.6	35.3	0	0	11.8
>100	39.8	21.9	20.1	9.7	0	.6	7.9

Note: See Reference 3.

TABLE 1.3. 1984 Mix of Mechanical Equipment Used as Prime Movers in Electric Production
(% of units)

MW	Fossil			Combustion Turbine	Diesel	Combined Cycle	Other
	Coal	Oil	Gas				
1-10	3.0	1.0	2.5	5.0	79.1	0	9.4
11-20	4.1	6.2	14.4	46.4	21.7	1.0	6.2
21-30	11.9	7.1	14.3	51.2	8.4	0	7.1
31-40	14.3	6.1	18.4	47.0	2.0	2.0	10.2
41-50	16.6	9.5	28.6	40.5	2.4	0	2.4
51-60	9.7	0	29.0	54.8	0	0	6.5
61-70	16.7	23.3	16.7	40.0	0	0	3.3
71-80	12.5	0	28.1	53.1	0	0	6.3
81-90	31.6	10.5	26.3	26.3	0	0	5.3
91-100	4.8	9.5	23.8	47.6	0	0	14.3
>100	42.1	18.4	15.3	10.7	0	2.5	11.0

Note: See Reference 3.

used for light electrical production, are used more extensively to produce greater amounts of electricity.

The last general category of prime movers includes hydroelectric power generation, wind, tidal and geothermal power. In each case, some sort of natural phenomenon causes the movement of a mechanical device which essentially converts "natural power" into shaft energy. The shaft energy then is used to produce electric power. These technologies have special developmental problems and have specialized application and use. Environmental problems relating to these technologies are also "special case situations," because most federal, state, and local regulations do not apply directly to these technologies. Thus, they are not addressed in this study.

- *Ancillary Heat Sources/Heat Exchangers.* Two general approaches can be used in integrated community energy systems to supply additional energy to the system. Utilization of waste and waste heat to produce additional utilities significantly improves the total efficiency of the energy production/utilization cycle.

The first approach to ancillary energy production is incineration. Incineration of waste materials, ranging in heating values from 6,000 to 10,000 Btu/lb, can provide a community with an inexpensive fuel and reduce the community's solid-waste-disposal problem. Operation of incineration for waste disposal, produce large quantities of airborne pollutants. State and local governments have established strict regulations concerning the location and operation of incinerators. Emissions of major concern include particulates, sulfur oxides, carbon monoxide, hydrocarbons, and nitrogen oxides. Control of the combustion reaction and the design of the incineration chambers to reduce particulate entrainment are important. Using incineration as a heat source to produce steam or hot water requires the inclusion of firetubes, watertubes, or some sort of sectional chamber. Depending upon the size and use of the incinerators, it may also include the installation of movable grates and material handling equipment. Incinerators, employed to produce steam, are more sophisticated than simple hot water heaters for domestic heating and hot water. Although incinerators to produce energy could be restricted by New Source Performance Standards (NSPS), it is not likely that they will operate in the 250×10^6 Btu/hr range. Most probably, smaller incinerators with charging rates of 2-4 tons/hr and heat inputs of less than 60×10^6 Btu/hr will represent the upper size range in most ICES. Although NSPS will not restrict operation of these units, potentially strict

state and local incinerator regulations could inhibit widespread use of these ancillary heat sources.

Incineration converts waste materials and sludge into heat to produce steam. Conservation and greater system efficiency is achieved by using formerly wasted material. Waste heat utilization applies essentially the same principle except that formerly wasted heat is recycled.

In cases where steam or water of higher temperature is used as a heat source, a heat exchanger is usually employed. Heat exchangers generally consist of one jacket situated inside another, each jacket containing a medium, one from the heat source -- the other going to the space requiring heat. Media transferring the heat may be the same such as water-to-water or may be mixed such as water-to-air, steam-to-water, or steam-to-air.

- *Utility Generation.* Community utilities generally include water supply, fire protection, waste disposal and treatment, electrical generation, heating, and cooling. This study addresses utilities directly integrated with the energy system and having environmental emissions that are restricted by federal, state, or local law. As a result, utilities such as fire protection, waste treatment (excluding incineration) and drinking water supply are not investigated. Such utilities do not have a direct involvement with energy production or they have no significant potential for violating federal, state, or local statutes.

All community energy systems rely on an electrical generator central to the system. Depending on the system design, it is expected that the electrical generator will have adequate backup capacity and/or interconnections with other sources of electrical power. Although three types of generators are potential candidates for ICES, mechanically driven AC or DC generators are most likely to be used. Advanced solar generators and chemical generators also could supply ICES power; however, advanced electrical generation has particular problems not addressed in environmental regulations.

Most ICES are expected to integrate chilled water generation with the energy system because such an integration has the potential for an overall increase in system efficiency. Motor-driven and absorption chillers are the two major types of generators likely to be used in any system.

Hot water generation, like chilled water, can improve system efficiency if it is integrated with the generation of other utilities. Heat exchangers are the prime mechanism for the generation of hot water. Forms of energy used to heat water will vary and often several may be employed. Heat exchangers may be steam, water, electrical or direct fired.

1.2.3 Community Size vs System Size

To assist in examination of ICES emissions, environmental regulations and siting constraints, it is desirable to place system component sizes in perspective with community size. This section presents examples of mechanical equipment capacity with community characteristics such as development size described as square footage, number of apartments and building types.

The study of these relationships is by reference to previously designed (though not always built) systems rather than by theoretical argument. The design of ICES systems currently involves iterative experimentation based on specific examples. There is not yet enough knowledge to design "optimized" ICES systems.

The purpose of this section is to provide a rough idea of the size of system components that might serve a building, community, or building cluster of a given size. Knowing the approximate size of equipment that might be impacted by environmental regulation, other tables in this report may be used to determine which regulations might have to be complied with in the ultimate design. For a developer, such knowledge may be especially useful when it informs him in early phases of design of potentially costly environmental regulations or when it helps him to schedule construction and acquisition of permits in such a way that costly delays are avoided.

This section is geared toward the small ICES, and it is assumed that utilities will be involved with the largest ICES. In general, larger utilities are familiar with the specific local environmental regulations and the procedures necessary for compliance. Thus, when a major utility designs a large steam-electric cogenerating ICES, it will already have better knowledge of community demand patterns and environmental regulations than can be provided in this report. The community developer is likely to enter the energy field relatively ignorant of the kinds of ICES capable of serving his community and of the kinds of regulations affecting the economic viability of a given ICES configuration.

This section attempts to inform the community developer of various ICES options and provide information thereon.

Figure 1.1 shows a general schematic of a typical ICES. The characteristic of an ICES which differentiates it from other energy systems is its generation (and use) of joint energy products from the prime mover of the system. Generally these joint products are electricity and heated water (hot water or steam). These products are combined into a system which provides energy for appliances, heating and cooling. Neither form of energy needs to exclusively serve any one of these needs. For example, electricity may be used to provide domestic hot water or heated water from the prime mover and may serve this need. Typically the latter is true.

Heated water from the prime mover is invariably used to provide heating but electricity is often used at the same time to meet the same need at different locations in the community. Some of the ICES listed in Appendix A include both electrically driven heat pumps and heated water to provide heat. An advantage of this design feature is load matching. Here the peak electrical (heating) loads occur at the same time as the peak heated water heating loads. In this case there is less need for energy storage or supplementary peaking (see MIUS models A, G, and J in Appendix C). When electrical loads placed on the prime mover do not match the demand for heated water from the prime mover, it is necessary to add energy storage or peaking components. As illustrated, the peaking component is typically a boiler. However in some cases, heat extraction from an incinerator may be used to obtain energy from garbage.

Although ICES may not provide cooling, all ICES examined provide cooling. Although heating often is provided exclusively by heated water, cooling nearly always is provided by a combination of electrically-driven compression chillers and steam-powered absorption chillers. This combination is called floating air conditioning. By a "floating" adjustment of the combination of compression and absorption chillers operations, the optimum system cooling efficiency may be obtained. As previously discussed, ICES components examined include prime movers, peak supplement units, and cooling equipment. In the smaller ICES listed in the Appendix, prime movers were restricted to gas and diesel engines and turbines. Peak supplement units employ small boilers and sometimes incinerators. Cooling is supplied by absorption and compression chillers.

This list does not include technologically advanced systems, such as solar generators or fuel cells. Such systems are not yet economical components of ICES. Consequently they are not now installed or designed into most ICES. Further, there are no environmental regulations currently written for the more advanced technology. The technologies discussed here are commonly used, state-of-the-art components impacted by current environmental regulation.

Because the ICES concept hinges around joint use of electricity and residual heat, only those forms of electrical generation dependent on heat energy are potentially prime movers for an ICES. Electricity from mechanical energy (hydroelectric, wind, or tidal) may be added to an ICES but it will not fit the criterion as a prime mover.

Thus the largest prime mover complex in Appendix C has a total generating capacity of 60 MW. The largest individual internal combustion prime mover would be about 5 MW.

The figures presented should be taken only as approximation and used only for rough first phase planning. There are numerous causes of variation in the prime mover capacity per thousand square foot figures shown in the table. These include:

1. climate,
2. connection to the conventional electrical grid for some electric demands,
3. type of building use and construction,
4. combinations of building types,
5. percentage of backup capacity provided,
6. quality of the original source of data, and
7. accuracy of estimates derived from the original source.

Despite the approximate nature of the data there is still enough information to allow a project planner to develop initial estimates.

Both theoretical and actual data are included. The statistics are dominated by theoretical studies primarily because data on most of the many operating systems have not been collected. The maximum per thousand square foot capacity in an installed facility is 13.1 kW in a shopping center in Texas. It is interesting that the prime mover capacity listed for the other operating shopping center is 12.5 kW per thousand square feet (with grid connection) in Pennsylvania.¹⁵ The smallest prime mover capacity per thousand square feet in

an operating facility is 2.6 kW for the Rochdale Village apartment complex in New York City.⁵ Intermediate between these figures is the 7.3 kW per thousand square feet figure for an office building in St. Louis.¹⁵

The theoretical studies rank the shopping center, office building, and apartment complex in a similar order. The only shopping center individually studied had a prime mover capacity of 8.9 kW per thousand square feet in Houston.⁴ The two office buildings individually studied had capacities of 7.7 kW/ thousand square feet for Houston⁴ and 7.8 kW/thousand square feet for New York¹³ (the full lighting case). Many apartment complexes were studied, having prime mover capacities from 3.1 kW/thousand square feet in Dallas¹⁴ and Minneapolis¹⁴ to 7.6 kW/thousand square feet in Houston.⁴

A close look at ICES evaluated shows that prime mover electrical capacity does not seem to be related to climate. This occurs because the electrical loads served by the prime mover of an ICES generally are not weather dependent loads. The prime mover usually generates electricity to meet appliance and lighting loads. These loads usually must be supplied by electricity and are occupancy-dominated rather than weather-dominated loads.

Peak supplement heat sources are the components of an ICES system that are sensitive to weather loads which are the cooling and heat components. Only the peak supplement heating components cause environmental difficulties, so they will be discussed here while cooling components will be ignored.

The explanation for the high capacities provided in the NASA-MIUS studies⁵ is that incineration was used as a peak supplement. In this case, the intention was to utilize all energy available from the solid waste generated by a community of 100,000 people.

Only the NASA-MIUS (ICES) complexes serving the central business district and the village centers used incinerators as a peak supplement; whereas, the neighborhood ICES used the more typical method of providing a boiler for peak supplement heat. The NASA-MIUS study considered numerous ICES (rather than a conventional power plant) serving a community of 100,000.

Disregarding the NASA-MIUS incinerator capacity per square foot factors, the maximum steam boiler horsepower per thousand square feet figure of 1.2 hp is found for an apartment complex in Minneapolis.¹¹ The lowest hp/thousand square feet figure for apartments is 0.2 for Houston and Dallas. The value of zero for Rochdale Village in New York is deceptive because a variable extraction

turbine is used for this particular ICES.² With this particular prime mover technology, the proportion of electrical and steam output may vary. Because heating demands peak at night and electrical demands peak during daylight, the flexibility of this prime mover probably substitutes for a peak supplement boiler. Some conflict appears to exist between the theoretical and actual need for boilers in office buildings and shopping centers. Some of the theoretical studies indicate no need for a boiler, whereas, one theoretical study and three actual ICES indicate a capacity need from 0.6 to 1.0 hp/thousand ft². In at least one of these cases¹³ the boiler is used to provide added cooling by providing steam for the absorption air conditioner. This is a very inefficient use of fuel and is only adopted when the peak cooling demand is very brief.

In forced air heating and cooling systems, heat exchangers are used to transfer energy from centrally generated hot and chilled water to forced air, which is then used as a medium for space conditioning.

1.3 EMISSIONS FROM ENERGY SYSTEM COMPONENTS

Environmental emissions associated with ICES components include air pollutants, water pollutants, thermal emissions, and noise emissions. Land-use-related environmental impacts of ICES components are a topic of great concern to ICES development and are treated separately in Chapter 2. Land use and environmental quality are interlinked such that land-use regulations are based on emission and air quality parameters, and the relationship between air quality and emissions is directly related to land use. The objective of this section is to isolate and characterize environmental emissions from ICES components. Environmental degradation from ICES components is only described in terms of mass emission rates. The preferred measure of environmental degradation, namely air quality, is not easily identifiable.

Although greater mass emissions relate directly to air quality, the specific relationship between emission rates and air quality also depends on local meteorology, terrain and site design, and emissions attributable to other local sources.

Because air quality associated with a specific source is not easily quantifiable, most state, local, and federal regulations impacting ICES are mass emission oriented. In other words, restrictions on the development of ICES can be established by estimating component emissions and contrasting them with established emission regulations. It must always be kept in mind,

however, that air quality is the overriding determinant in deciding if an ICES will be an acceptable source in any given community.

1.3.1 *Emissions from Fossil-Fueled Steam Generators*

Fossil-fueled steam generators include oil-, coal-, or gas-fired furnaces designed to produce steam. Steam from such a unit then can be used in industrial processes as a source of heat to generate hot air or water or to turn steam turbines that drive electric generators or refrigeration units. Essentially, all fossil-fueled combustion equipment is similar in operation. All such units have a burner to combust the appropriate fuel, a firebox, a heat exchanger, and a means of transferring hot gases through the firebox to heat exchanger and out the stack. Although this section is directed at steam generators, the same principles and environmental emissions apply to water heaters.

As illustrated in Table 1.3, fossil-fuel steam generators account for about 9% of installed prime movers with a generating capacity from 1-10 MW. This percentage increases to 36% in the 11-20 MW range, to 41% in the 21-30 MW range, and to 54% in the 31-40 MW range.³ Economies of size and fuel costs favor fossil-fuel combustion for larger generating units. Capital costs and maintenance tend to discourage smaller fossil-fuel steam generators. Environmental emissions from fossil-fired steam generators include combustion by-products and waste emitted to the atmosphere, noise associated with ancillary mechanical equipment, and waste heat. The primary environmental problems associated with fossil-fuel combustion are SO₂ emissions from oil and coal combustion, particulate emissions from coal combustion, and NO_x emissions from coal, oil, and gas combustion at high temperatures. Waste problems are minimal and only of concern during "blowdown" of the system or if makeup water is to be used to make consumed process steam.

Noise emissions from prime movers, especially auxiliary equipment, can be significant and difficult to control when there are adjacent residential areas. Noise emissions are subject to a variety of federal, state, and local ordinances, each having little relationship with the others. Loudness of sound depends on intensity, frequency, duration of the sound, the sound pressure, and the rate of change in sound pressure. Intensity is commonly measured in decibels. A 10 decibel increase in sound intensity corresponds to a doubling in the perceived loudness. Frequency influences the perception of loudness. Sounds

between 2,000 Hz and 8,000 Hz are "noisier" to the human ear than sounds outside this frequency range. Duration of sound corresponds directly to an equivalent db increase. Likewise, impulsive sounds appear noisier than gradual changes in sound pressure. While there are many approaches to quantifying sound "noisiness", the most common approach and that used in this study and in many regulations, is a decibel level of sound intensity with its associated frequency. db level by frequency is commonly used in zoning ordinances and provides a suitable approach for comparing emissions with regulations.

- *Emissions from Oil-Fueled Combustion Steam Generators.* Five principle air pollutants are of major concern in oil-fueled combustion: particulate, CO, NO₂, Hydrocarbon, and Aldehyde emissions. Two of the contaminants, SO_x and inorganic ash, are directly attributable to the quality of the fuel burned and relatively independent of boiler design or operation. Air pollutants affected by burner design and operation are oxidizable materials such as CO, Aldehydes, and unburned hydrocarbons. Nitrogen oxide emissions are more directly related to combustion parameters, primarily temperature. In general, large sources produce more nitrogen oxides than do smaller sources. However, large sources emit fewer aldehydes because of higher temperature and more complete combustion. Evidence suggests that hydrocarbon and carbon monoxide emissions are generally better controlled by larger sources. Table 1.4¹⁸ indicates the relative emission factors by boiler size. Subsequent tables present emissions by fuel quality and boiler size.

Since most state and local regulations are expressed as an emission rate (lbs/10⁶ Btu), the approach used to calculate emissions applies emission factors to various sized oil fuel boilers with known heat rates. Table 1.5 presents residual and distillate oil requirements based on average heat content and density for those fuels. Estimation of more precise fuel requirements can be calculated using specific heat contents and densities (see Appendix B) for fuel from any given source. Once the heat rate has been determined and the fuel input rate calculated, emissions can be estimated by application of the appropriate emission factor.

- *Particulate Emissions from Oil-Fired Steam Generators.* Table 1.6 presents particulate emissions from oil-fueled combustion steam generators. Although modern burners have been designed such that no visible emissions

TABLE 1.4. Emission Factors for Fuel Oil
Combustion Emission Factor Rating: A

Pollutant	Type of Unit - Industrial and Commercial			
	Power Plant	Residual	Distillate	Domestic
	lb/10 ³ gal	lb/10 ³ gal	lb/10 ³ gal	lb/10 ³ gal
Particulate	8	23	15	10
Sulfur dioxide	157S	157S	142S	142S
Sulfur trioxide	2S	2S	2S	2S
Carbon monoxide	3	4	4	5
Hydrocarbons	2	3	3	3
Nitrogen oxides (NO ₂)	105	(40 to 80)	(40 to 80)	12
Aldehydes (HCHO)	1	1	2	2

TABLE 1.5. Fuel Requirements for Oil-Fueled Boilers

Plant Size (MW)	Heat Input 10 ⁶ Btu/hr	Residual gal/hr	Distillate gal/hr
10	103.7	691.3	740.7
20	193.0	1286.7	1378.6
30	285.0	1900.0	2035.7
40	376.0	2506.7	2685.7
50	450.0	3000.0	3214.0
60	534.0	3560.0	3814.0
70	623.0	4153.3	4450.0
80	712.0	4746.7	5085.7
90	801.0	5340.0	5721.4
100	890.0	5933.3	6357.1

should occur, usually noncompatible fuels and burners or improperly adjusted burners will release excessive smoke. Particulate emissions can be subdivided into oxidizable emissions and ash. Oxidizable emissions are controllable through the combustion process, hot ash is more a function of fuel quality. During normal combustion, inorganic ash content of the combustion gas is less

TABLE 1.6. Particulate Emissions from Oil-Fired Boilers

Plant Size (MW)	Residual Oil		Distillate Oil	
	lbs/hr	lbs/10 ⁶ Btu	lbs/hr	lbs/10 ⁶ Btu
10	6.91	.07	7.41	.07
20	12.9	.07	13.8	.07
30	43.7	.15	30.5	.11
40	57.7	.15	40.3	.11
50	69.0	.15	48.2	.11
60	81.9	.15	57.2	.11
70	95.5	.15	66.8	.11
80	38.0	.05	40.7	.06
90	42.7	.05	45.8	.06
100	47.5	.05	50.9	.06

than .1 grain/SCf. When violations of regulations occur, it is the result of the additional component of carbon and oxidizable particulates.¹⁹ As illustrated in Table 1.7, TSP emissions generally remain constant among boiler ranges and fuel types. While total emissions and emissions per unit time increase with size, emissions per unit of heat input (emissions per unit of energy production) remain constant. Implications are that particulate emissions from oil-fueled ICES and from central power stations are an even tradeoff with respect to control of oil particulate emissions. Approximately 98% of the particulate emissions from oil-fired units is less than 5 microns in size, with 85% less than 1 micron.¹⁹ Thus if control is required, only scrubbing or electrostatic precipitation will be effective.

• *Sulfur Dioxide Emissions from Oil-Fired Steam Generators.* Sulfur oxide emissions depend on the quality of oil used. To determine SO₂ emissions, fuel requirements for two general categories of oils were estimated for various size boilers (Table 1.5). Next, emissions were determined for unit size and sulfur content. Conversions have been made to lbs SO₂ emissions/10⁶ Btu to correspond with state and local emission limitations. In large boilers, as much as 5% of the fuels' sulfur is converted to sulfur trioxide. This oxide of sulfur combines with water to form sulfuric acid. However, SO₃ emissions are primarily a problem associated with large boilers operating at high temperatures.

TABLE 1.7. SO₃ Emissions from Oil-Fueled Boilers

Plant Size (MW)	SO ₃ Emissions From Residual Oil										SO ₃ Emissions from Distillate Oil									
	.01% (lbs/hr)	.1% (lbs/hr)	.5% (lbs/hr)	1.0% (lbs/hr)	3.0% (lbs/hr)	.01% (lbs/10 ⁶ Btu)	.1% (lbs/10 ⁶ Btu)	.5% (lbs/10 ⁶ Btu)	1.0% (lbs/10 ⁶ Btu)	3.0% (lbs/10 ⁶ Btu)	.01% (lbs/hr)	.1% (lbs/hr)	.5% (lbs/hr)	1.0% (lbs/hr)	3.0% (lbs/hr)	.01% (lbs/10 ⁶ Btu)	.1% (lbs/10 ⁶ Btu)	.5% (lbs/10 ⁶ Btu)	1.0% (lbs/10 ⁶ Btu)	3.0% (lbs/10 ⁶ Btu)
10	.014	.138	.691	1.38	4.15	.0001	.001	.007	.013	.040	.015	.148	.741	1.48	4.44	.0001	.001	.007	.014	.043
20	.026	.257	1.29	2.57	7.72	.0001	.001	.007	.013	.040	.028	.276	1.38	2.76	8.27	.0001	.001	.007	.014	.043
30	.038	.380	1.90	3.80	11.4	.0001	.001	.007	.013	.040	.041	.407	2.04	4.07	12.2	.0001	.001	.007	.014	.043
40	.050	.501	2.51	5.01	15.0	.0001	.001	.007	.013	.040	.054	.537	2.69	5.37	16.1	.0001	.001	.007	.014	.043
50	.060	.600	3.00	6.00	18.0	.0001	.001	.007	.013	.040	.064	.643	3.21	6.43	19.3	.0001	.001	.007	.014	.043
60	.071	.712	3.56	7.12	21.4	.0001	.001	.007	.013	.040	.076	.763	3.81	7.63	22.9	.0001	.001	.007	.014	.043
70	.083	.831	4.15	8.31	24.9	.0001	.001	.007	.013	.040	.089	.890	4.45	8.90	26.7	.0001	.001	.007	.014	.043
80	.095	.949	4.75	9.49	28.5	.0001	.001	.007	.013	.040	.102	1.02	5.09	10.2	30.5	.0001	.001	.007	.014	.043
90	.107	1.07	5.34	10.7	32.0	.0001	.001	.007	.013	.040	.114	1.14	5.72	11.4	34.3	.0001	.001	.007	.014	.043
100	.119	1.19	5.93	11.9	35.6	.0001	.001	.007	.013	.040	.127	1.27	6.36	12.7	38.1	.0001	.001	.007	.014	.043

They are the main cause of visible emissions from oil-fueled steam generators. Visible emissions occur when SO_3 reacts with moisture in the air to form a sulfuric acid aerosol. Fine particulates further contribute to condensation by providing a nuclei for droplet formation. Because SO_2 emissions are directly proportional to the sulfur content of the fuel and to the boiler design, emissions (while increasing in absolute terms) remain constant when expressed in terms of unit of energy generated. Table 1.7 presents SO_3 emissions from oil-fired boilers, and Table 1.8 presents SO_2 emissions.

- *Oxides of Nitrogen from Oil-Fired Steam Generators.* Nitrogen oxide emissions from oil-fired steam generators include NO_2 , NO , N_2O_4 , N_2O_5 , and NO_3 . However, NO and NO_2 are the prime constituents of stack gas and are the two oxides of nitrogen important to consider as air pollutants. Of the 22.8 million tons of nitrogen oxides emitted in 1970, about 10 million came from stationary source fuel combustion. Of that 10 million tons, about 1.3 million tons came from oil-fueled sources. Although oil steam generators are not the prime source of NO_x , they do contribute heavily to the problem and are subject to NO_x emission regulations.

Nitric oxide in itself is not a significant health hazard. Formation of this oxide is favored at high temperatures. For example, at 200°F the equilibrium concentration of nitric oxide is 180 ppm but at 2800°F the equilibrium concentration jumps to 1380 ppm. At 3600°F the equilibrium concentration is 4150 ppm. The problem with high concentrations of NO is that over 100 ppm significant amounts of NO_2 are formed. NO_2 is a highly corrosive and toxic gas.

The NO oxides forming NO_3 combine with NO to form NO_2 . Sunlight and hydrocarbons will additionally convert NO to NO_2 . Because of high temperature formation of NO , larger boilers operating at higher temperatures emit more NO and NO_2 .¹⁹

Unlike sulfur dioxide, the oxides of nitrogen are not as fuel-dependent as they are boiler size dependent. Small boilers have ten times better emissions per unit of energy produced and almost 100 times better absolute emission rates.

TABLE 1.8. SO₂ Emissions from Oil-Fueled Boilers

Plant Size (MW)	SO ₂ Emissions From Residual Oil										SO ₂ Emissions From Distillate Oil									
	.01% (lbs/hr)	.1% (lbs/hr)	.5% (lbs/hr)	1.0% (lbs/hr)	3.0% (lbs/hr)	.01% (lbs/10 ⁶ Btu)	.1% (lbs/10 ⁶ Btu)	.5% (lbs/10 ⁶ Btu)	1.0% (lbs/10 ⁶ Btu)	3.0% (lbs/10 ⁶ Btu)	.01% (lbs/hr)	.1% (lbs/hr)	.5% (lbs/hr)	1.0% (lbs/hr)	3.0% (lbs/hr)	.01% (lbs/10 ⁶ Btu)	.1% (lbs/10 ⁶ Btu)	.5% (lbs/10 ⁶ Btu)	1.0% (lbs/10 ⁶ Btu)	3.0% (lbs/10 ⁶ Btu)
10	.98	9.82	49.1	98.2	294.5	.009	.09	.47	.95	2.84	1.05	10.5	52.6	105.2	315.5	.01	.10	.51	1.01	3.04
20	1.83	18.3	91.4	182.7	584.1	.009	.09	.47	.95	2.84	1.96	19.6	97.9	195.8	587.3	.01	.10	.51	1.01	3.04
30	2.98	29.8	149.3	298.3	894.9	.01	.10	.52	1.05	3.14	2.89	28.9	144.5	289.1	867.2	.01	.10	.51	1.01	3.04
40	3.94	39.4	196.8	393.6	1180.7	.01	.10	.52	1.05	3.14	3.81	38.1	190.7	381.4	1144.1	.01	.10	.51	1.01	3.04
50	4.71	47.1	235.5	471.0	1413.0	.01	.10	.52	1.05	3.14	4.56	45.6	228.2	456.4	1369.3	.01	.10	.51	1.01	3.04
60	5.59	55.9	279.5	558.9	1676.8	.01	.10	.52	1.05	3.14	5.42	54.2	270.8	541.6	1624.9	.01	.10	.51	1.01	3.04
70	6.52	65.2	326.0	652.1	1956.2	.01	.10	.52	1.05	3.14	6.32	63.2	316.0	631.9	1895.7	.01	.10	.51	1.01	3.04
80	7.45	74.5	372.6	745.2	2235.7	.01	.10	.52	1.05	3.14	7.98	79.8	399.2	798.5	2395.4	.01	.11	.56	1.12	3.36
90	8.38	83.8	419.2	838.4	2515.1	.01	.10	.52	1.05	3.14	8.98	89.8	449.1	898.3	2694.8	.01	.11	.56	1.12	3.36
100	9.32	93.2	465.8	931.5	2794.6	.01	.10	.52	1.05	3.14	9.98	99.8	499.0	998.1	2994.2	.01	.11	.56	1.12	3.36

Table 1.9 illustrates NO₂ emissions by boiler size and general fuel use category.

TABLE 1.9. NO₂ Emissions from Oil-Fueled Boilers

Plant Size (MW)	NO ₂ Emissions from Residual Oil		NO ₂ Emissions from Distillate Oil	
	lbs/hr	lbs/10 ⁶ Btu	lbs/hr	lbs/10 ⁶ Btu
10	8.3	.08	8.89	.09
20	15.4	.08	16.5	.09
30	76.0 -	.27 -	81.4 -	.29 -
	152.0	.53	162.9	.57
40	100.3 -	.27 -	107.4 -	.29 -
	200.5	.53	214.9	.57
50	120.0 -	.27 -	128.6 -	.29 -
	240.0	.53	257.1	.57
60	142.4 -	.27 -	152.6 -	.29 -
	284.8	.53	305.1	.57
70	166.1 -	.27 -	178.0 -	.29 -
	332.3	.53	356.0	.57
80	498.4	.70	534.0	.75
90	560.7	.70	600.7	.75
100	623.0	.70	677.5	.75

Note: For plant sizes where a range is shown for emissions, the lower end is for tangentially fired units and the higher end is for horizontally fired units.

• *Hydrocarbon Emissions from Oil Fired Steam Generators.* Hydrocarbon emission refers to a broad group of compounds containing only hydrogen and carbon atoms. Stationary oil-fueled combustion processes account for only .3% of total national emissions. The potential for environmental degradation is not so much in the emission of hydrocarbons but rather is the presence of hydrocarbons in the atmosphere. Hydrocarbon compounds react in photochemical reactions to produce irritating and hazardous compounds such as NO₂ or smog. In an attempt to inhibit NO₂ and smog production, many communities have restricted hydrocarbon emissions. As shown in Table 1.10 hydrocarbon emissions from oil-fueled boilers do not present significant problems with respect to meeting environmental standards. Emission rates, are slightly lower per unit

of energy produced for larger boilers, but the amounts are not significant to favor large or small boilers.

TABLE 1.10. Hydrocarbon Emissions from Oil-Fueled Boilers

Plant Size (MW)	Residual Oil		Distillate Oil	
	lbs/hr	lbs/10 ⁶ Btu	lbs/hr	lbs/10 ⁶ Btu
10	2.07	.02	2.22	.02
20	3.86	.02	4.14	.02
30	5.70	.02	6.11	.02
40	7.52	.02	8.06	.02
50	9.00	.02	9.64	.02
60	10.68	.02	11.44	.02
70	12.46	.02	13.35	.02
80	9.49	.01	10.17	.01
90	10.68	.01	11.44	.01
100	11.87	.01	12.71	.01

• *Carbon Monoxide Emissions from Oil-Fired Steam Generators.* Carbon monoxide (CO) is a product of incomplete combustion. Although natural decay of organic matter accounts for about 80% of the earth's CO, increasing levels of ambient CO have caused concern that industrialization is contributing to a global imbalance of CO. Local concentrations of CO in urban, industrialized areas are as much as ten times higher than ambient concentrations.

In the case of oil-fueled steam generators, CO results from incomplete combustion, so proper boiler design and operation can eliminate any significant CO emission problems. Table 1.11 illustrates the low levels of CO emissions from oil-fueled steam generators.

TABLE 1.11. CO Emissions from Oil-Fueled Boilers

Plant Size (MW)	Residual Oil		Distillate Oil	
	lbs/hr	lbs/10 ⁶ Btu	lbs/hr	lbs/10 ⁶ Btu
10	3.46	.03	3.70	.04
20	6.43	.03	6.89	.04
30	0.38	.001	0.41	.001
40	0.50	.001	0.54	.001
50	0.60	.001	0.64	.001
60	0.71	.001	0.76	.001
70	0.83	.001	0.89	.001
80	0.19	.0003	0.20	.0003
90	0.21	.0003	0.23	.0003
100	0.24	.0003	0.25	.0003

• *Aldehyde Emissions from Oil-Fired Steam Generators.* Aldehyde emissions from steam generators occur at very low levels and do not present significant regulatory problems. Table 1.12 presents aldehyde emission rates from oil-fueled steam generators.

• *Water and Noise Emissions from Oil-Fired Steam Generators.* Water and noise emissions from oil-fired boilers are similar to those from coal-fired units. Water and noise emissions are discussed in that section.

• *Emissions from Gas-Fired Steam Generators.* Natural-gas-fired steam generators provide, by far, the maximum energy with minimum environmental degradation. Commercial gas burners include simple atmospheric gas burners generally used on boilers up to about 20×10^6 Btu/hr input. These simple, domestic boilers operate on from 1/2 oz to 5 lbs gas pressure, although normal operating pressures are about 4 oz to 1 lb. Upshot or inshot burners are relatively maintenance free. The upshot burner usually is used to replace coal burners in old fire boxes and rotary cup oil burners.¹⁹ As shown in Table 1.13, particulate, SO₂, CO, and hydrocarbon emissions are relatively low. NO_x emissions are within tolerable limits as shown in Table 1.14.

TABLE 1.12. Aldehyde Emissions from Oil-Fired Boilers

Plant Size (MW)	Residual Oil		Distillate Oil	
	lbs/hr	lbs/10 ⁶ Btu	lbs/hr	lbs/10 ⁶ Btu
10	1.38	.01	1.48	.01
20	2.57	.01	2.76	.01
30	1.90	.007	4.07	.01
40	2.51	.007	5.37	.001
50	3.00	.007	6.43	.01
60	3.56	.007	7.63	.01
70	4.15	.007	8.90	.01
80	4.75	.007	5.09	.007
90	5.34	.007	5.72	.007
100	5.93	.007	6.36	.007

Power gas burners generally are used for boilers in the 60×10^3 Btu/hr to 20×10^6 Btu/hr category. Power burners operate at slightly higher pressures than do atmospheric burners. Added turbulence in the burner throat results in more rapid combustion. Higher firing rates result in higher temperatures and NO₂ emissions. Particulate, CO, and SO₂ emissions remain constant while more complete combustion actually lowers emissions of unburned hydrocarbons.

The largest gas burners are gun type, ring type, or multispud large in-shot raw gas burners. Gas pressures of 15 to 50 lbs are used. Of the three burner designs, the ring type uses pressures of 5-20 lbs, whereas, the gun and multispot types often operate at higher gas pressures. Large burners of this type generally are acceptable for multifuel firing and are usually used in boilers requiring between 15 and 300×10^6 Btu/hr heat input per burner. From 1 to 40 burners may be used in a boiler. Although high temperature combustion maintains low emission rates for particulates, SO₂, CO, and unburned hydrocarbons, NO₂ emissions become troublesome at high temperature. As much as 600 lb/10⁶ ft³ of NO₂ emissions can cause NO_x violations under certain operating conditions.

- *Water and Noise Emissions from Gas-Fired Steam Generators.* As is the case of air-fired steam generators, gas-fired steam generators have boiler feed and blowdown water quality problems similar to coal steam generations. Noise

TABLE 1.13. Particulate and Sulfur Dioxide Emissions from Gas-Fired Boilers

Plant Size (MW)	PM Emissions		SO ₂ Emissions	
	lbs/hr	lbs/10 ⁶ Btu	lbs/hr	lbs/10 ⁶ Btu
10	.49 -	.005 -	.06	.0006
	1.48	.014		
20	.92 -	.005 -	.11	.0006
	2.76	.014		
30	1.36 -	.005 -	.16	.0006
	4.07	.014		
40	1.79 -	.005 -	.21	.0006
	5.37	.014		
50	2.14 -	.005 -	.26	.0006
	6.43	.014		
60	2.54 -	.005 -	.31	.0006
	7.63	.014		
70	2.97 -	.005 -	.36	.0006
	8.90	.014		
80	3.39 -	.005 -	.41	.0006
	10.17	.014		
90	3.81 -	.005 -	.46	.0006
	11.44	.014		
100	4.24 -	.005 -	.51	.0006
	12.71	.014		

TABLE 1.14 Carbon Monoxide, Hydrocarbon and Nitrogen Dioxide Emissions from Gas-Fired Boilers

PLANT SIZE (MW)	CO EMISSIONS		HC EMISSIONS		NO ₂ EMISSIONS	
	lb/hr	lb/10 ⁶ Btu	lb/hr	lb/10 ⁶ Btu	lb/hr	lb/10 ⁶ Btu
10	1.98	.019	.79	.008	7.90 11.85	.076 (Domestic Units) .114 (Commercial Units)
20	3.68	.019	1.47	.008	14.70 22.06	.076 (Domestic Units) .114 (Commercial Units)
30	4.61	.016	.81	.003	32.57- 62.43	.114- .219
40	6.09	.016	1.07	.003	42.97- 82.36	.114- .219
50	7.29	.016	1.29	.003	51.43- 98.57	.114- .219
60	8.65	.016	1.53	.003	61.03- 116.97	.114- .219
70	10.09	.016	1.78	.003	71.20- 136.47	.114- .219
80	11.53	.016	.68	.001	474.67 203.43	.667 .286 (Tangentially fired units)
90	12.97	.016	.76	.001	534.00 228.86	.667 .286 (Tangentially fired units)
100	14.41	.016	.85	.001	593.33 254.29	.667 .286 (Tangentially fired units)

emissions are also similar with the exception of coal mills required for pulverized plants.

- *Emissions from Coal-Fired Steam Generators.* Coal-fired steam generators are characterized as underfeed stokers and spreader stokers. Pulverized coal-firing units include wet and dry bottom designs and cyclone furnaces. Each of these designs has features that affect particulate and NO₂ emissions. CO and hydrocarbon emissions are increased when designs do not promote complete combustion. SO₂ emissions remain constant across all boiler designs.

Residential underfeed stokers generally are single retort. Coal is conveyed by a screw to the retort. Air is blown through grate openings, and ash is removed by hand through the firing door. Generally, these units are used in units ranging from 1 to 60 lbs/hr of coal input. Larger multiple retort underfeed stokers burn from 60 to 1,200 lbs of coal per hour (9.6×10^6 Btu/hr heat input). Sizes of these units range from 20,000 to 500,000 lbs of steam per hour. Multiple retorts with screw coal conveyance supplies fuel to the firing zone. Air is supplied from beneath the grate, and ash generally is worked from a front hopper to a ream ash discharge unit using "pushers." The combustion process in the underfeed stoker, although unsophisticated, provides the operation with a fair degree of control. Resultant particulate CO and hydrocarbon may be high. If the unit is not properly operated, quality regulations are violated during periods of improper operation or startup. Vibrating and traveling grate burners generally are replacing the multiple retort boilers for generation of steam in the 5,000 to 10,000 lb/hr range. The primary difference between these units is that the fuel is conveyed across the grate automatically by a vibrating mechanism or through a traveling grate. The coal burns as it travels and finally is conveyed to a discharge mechanism. Most package boilers utilize the moving grate design.²⁰

Spreader stokers are designed to burn coal in an air suspension and on a traveling grate. A flipper mechanism tosses the fuel into the burning zone where it combusts under carefully regulated conditions. Low burning rates can result in high particulate emissions; incomplete fuel combustion could cause excessive hydrocarbon loss. Spreader stokers are popular in the 6 to 500×10^6 Btu/hr heat input range generating anywhere from 5,000 to 400,000 pounds of steam per hour.

Pulverized-fuel-fired units usually are referred to as wet or dry bottom boilers. In this system, coal is pulverized to pass through a 200 mesh sieve. Burners are characterized by their firing position (vertical, horizontal, or tangential). In wet bottom boilers, the temperature is maintained above the ash fusion temperature. The slag is melted and removed from the bottom of the boiler as a liquid. The dry bottom boiler operates at lower temperatures such that the ash does not fuse and is removed as a solid ash. The net result of these two types of boiler design is higher NO₂ emissions from the high temperature, wet bottom boiler and higher particulate emissions from the dry bottom design. Pulverized fuel boilers operate from about 200,000 to several million pounds of steam per hour.

The cyclone furnace is the largest coal steam generator heat source. It consists of a water-cooled horizontal cyclinder in which fuel is fired and heat released at an extremely high rate. Coal, pulverized to pass a 4 mesh screen, is then introduced at the burner end of the cyclone. Air is admitted tangentially. The result is a high-temperature cyclone with ash being discharged as a liquid and hot gases leaving the end of the cylinder. Cyclone furnaces are advantageous from a viewpoint of particulate emissions. Emissions are 6 to 8 times less than from comparable pulverized coal units. Associated with high temperature operation, however, NO₂ emissions are 2 to 4 times higher than comparable pulverized coal unit designs.¹⁹

To estimate airborne emissions associated with coal-fired boilers, a regionalization of fuel and subdivision by boiler type was necessary. Table 1.15 characterizes coal from the five major domestic coal supply areas. Only bituminous and subbituminous coals are included in the analysis. Anthracite or metalurgical coal, while having high heat content and relatively low levels of impurities, is expensive and not likely to be used in power production. Lignite, on the other end of the scale, has such a low heat content and poor burning qualities that it is also excluded from the analysis. Although only five types of regional fuels are discussed, other possibilities for coal utilization exist; these include coal liquifaction, washing, and gasification. Coal pretreatment is a separate subject and will be discussed independently.

Table 1.16 presents coal combustion emission factors that are applicable to boiler fuel requirements for various boiler sizes and designs. As previously discussed, boiler design has considerable effect on particulate emis-

TABLE 1.15. Regional Coal Analysis³

Region	Caloric Content (Btu/lb)	Sulfur Content (% by wt)	Ash Content (% by wt)	Coal Density (lb/cf)	Coal Type
Northwest (Powder River Basin)	8,780	0.85	6.77	81	Subbituminous
Central (IL and IN)	10,600	2.92	8.9	81	Bituminous
North Appalachia (Central and Western PA and OH)	11,800	3.07	14.7	85	Bituminous
Central Appalachia (Southern WV, VA, and Eastern KY)	12,100	0.93	11.2	85	Bituminous
Southwest (NM, particularly San Juan Basin)	9,820	0.6	15.7	81	Subbituminous
National Average of Coal Consumed (1971)	12,180	2.59	12.53	81	

Source: Reference 21

sions and products of combustion such as CO, oxides of nitrogen, and unburned hydrocarbons. Aldehyde emissions remain at constant levels and do not appear to present environmental problems. Emissions of carbon monoxide and hydrocarbons are directly related to the combustion process. Larger burners having better combustion characteristics tend to have reduced emission rates; whereas, simple designs, such as the spreader stoker and underfeed stoker have high CO and hydrocarbon emissions. Although particulate emissions are a function of fuel ash content, they also depend on the design of the burning zone. Cyclones and wet bottom boilers which liquify the ash significantly reduce particulate emissions. Designs using liquified beds and operating at high temperatures have NO₂ emission problems existent with all high-temperature, fossil-fuel combustion. Emission factors in Table 1.16 are applied to fuel requirements for each boiler size and design listed in Table 1.17 to yield pollutants by size, boiler design, and fuel type.

Table 1.18 presents particulate emissions by boiler size and design and fuel use. As illustrated, southwestern coal having 15% ash content emits extremely large amounts of particulates. Contrasting particulate emissions using

TABLE 1.16. Coal Combustion Emission Factors¹⁸

Unit Type	Emission Factors (lbs/ton of coal burned)					
	Particulates	SO ₂	CO	NO _x	HC	Aldehydes
Underfeed Stoker	2(A)	38(S)	10	6	3	.005
Spreader Stoker	13(A)	38(S)	2	15	1	.005
Wet Bottom Boiler	13(A)	38(S)	1	30	.3	.005
Dry Bottom Boiler	17(A)	38(S)	1	18	.3	.005
Cyclone	2(A)	38(S)	1	55	.3	.005

A = Ash Contents; S = Sulfur Contents

southwestern coal with emissions burning northwestern coal shows a reduction of 50% in particulate emissions.

SO₂ emissions are presented in Table 1.19. As in the case of particulate emissions, SO₂ discharges are directly proportional to the quality of the fuel. In the case of SO₂, boiler design is not a factor in the release of sulfur from burning coal.

Carbon monoxide emissions as shown in Table 1.20 are dramatically reduced by improving boiler design to promote complete combustion. For example, a 100-MW cyclone steam plant will emit carbon monoxide at the same rate as a 20-MW spreader stoker and much less than a 10-MW underfeed stoker.

Nitrogen oxide emissions as previously discussed, are highly dependent on combustion temperatures. As shown in Table 1.21, cyclone and wet bottom boilers have significantly higher NO₂ emissions and are subject to state and local regulation.

Table 1.22 presents boiler aldehyde emissions and indicates that northwestern, central, and southwestern coal show more potential for aldehyde emissions. Emission levels are sufficiently low and do present a control problem.

Hydrocarbon emissions, as shown in Table 1.23, improve with the combustion process. Levels are sufficiently low, such that emission control for this pollutant by itself is not necessary.

TABLE 1.17. Fuel Use for Coal Burning Combustion Equipment

Plant Size (MW)	Type of Unit	Heat Input Required (10^6 Btu/hr)	Fuel Use Required by Regional Coal Type (t/hr)				
			Northwest	Central	N. Appalachia	C. Appalachia	Southwest
10	SS US	103.7	5.91	4.89	4.39	4.29	5.28
20	SS US	193.0	10.99	9.10	8.18	7.98	9.83
30	SS US	285.0	16.23	13.44	12.08	11.78	14.51
40	SS US	376.0	21.41	17.74	15.93	15.54	19.14
50	SS, WB US, C DB	450.0	25.63	21.23	19.07	18.60	22.91
60	SS, WB C DB	534.0	30.41	25.19	22.63	22.07	27.19
70	WB C DB	623.0	35.48	29.39	26.40	25.74	31.72
80	WB C DB	712.0	40.55	33.58	30.17	29.42	36.25
90	WB C DB	801.0	45.62	37.78	33.94	33.10	40.78
100	WB C DB	890.0	50.68	41.98	37.71	36.78	45.32

SS - Spreader Stoker

US - Underfeed Stoker

WB - Wet Bottom Boiler

DB - Dry Bottom Boiler

C - Cyclone

TABLE 1.18. Particulate Emissions from Coal Burning Combustion Equipment

Particulate Emissions by Regional Coal Type						
Plant Size (MW)	Type of Unit	Northwest lbs/hr	Central lbs/hr	N. Appalachia lbs/hr	C. Appalachia lbs/hr	Southwest lbs/hr
10	Spreader Stokers	517.7	565.9	839.7	623.9	1077.6
	Underfeed Stokers	80.0	87.1	129.2	96.0	165.8
20	Spreader Stokers	967.3	1053.3	1562.8	1161.2	2005.7
	Underfeed Stokers	148.8	162.0	240.4	178.6	308.6
30	Spreader Stokers	1428.4	1555.4	2307.8	1714.7	2961.7
	Underfeed Stokers	219.8	239.3	355.0	263.8	455.7
40	Spreader Stokers	1884.5	2052.0	3044.6	2262.2	3907.4
	Underfeed Stokers	289.9	315.7	468.4	348.0	601.1
50	Spreader Stokers					
	Wet Bottom Boilers	2255.4	2455.9	3643.9	2707.4	4676.4
	Underfeed Stokers					
	Cyclone Boilers	347.0	377.8	560.6	416.5	719.4
60	Dry Bottom Boilers	2949.3	3211.6	4765.0	3540.5	6115.3
	Spreader Stokers					
	Wet Bottom Boilers	2676.4	2914.3	4324.0	3212.8	5549.4
	Cyclone Boilers	411.8	448.4	665.2	494.3	853.7
70	Dry Bottom Boilers	3499.9	3811.1	5654.5	4201.4	7256.9
	Wet Bottom Boilers	3122.5	3400.1	5044.7	3748.3	6474.3
	Cyclone Boilers	480.4	523.1	776.1	576.7	996.0
	Dry Bottom Boilers	4083.2	4446.2	6596.9	4901.6	8466.3
80	Wet Bottom Boilers	3568.5	3885.8	5765.4	4283.8	7399.1
	Cyclone Boilers	549.0	597.8	887.0	659.0	1138.3
	Dry Bottom Boilers	4666.5	5081.4	7539.4	5601.9	9675.8
90	Wet Bottom Boilers	4014.6	4371.5	6486.1	4819.2	8324.0
	Cyclone Boilers	617.6	672.5	997.9	741.4	1280.6
	Dry Bottom Boilers	5249.8	5716.6	8481.8	6302.1	10885.3
100	Wet Bottom Boilers	4460.6	4857.2	7206.7	5354.7	9248.9
	Cyclone Boilers	686.3	747.3	1108.7	823.8	1422.9
	Dry Bottom Boilers	5833.2	6351.7	9424.2	7002.3	12094.8

TABLE 1.19. SO₂ Emissions by Regional Coal Type

<u>Plant Size</u> (MW)	<u>Type of Unit</u>	<u>Heat Input Required</u> (10 ⁶ Btu/hr)	<u>Northwest</u> lbs/hr	<u>Central</u> lbs/hr	<u>N. Appalachia</u> lbs/hr	<u>C. Appalachia</u> lbs/hr	<u>Southwest</u> lbs/hr
10	SS,US	103.7	190.9	542.6	512.1	151.6	120.4
20	SS,US	193.0	355.0	1009.7	954.3	282.0	224.1
30	SS,US	285.0	524.2	1491.3	1409.3	416.3	330.8
40	SS,US	376.0	691.5	1968.4	1858.4	549.2	436.4
50	SS,WB, US,C, DB	450.0	827.8	2355.7	2224.7	657.3	522.3
60	SS,WB, C,DB	534.0	982.2	2795.1	2640.0	780.0	619.9
70	WB,C, DB	623.0	1146.0	3261.1	3079.8	909.7	723.2
80	WB,C, DB	712.0	1309.8	3726.0	3519.6	1039.7	826.5
90	WB,C, DB	801.0	1473.5	4198.1	3959.4	1169.8	929.8
100	WB,C, DB	890.0	1637.0	4658.1	4399.2	1299.8	1033.3

TABLE 1.20: CO Emissions by Regional Coal Type

<u>Plant Size (MW)</u>	<u>Type of Unit</u>	<u>Heat Input Required (10⁶ Btu/hr)</u>	<u>Northwest lbs/hr</u>	<u>Central lbs/hr</u>	<u>N. Appalachia lbs/hr</u>	<u>C. Appalachia lbs/hr</u>	<u>Southwest lbs/hr</u>
10	SS	103.7	11.8	9.8	8.8	8.6	10.6
	US		59.1	48.9	43.9	42.9	52.8
20	SS	193.0	22.0	18.2	16.4	16.0	19.7
	US		109.9	91.0	81.8	79.8	98.3
30	SS	285.0	32.5	26.9	24.2	23.6	29.0
	US		162.3	134.4	120.8	117.8	145.1
40	SS	376.0	42.8	35.5	31.9	31.1	38.3
	US		214.1	177.4	159.3	155.4	191.4
50	SS	450.0	51.3	42.5	38.1	37.2	45.8
	US		256.3	212.3	190.7	186.0	229.1
	WB,DB,C		12.8	10.6	9.5	9.3	11.5
60	SS	534.0	60.8	50.4	45.3	44.1	54.4
	WB,DB,C		15.2	12.6	11.3	11.0	13.6
70	WB,DB,C	623.0	17.7	14.7	13.2	12.9	15.9
80	WB,DB,C	712.0	20.3	16.8	15.1	14.7	18.1
90	WB,DB,C	801.0	22.8	18.9	17.0	16.6	20.4
100	WB,DB,C	890.0	25.3	21.0	18.9	18.4	22.7

TABLE 1.21. NO_x Emissions by Regional Coal Type

Plant Size (MW)	Type of Unit	Heat Input Required (10 ⁶ Btu/Hr)	Northwest lbs/hr	Central lbs/hr	N. Appalachia lbs/hr	C. Appalachia lbs/hr	Southwest lbs/hr
10	SS	103.7	88.7	73.4	65.9	64.4	79.2
	US		35.5	29.3	26.3	25.7	31.7
20	SS	193.0	164.9	136.5	122.7	119.7	147.5
	US		65.9	54.6	49.1	47.9	59.0
30	SS	285.0	243.5	201.6	181.2	176.7	217.7
	US		97.4	80.6	72.5	70.7	87.1
40	SS	376.0	321.2	266.1	239.0	233.1	287.1
	US		128.5	106.4	95.6	93.2	114.8
50	SS	450.0	384.5	318.5	286.1	279.0	343.7
	US		153.8	127.4	114.4	111.6	137.5
	WB		768.9	636.9	572.1	558.0	687.3
	DB		461.3	382.1	343.3	334.8	412.4
	C		1409.7	1167.7	1048.9	1023.0	1260.1
60	SS	534.0	456.2	377.9	339.5	331.1	407.9
	WB		912.3	755.7	678.9	662.1	815.7
	DB		547.4	453.4	407.3	397.3	489.4
	C		1672.6	1385.5	1244.7	1213.9	1495.5
70	WB	623.0	1064.4	881.7	792.0	771.0	951.6
	DB		638.6	529.0	475.2	462.6	571.0
	C		1951.4	1616.5	1452.0	1413.5	1744.6
80	WB	712.0	1216.5	1007.4	905.1	882.6	1087.5
	DB		729.9	604.4	543.1	529.6	652.5
	C		2230.3	1846.9	1659.4	1618.1	1993.8
90	WB	801.0	1368.6	1133.4	1018.2	993.0	1223.4
	DB		821.2	680.0	610.9	595.8	734.0
	C		2509.1	2077.9	1866.7	1820.5	2242.9
100	WB	890.0	1520.4	1259.4	1131.3	1103.4	1359.6
	DB		912.2	755.6	678.8	662.0	815.8
	C		2787.4	2308.9	2074.1	2022.9	2492.6

TABLE 1.22. Aldehydes Emissions by Regional Coal Type

Plant Size (MW)	Type of Unit	Heat Input Required (10 ⁶ Btu/hr)	Northwest lbs/hr	Central lbs/hr	N. Appalachia lbs/hr	C. Appalachia lbs/hr	Southwest lbs/hr
10	SS,US	103.7	.030	.024	.022	.021	.026
20	SS,US	193.0	.055	.046	.041	.040	.049
30	SS,US	285.0	.081	.067	.060	.059	.073
40	SS,US	376.0	.107	.089	.080	.078	.096
50	SS,US, WB,DB, C	450.0	.128	.106	.095	.093	.115
60	SS WB,DB, C	534.0	.152	.126	.113	.110	.136
70	WB,DB, C	623.0	.177	.147	.132	.129	.159
80	WB,DB, C	712.0	.203	.168	.151	.147	.181
90	WB,DB, C	801.0	.228	.189	.170	.166	.204
100	WB,DB, C	890.0	.253	.210	.189	.184	.227

TABLE 1.23. HC Emissions by Regional Coal Type

<u>Plant Size (MW)</u>	<u>Type of Unit</u>	<u>Heat Input Required (10⁶ Btu/hr)</u>	<u>Northwest lbs/hr</u>	<u>Central lbs/hr</u>	<u>N. Appalachia lbs/hr</u>	<u>C. Appalachia lbs/hr</u>	<u>Southwest lbs/hr</u>
10	SS	103.7	5.9	4.9	4.4	4.3	5.3
	US		17.7	14.7	13.2	12.9	15.8
20	SS	193.0	11.0	9.1	8.2	8.0	9.8
	US		33.0	27.3	24.5	23.9	29.5
30	SS	285.0	16.2	13.4	12.1	11.8	14.5
	US		48.7	40.3	36.2	35.3	43.5
40	SS	376.0	21.4	17.7	15.9	15.5	19.1
	US		64.2	53.2	47.8	46.6	57.4
50	SS	450.0	25.6	21.2	19.1	18.6	22.9
	US		76.9	63.7	57.2	55.8	68.7
	WB,DB,C		7.7	6.4	5.7	5.6	6.9
60	SS	534.0	30.4	25.2	22.6	22.1	27.2
	WB,DB,C		9.1	7.6	6.8	6.6	8.2
70	WB,DB,C	623.0	10.6	8.8	7.9	7.7	9.5
80	WB,DB,C	712.0	12.2	10.1	9.1	8.8	10.9
90	WB,DB,C	801.0	13.7	11.3	10.2	9.9	12.2
100	WB,DB,C	890.0	15.2	12.6	11.3	11.0	13.6

The final table, 1.24, summarizes pollutant emissions for coal boilers and converts emissions to lbs/10⁶ Btu. Because most state and local performance regulations are based on pollutant emission rate by unit of heat input, this conversion is necessary before regulatory comparisons can be made.

• *Noise and Water Quality Considerations.* Although estimation of noise emissions from prime movers is difficult, it is nevertheless important in ICES design and construction. Noise emissions are likely to occur during construction of the prime mover and during operation of certain prime mover auxiliary equipment. Auxiliary equipment associated with coal-fired prime movers include coal mills for pulverized boilers, boiler feed pumps, forced-draft fans, induced-draft fans, pressure-reducing stations, demineralizers, and flue dust exhaust equipment. If cooling towers are used in a particular ICES design, they too are a prime source of noise emissions. Additional sources of noise may occur during boiler blowoff and transmission of electrical current. Table 1.25 itemizes coal-fired boiler noise levels in dba.

TABLE 1.25. Typical Coal-Fired Boiler Equipment Noise Emission Levels

Activity	Noise Levels (dba)
Construction Noise	
Site preparation	50
Steel/concrete work	40
Operation of coal mills	86-100
Boiler feed pumps	85-99.5
Forced draft fans	85-109.5
Induced draft fans	76.5-97
Pressure reducing stations	82-109
Demineralizers	85-101
Flue dust exhausters	85-103
Cooling tower operation	55

TABLE 1.24. Emissions from Coal Combustion Sources

	Particulate Emissions lbs/10 ⁶ Btu	SO ₂ lbs/10 ⁶ Btu	CO lbs/10 ⁶ Btu	NO ₂ lbs/10 ⁶ Btu	HC lbs/10 ⁶ Btu	Aldehydes lbs/10 ⁶ Btu
<u>Northwestern Coal</u>						
Underfeed Stokers	.77	1.84	.57	.34	.17	.0003
Spreader Stokers	5.01	1.84	.11	.85	.06	.0003
Wet Bottom Boilers	5.01	1.84	.03	1.71	.02	.0003
Dry Bottom Boilers	6.55	1.84	.03	1.03	.02	.0003
Cyclone Boilers	.77	1.84	.03	3.13	.02	.0003
<u>Central Coal</u>						
Underfeed Stokers	.84	5.23	.47	.28	.14	.0002
Spreader Stokers	5.46	5.23	.09	.71	.05	.0002
Wet Bottom Boilers	5.46	5.23	.02	1.42	.01	.0002
Dry Bottom Boilers	7.14	5.23	.02	.85	.01	.0002
Cyclone Boilers	.84	5.23	.02	2.59	.01	.0002
<u>Northern Appalachian</u>						
Underfeed Stokers	1.25	4.94	.42	.25	.13	.0002
Spreader Stokers	8.10	4.94	.08	.64	.04	.0002
Wet Bottom Boilers	8.10	4.94	.02	1.27	.01	.0002
Dry Bottom Boilers	10.59	4.94	.02	.76	.01	.0002
Cyclone Boilers	1.25	4.94	.02	2.33	.01	.0002
<u>Central Appalachian</u>						
Underfeed Stokers	.93	1.46	.41	.25	.12	.0002
Spreader Stokers	6.02	1.46	.08	.62	.04	.0002
Wet Bottom Boilers	6.02	1.46	.02	1.24	.01	.0002
Dry Bottom Boilers	7.87	1.46	.02	.74	.01	.0002
Cyclone Boilers	.93	1.46	.02	2.27	.01	.0002
<u>Southwestern Coal</u>						
Underfeed Stokers	1.60	1.16	.51	.31	.15	.0003
Spreader Stokers	10.39	1.16	.10	.76	.05	.0003
Wet Bottom Boilers	10.39	1.16	.03	1.53	.02	.0003
Dry Bottom Boilers	13.59	1.16	.03	.92	.02	.0003
Cyclone Boilers	1.60	1.16	.03	2.80	.02	.0003

Water quality considerations for fossil-fueled boilers are concerned mainly with: (1) thermal emissions when waste heat is not used, (2) water requirements for boiler feed, and (3) water quality requirements for boiler feed to prevent corrosion. A 60 MW fossil plant will use about 4.2-4.5 pounds of water per kWh for boiler feed or 250×10^3 lbs/hr. Water quality must have the following specifications:

Total dissolved solids and nondissolved solids	<.25 ppm
Sodium and Potassium	<.25 ppm
No Silica	
pH	6.5-7.0

Typical systems require a series of filters followed by a reverse osmosis unit and a deionization or demineralization unit. Water quality emissions from these units are essentially identical to the influent with the exception of total dissolved solids which is 3 to 4 times that of the influent.

Other sources of wastewater which must be monitored include ash transport water, metal cleaning wastes, cooling water and blowdown water. Oil and grease are the primary contaminants in low volume water discharge from steam generating plants. Total suspended solids and acidity can also become a problem in ash transport and blowdown water. Make-up water requirements for fossil boilers is perhaps the most significant water quality issue for larger units. Appendix I presents typical waste use and coal pile runoff pollutant concentrations.

1.3.2 Emissions from Internal Combustion Engines

Internal combustion engines provide simple operation and high reliability for engine sizes from a few horsepower to over 40,000 horsepower although large U.S. produced IC engines range up to 13,000 Bhp. IC engines may be full diesel, spark ignition, gas, or dual fuel. They may be used to drive generators, chillers, or any mechanism requiring rotary energy. Reliability of an IC engine is perhaps its best feature and is closely related to the exhaust temperature which ranges from 800° to $1,300^{\circ}$ F, depending on engine size and efficiency. Fuels include natural gas, LPG, gasoline, or diesel fuel for stationary power generation. Diesel appears to be the most popular, with spark ignition and dual fuel significantly less popular.²²

Fuel use in an IC engine depends on the relative efficiency of the engine as it operates under design conditions. Typical diesel-engine thermal efficiencies are about 30 to 40% in a size range from about 500 to 8,000 Bhp. This corresponds to heat rates from 7,500 to 6,700 Btu/hp/hr. Given a diesel engine with a thermal efficiency of about 37%, about 33% of the energy in the fuel is rejected as exhaust waste heat. Another 16% of the input fuel energy is transferred to the water jacket, and another 7% is emitted as thermal radiation. A total of 56% of the energy input the diesel is transformed to nonproductive heat.

Of the two types of firing mechanisms, spark-ignition engines have generally the same operational characteristics as their diesel counterparts. With exhaust gases from 800° to 1,350°F, heat recovery from the water jacket and exhaust are quite feasible. IC engine operation, with design conditions usually at full load, promote good combustion. Hydrocarbon, CO, and soot emissions easily meet regulatory constraints under normal operating conditions. However, high operating temperatures cause high NO₂ emissions which can cause concern when engines are clustered in a restricted space. Lowering of combustion temperatures or pressure to recover waste heat will reduce NO₂ emissions. When heat recovery is utilized, CO emissions are critical and are likely to be the first to violate emission standards. Table 1.26²³ presents typical exhaust emissions from a diesel engine using No. 2 distillate fuel oil. Under these conditions the sulfur content is .1%. Fuels having higher sulfur contents will have proportionately higher SO₂ emission rates.

1.3.3 *Combustion Turbines*

One common example of combustion turbine operation is the aircraft engine. In the case of a jet engine, air is taken into the front of the engine where it is compressed, sometimes preheated, and then introduced into a combustion chamber. Addition of fuel and ignition of the mixture causes a rapid expansion of combustion gases across the combustion zone. In a jet engine, continued expansion creates thrust to drive the aircraft. In stationary gas turbines, the high-temperature exhaust drives turbines fixed to a rotating shaft. The rotary energy then is used to drive refrigeration equipment or electrical generators or any other rotary load. Figure 1.2 illustrates a simple stationary gas turbine; Fig. 1.3 illustrates use of a regenerator and a com-

Figure 1.2. Schematic of a Simple Gas Turbine Cycle

GAS TURBINE

Figure 1.3. Schematic of a Combined Cycle Gas Turbine with a Regenerator

TABLE 1.26. IC Engine Emissions²³

% Load	kW	Assumed Generator Efficiency %	Bhp	Emission Rate (g/hr)				
				HC	CO	NO ₂ ^a	SO ₂ ^b	Soot
100	475.00	94.4	675	40	560	4,608	250	30
75	356.25	94.6	505	35	450	3,353	187	25
50	237.25	93.8	340	105	380	2,391	127	28
25	118.75	91.3	173	320	440	1,443	75	45
0	0	-	0	570	960	120	31	75

^aCorrected to 75 grains humidity.

^bSO₂ is in g/hr per 0.1% sulfur in the fuel.

(Note: These data are from a 180°F jacket water aftercooled engine. The NO₂ values from a 130°F water cooled aftercooler engine should be somewhat lower.)

bined cycle. Combined-cycle units utilize waste heat from the gas turbine to generate and drive a steam turbine and thereby greatly increasing engine efficiency.

Mass emissions from simple-cycle gas turbines and combined-cycle units are identical. Only if the combined-cycle unit uses an auxiliary fossil-fired boiler will emissions increase, and these will be from the fossil-fired auxiliary unit (see Table 1.26).

Generally, turbines operating at base load have visible emissions of less than 10% opacity. Such a visible emission will not create significant regulatory compliance problems. Sulfur dioxide emissions from combustion turbines are directly proportional to the sulfur content of the fuel for any given efficiency. Virtually all the sulfur in the fuel is converted to oxide and emitted as exhaust meeting SO₂ standards. If high sulfur fuel is burned, however, emissions can be significant. A 33-MW gas turbine burning 0.1% sulfur fuel emits about 33 lbs of SO₂ per hour, well within regulatory statutes. Using a 1.9% sulfur fuel, however, emissions increase to 690 lbs per hour. General commercial gas turbines have operated well with fuel having sulfur contents in the range of .01 to .5%.

Particulate emissions from gas turbines consist of ash from the fuel and carbon and hydrocarbon solids from incomplete combustion. Particulate emissions range from 1 lb/hr to over 40 lb/hr with concentrations from .002 gr/scf to .10 gr/scf. To a large degree fuel influences particulate emission rates. A 20 MW turbine, for example, burning natural gas emits 4.8 lb/hr of particulates, whereas, the same turbine burning #2 fuel oil could emit particulates in the range of 20 lb/hr. Because of fine particulate emissions from gas turbines, visible emissions tend to be more of a problem than with sources having emissions with greater particle size. With proper turbine operation opacities can be maintained below 10%, and particulate emissions can be maintained within regulatory constraints. Incomplete combustion is the principle cause of hydrocarbon (HC) emissions and carbon monoxide (CO) emissions. Because turbines are typically designed for full load, operation at less than full load creates larger CO and HC emissions. Start-up and low-load operation result in maximum emission rates. Likewise, when firing temperatures decrease, poor burning conditions terminate combustion before completion, and high CO and HC emissions levels exist. High inlet air temperatures with firing temperatures above 700°C provide excellent combustion conditions and low CO, HC emission control is careful control of fuel-air ratios. It should be noted however that excess air can cause a rapid increase of HC emissions.²⁴

Nitrogen oxides are produced by the combination of nitrogen and oxygen in combustion air (thermal NO_x) and the combination of nitrogen in the fuel and oxygen in the air (organic NO_x). Thermal NO_x formation occurs in the combustion zone. The chemical mechanism is similar to that discussed in fossil-fueled boilers. Moisture or humidity in inlet air will result in lower combustion temperatures and lower NO_x emissions; conversely, high inlet temperatures and pressures will favor high NO_x concentrations during combustion equilibrium. Organic NO_x formulation also occurs in the combustion zone. Nitrogen from the fuel combines with combustion air forming NO_x. As a result, certain fuels having low nitrogen content will yield lower overall NO_x emission rates. Residual oils for example have nitrogen contents as high as 2%. Crude oils have nitrogen contents around .2%, and most light distillates less than .015%. Although fuel quality is a contributory factor to NO_x formation, temperature remains the primary precursor to NO_x emissions. Table 1.27 presents air pollutant emissions associated with combustion, turbine size, and fuel use.

TABLE 1.27. Turbine Emissions

Size (MW)	Heat Rate	Fuel	Fuel Quality	SO ₂		NO _x			CO		
			%S	#/hr.	#/10 ⁶ Btu	PPM @ 15%	#/hr.	lb/10 ⁶ Btu	PPM @ 15%	#/hr.	lb/10 ⁶ Btu
.15	23,854	Jeta	.01	.039	.076	55	.94	1.83	321	3.3	6.43
			.1	.39	.759						
.50	15,742	NG	0	0		109	3.69	2.0	7	.15	.08
			.01	.09	.05	149	4.76	2.64	21	.41	.23
			.1	.88	.21						
.80	15,690	NG	0	0		51	2.64	.62	68	2.13	.50
			.01	.17	.04	68	4.03	.94	163	5.76	1.35
		Kerosene	.1	1.71	.40						
2.5	12,930	NG	0	0		99	16.69	1.96	11	1.17	.138
		DF-1	.1	3.51	.413	125	20.67	2.42	57	5.77	.68
			.3	10.54	1.24						
			.5	17.57	2.06						
12.5	15,680	DF-2	.1	21.30	.50	120	102	2.39	29	15.3	.36
			.3	63.91	1.50						
			.5	107	2.50						
23.5	11,964	DF-2	.1	30.6	.38	147	187	2.32	7.8	6.0	.07
			.3	91.7	1.14						
			.5	153	1.90						
29.2	13,420	DF-2	.1	42.6	.43	189	390	3.90	31	39.4	.39
			.3	128	1.28						
			.5	213	2.14						
51	11,859	DF-2	.1	66.6	.38	315	310	1.77	30	47.2	.27
			.3	200	1.13						
			.5	332	1.90						
60.3	10,846	NG	0	0		119	263	1.29	2.3	3.1	.015
78.9	11,320	DF-2	.1	97.0	.36	227	925	3.43	17.5	43.9	.16
			.3	291	1.08						
			.5	485	1.80						
88.7	11,320	DF-2	.1	108	.38	337	1578	5.55	17.97	199	.70
			.3	324	1.08						
			.5	540	1.80						

Noise emissions from combustion turbines can be considerable. Demineralizers and associated equipment have associated noise levels of 85-100 dba. Turbine emissions, however, can far exceed those levels. Noise abatement is mandatory, and even with attenuation and silencers levels could be from 90-100 dba within a 250-ft radius.

Water quality considerations for turbine operation are primarily associated with the amount and quality of water injected into the turbine. To prevent excessive corrosion of gas turbine components, high-purity water must be used. As in the case of boiler feedwater, pH must be maintained with silica concentrations less than .02 ppm, sodium and potassium concentrations less than .5 ppm, and total dissolved and nondissolved solids between 1 and 5 ppm. These water quality requirements are slightly less stringent than fossil-fired boiler feed requirements. Quantities of water utilization are about half fossil-fueled boiler feed requirements (2.0-2.1 lb/kW-hr) for a 60-MW plant or about 120×10^3 lb/hr of water use. As in the case of fossil boilers, a reverse osmosis unit and demineralization or deionization unit is required. For fossil demineralizers and reverse osmosis equipment, total dissolved solids may be three to four times the concentration of the influent.

1.3.4 Emissions from Incinerators

Disposal of combustible wastes in an ICES presents a unique opportunity to relieve, or at least reduce the community's refuse disposal problem and at the same time increase the total efficiency of the ICES. Incinerators can be used to generate steam for power production, process use, chiller operation, or domestic water and space heating. In most cases, incinerators will be fitted with water or fire tubes making them a hybrid steam generating plant. Because incinerators will be used as water heaters or steam generators, they will most likely be regulated under general combustion regulations and incinerator regulations. Because most ICES incinerators will be small compared to steam-generating units, their operation will most often be controlled by incinerator regulations which regulate incinerators with charging rates as low as 10 lb/hr.

Particulate emission is the pollutant of prime concern regarding incinerator operation. Incinerators with higher firing rates require control equipment to meet local regulation. Environmental emissions are dictated by the following parameters:

pollutant content by the solid waste,
 air flow design,
 burning rate,
 firing temperature, and
 grate and combustion chamber design.

Sulfur oxide emissions are not affected by incinerator design because all sulfur in the waste material is converted to sulfur oxide. Carbon monoxide, hydrocarbons, and nitrogen oxides are influenced by incinerator design in that designs such as multiple chamber incinerators which promote complete combustion tend to have lower emission rates. Although the exact heat content of the municipal or ICES waste will dictate emission characteristics, Table 1.28 illustrates typical emission levels.²⁵

Sludge incineration is another approach to waste disposal/energy production with ICES application. Sludge incinerators differ from refuse incinerators in that sludge does not normally supply enough heat to sustain combustion. Less ash is retained, and other pollutant levels can be considerably higher. Table 1.29 presents typical emission levels from sludge incineration.

1.3.5 Electrical Generators, Transformers and Substations

Airborne emissions from transformers and substations do not present environmental constraints on ICES developers at the present time. Ozone generation from electrical discharge has not become an issue of concern and is not likely to pose any problems for small low voltage systems. Noise emissions and emission of polychlorinated biphenyl compounds are issues for which ICES developers should be made aware. EPA allows no escape of polychlorinated biphenyls restricting the repair and disposal of old units.

Noise from transformers range from 60 to 80 dba violating certain residential noise regulations. A 300 KVA self-cooled transformer will have an associated sound level of 66 dba. A forced-air cooled transformer the same size will have a noise level of 70 dba. At 700 KVA, noise levels go to 72 and 75 dba for self- and forced-air cooled transformers. At 1,000 KVA, noise levels go to 74 and 77 dba with 1,500 KVA transformers having associated noise levels of 76 and 79 dba.

TABLE 1.28. Incinerator Emissions

Incinerator Type	Charging Rate (T/hr)	Emissions (lbs/hr)				
		Particulates	Sulfur Oxides	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides
<u>Municipal (> 50 T/day)</u>						
Multiple Chamber, uncontrolled	4.0	120.0	6.0	140.0	6.0	8.0
With settling chamber and water spray system	4.0	56.0	6.0	140.0	6.0	8.0
<u>Industrial/Commercial (50-4000 lb/hr)</u>						
Multiple chamber	2.0	14.0	3.0	20.0	6.0	6.0
	1.0	7.0	1.5	10.0	3.0	3.0
	.25	1.75	.375	2.5	.75	.75
	.05	.35	.075	.5	.15	.15
Single chamber	2.0	30.0	3.0	40.0	30.0	4.0
	1.0	15.0	1.5	20.0	15.0	2.0
	.25	3.75	.375	5.0	3.75	.5
	.05	.75	.075	1.0	.75	.1
Controlled air	2.0	2.8	3.0	neg	neg	20.0
	1.0	1.4	1.5			10.0
	.25	.35	.375			2.5
	.05	.07	.075			.5

TABLE 1.29. Sludge Incinerator Facility Typical Emissions⁴⁰

Item	Average Emissions Levels
Furnace feed rate, ton/h dry solids	0.557
Stack effluent:	
Flow rate, dscfm	2,700
Flow rate, dscf/ton feed	291,000
Temperature, °F	59
Water vapor, volume %	2.03
CO ₂ , volume % dry	12.3
O ₂ , volume % dry	5.3
CO, volume % dry	0
SO ₂ emissions, ppm	<0.3
NO _x emissions, ppm	5.4
HCl emissions, ppm	<3.6
Visible emissions, % opacity	10
Particulate emissions	
Probe and filter catch:	
gr/dscf	0.011
gr/acf	0.011
lb/h	0.266
lb/ton of feed	0.481
Total catch:	
gr/dscf	0.0163
gr/acf	0.016
lb/h	0.389
lb/ton of feed	0.704

1.3.6 Emissions from Chillers

Chillers, as in the case of electrical generators, have the capacity for emission of mechanical vibration and noise.

Properly designed chillers present little problem regarding air or water emissions. Of key importance in chiller utilization is its source of rotational energy. Chillers may operate using steam turbines operating on steam from fossil plants or incinerators. Larger chillers may use combustion turbines or IC engines to provide rotational energy. ICES design will dictate the most efficient prime mover and its relationship to chiller operation. Environmental emissions from the chiller driven can be assessed by reviewing fossil-fueled boiler emissions, IC engine, or turbine emissions. Noise emissions from the chilled water pump motor can reach 96 dba in the 1,000 Hz fre-

quency range. Because chillers will most likely be situated in the utility plant, sound isolation will not be a major cost issue. If, however, chillers are located away from other noise isolated equipment, noise abatement must be employed.

1.4. ENVIRONMENTAL REGULATIONS

Planners and developers of Community Energy Systems face a complex of regulations relating to the attainment and preservation of air quality in the vicinity of the energy system. Environmental restrictions, as most regulatory legislation, exist on three levels, namely, federal legislation, state legislation, and local law. In the case of environmental legislation, jurisdictional authority overlaps, this requiring certain sources to show compliance with local, state, and federal regulations before construction may begin. Administratively and institutionally, each level of government is independent of the other. Thus, satisfaction of federal laws, only, does not constitute project approval. State planners and permits must be satisfied, and final satisfaction of local law is necessary before environmental regulatory procedures are satisfied. Regulations on each level of government may be similar or completely different, depending on state and local law.

To assess the Community Energy System properly, interface with environmental legislation and regulation from each sector of government must be reviewed. Regulations impacting energy system components must be identified and compared with probable emission levels to identify potential "environmental troublespots."

1.4.1 Federal Air Pollution Control Legislation/Regulation

Federal environmental regulation centers around the Clean Air act of 1970, and will be greatly influenced by the 1977 revisions. The 1970 Act suggested that increased urbanization and industrial development resulted in complex air pollution problems affecting the public health and welfare. Prevention and control of air pollution at its source became the prime responsibility of state and local governments and federal leadership and assistance became an integral part of the 1970 Act.

Thus, the prime objectives of the Clean Air Act are:

- 1) To protect and enhance the quality of the nation's air resources so as to promote public health and welfare;

- 2) To assist state and local governments in developing air pollution prevention and control programs.

The 1970 Act accomplishes its objectives by establishing a schedule by which EPA and the States are to meet and maintain specified air quality standards. Table 1.30 presents specified air quality standards. In the case of primary standards, these air quality levels were to have been achieved by May 31, 1975.

To reach the specified standards, state, local, and federal enforcement programs were established to enforce and maintain regulatory compliance. States have been required to develop and submit to the federal government for approval sets of State Implementation Plans (SIPs). Each SIP addresses the state's air quality problem and presents those regulations intended to attain and maintain air quality at federally mandated levels. SIP's cover five "criteria" pollutants: total suspended particulates (TSP), sulfur dioxide (SO₂), carbon monoxide (CO), oxidants/ozone (Ox, Oz) and nitrogen dioxide (NO₂). When states do not enforce air pollution control regulations, the Act requires EPA to take action. In accordance with the intention of the Act, EPA has designed an assistance and enforcement program to ensure that all U.S. sources achieve compliance with applicable regulations. Federal regulation has been established as part of EPA's enforcement program which places specific emission and air quality constraints on specific sources.

- *New Source Performance Standards.* Under Section III of the Clean Air Act, certain industrial facilities are subject to new source performance standards established by EPA and enforced federally (unless states accept delegation enforcement authority). Table 1.31 lists sources subject to national emission regulations. CES components affected by NSPS include fossil-fuel-fired steam generators, municipal incinerators, and sewage treatment plants. Table 1.31 presents applicable NSPS emission standards for CES components. To illustrate the level of federal enforcement actions, during the first six months of 1976, there were 4,079 federal investigations under Section 114 of the Act. This compares with over 87,000 investigations, conducted by state agencies.

- *New Source Review.* Authority given by the Clean Air Act has permitted EPA to establish requirements for preconstruction review of specified new or modified stationary sources. The provisions for preconstruction review include:

TABLE 1.30. Summary of National Ambient Air Quality Standards²⁷

Pollutant	Averaging Time	Primary Standards	Secondary Standards
Particulate Matter	Annual (Geometric Mean)	75 $\mu\text{g}/\text{m}^3$	60 $\mu\text{g}/\text{m}^3$
	24 - Hour	260 $\mu\text{g}/\text{m}^3$	150 $\mu\text{g}/\text{m}^3$ †
Sulfur	Annual (Arithmetic Mean)	80 $\mu\text{g}/\text{m}^3$ (0.03 ppm)	_____
Oxides	24 - Hour	365 $\mu\text{g}/\text{m}^3$ (0.14 ppm)	_____
	3 - Hour	_____	1,300 $\mu\text{g}/\text{m}^3$ (0.5 ppm)
CO	8 - Hour	10 mg/m^3 (9 ppm)	(Same as Primary)
	1 - Hour	40 mg/m^3 (35 ppm)	(Same as Primary)
NO ₂	Annual (Arithmetic Mean)	100 $\mu\text{g}/\text{m}^3$ (0.05 ppm)	(Same as Primary)
Photochemical Oxidants	1 - Hour	160 $\mu\text{g}/\text{m}^3$ (0.08 ppm)	(Same as Primary)
Hydrocarbons (Nonmethane)	3 - Hour* (6 to 9 a.m.)	160 $\mu\text{g}/\text{m}^3$ (0.24 ppm)	(Same as Primary)

* Guideline

TABLE 1.31. New Source Performance Standards

STEAM GENERATORS				
(>250 million Btu/hr) Promulgated 12/23/71 (36 FR 24876) Revised 6/14/74 (39 FR 20790) 1/16/75 (40 FR 2803) 10/6/75 (40 FR 2803)	Coal fired boilers	Particulate	0.10 lb/10 ⁶ Btu	No requirement
		Opacity	20%	Continuous
		SO ₂	1.2 lb/10 ⁶ Btu	Continuous
		NO _x	0.70 lb/10 ⁶ Btu	Continuous
		(except lignite and coal refuse)		
	Oil fired boilers	Particulate	0.10 lb/10 ⁶ Btu	No requirement
		Opacity	20%; 40% 2 min/hr	Continuous
		SO ₂	0.80 lb/10 ⁶ Btu	Continuous
		NO _x	0.30 lb/10 ⁶ Btu	Continuous
	Gas fired boilers	Particulate	0.10 lb/10 ⁶ Btu	No requirement
SUBPART E:				
INCINERATORS (>50 tons/day) Promulgated 12/23/71 (36 FR 24876) Revised 6/14/74 (39 FR 20790)	Incinerators	Particulate	0.80 gr/dscf corrected to 12% CO	No requirement
SEWAGE TREATMENT PLANTS				
Promulgated 3/8/74 (39 FR 9308) Revised 4/17/74 (39 FR 13776) 5/3/74 (39 FR 15396) 10/6/75 (40 FR 46250)	Sludge incinerators	Particulate	1.30 lb/ton	Mass or volume of sludge
		Opacity	20%	No requirement
SUBPART Y:				
COAL PREPARATION PLANTS Promulgated 1/15/76 (41 FR 2232)	Thermal dryer	Particulate	0.031 gr/dscf (0.070 g/dscm)	Temperature
		Opacity	20%	Scrubber pressure loss
	Pneumatic coal cleaning equipment	Particulate	0.018 gr/dscf (0.040 g/dscm)	No requirement
		Opacity	10%	No requirement
SUBPART Y:				
COAL PREPARATION PLANTS Promulgated 1/15/76 (41 FR 2232)	Thermal dryer	Particulate	0.031 gr/dscf (0.070 g/dscm)	Temperature
		Opacity	20%	Scrubber pressure loss
	Pneumatic coal cleaning equipment	Particulate	0.018 gr/dscf (0.040 g/dscm)	Water pressure
		Opacity	20%	No requirement
	Processing and conveying equipment, storage systems, transfer and loading systems	Particulate	0.018 gr/dscf (0.040 g/dscm)	No requirement
		Opacity	10%	No requirement
		Opacity	20%	No requirement
				No requirement

- (1) sources that may interfere with the attainment or maintenance of National Air Quality Standards (SSR).
- (2) sources that may cause significant deterioration of air quality (PSD).
- (3) sources that emit hazardous air pollutants in excess of prescribed limitations (NESHAP).
- (4) sources subject to new source performance standards (NSPS).

Table 1.32 presents the status of new source review responsibilities.²⁹ As indicated, 50 or 55 state jurisdictions have established state new source review laws. In these cases, developers must show compliance with state agencies. NSPS has been accepted by half the jurisdictions with only a few states having approved PSD plans. In cases where states have not delegated authority, developers deal with federal agencies, usually at the regional office level.

CES development is directly impacted by three federal Clean Air Act related enforcement programs, NSPS, PSD and SSR. Although new source review is emission-oriented and violations easily discernable, PSD and SSR are air-quality oriented and depend on site-specific local meteorological, air quality, and geographic conditions. It is not easily established if a CES is in violation of air quality standards until the source is placed in a specified setting.

Aside from the Clean Air Act, the National Environmental Policy Act of 1969 (NEPA) could under certain cases place specific environmental control requirements on CES developers. NEPA requires federal agencies to prepare environmental impact statements on major federal actions significantly affecting the quality of the environment. The Act requires federal and public review and approval. NEPA has direct impact on CES development whenever:

- 1) federal funds are used (HUD Development), or
- 2) federal grants involve federal land.

About 3% of all environmental impact statements involve HUD development, and CES developments are likely to involve HUD, and will require an Environmental Impact Statement. In addition to federal EIS requirements, about a dozen states have adopted EIS statutes requiring state reports, independent of any federal reports.

An Environmental Impact Statement is a comprehensive plan of the proposed development. In the EIS, environmental emissions must be identified and quantified. It must be demonstrated that applicable environmental laws will be enforced, and that environmental degradation will not occur. Federal EIS's are

TABLE 1.32. Program Status of Federal Regulations²⁹

	NSPS	PSD	SSR
<u>REGION I</u>			
Connecticut	D	-	A
Maine	D	I	A
Massachusetts	D	-	A
New Hampshire	D	-	A
Rhode Island	N	-	A
Vermont	D	I	A
<u>REGION II</u>			
New Jersey	N	I	A
New York	D	I	A
Puerto Rico	N	-	A
Virgin Islands	D	-	A
<u>REGION III</u>			
District of Columbia	-	-	A
Delaware	N	I	A
Maryland	-	I	A

D - Delegated EPA Authority
 N - Negotiating for Authority
 I - Interested in Requesting Authority
 A - Adopted state Regulations

TABLE 1.32. Program Status of Federal Regulations (Contd.)

	NSPS	PSD	SSR
<u>REGION III</u>			
Pennsylvania	N	I	A
Virginia	D	I	A
West Virginia	I	-	A
<u>REGION IV</u>			
Alabama	D	D	A
Florida	-	-	A
Georgia	D	D	A
Kentucky	D	D	A
Mississippi	N	N	A
North Carolina	D	D	A
South Carolina	D	D	A
State of Tennessee	N	D	A
Nashville	D	D	A
Knoxville	D	N	A
Chattanooga	N	-	A
Memphis	N	-	A

D - Delegated EPA authority
 N - Negotiating for Authority
 I - Interested in Requesting authority
 A - Adopted state regulations

TABLE 1.32. Program Status of Federal Regulations (Contd.)

	NSPS	PSD	SSR
<u>REGION V</u>			
Illinois	N	-	A
Indiana	D	I	N
Michigan	D	I	A
Minnesota	N	-	A
Ohio	D	-	A
Wisconsin	D	I	A
<u>REGION VI</u>			
Arkansas	-	I	A
Louisiana	N	-	A
New Mexico	-	-	A
Oklahoma	N	I	A
Texas	N	-	A
<u>REGION VII</u>			
Iowa	D	-	A
Kansas	I	-	A
Nebraska	D	N	A
Missouri	N	-	A

D - Delegated EPA authority
 N - Negotiating for Authority
 I - Interested in Requesting Authority
 A - Adopted state regulations

TABLE 1.32. Program Status of Federal Regulations (Contd.)

	NSPS	PSD	SSR
<u>REGION VIII</u>			
Colorado	D	I	A
Montana	N	I	A
North Dakota	D	A	A
South Dakota	D	I	A
Utah	D	I	-
Wyoming	N	I	A
<u>REGION IX</u>			
California			
Bay Area	D	-	
Del Norte	D	-	
Fresno	D	-	
Humboldt	D	-	
Kern	D	-	
Madera	D	-	
Mendocino	D	-	
Monterey	D	-	
N. Sonoma	D	-	
Sacramento	D	-	
San Joaquin	D	-	
D - Delegated EPA Authority N - Negotiating for Authority I - Interested in Requesting Authority A - Adopted State Regulations			

TABLE 1.32. Program Status of Federal Regulations (Contd.)

	NSPS	PSD	SSR
<u>REGION IX</u>			
California			
Stan	D	-	
Santa Barbara	D	-	
Trin	D	-	
Ventura	D		
San Diego	D		
Yolo Solana	D		
Arizona			
Pima	D		
Maricopa	N		
Nevada			
DHS	D		
Clark	D		
Washoe	D		
Hawaii	I	-	
Guam	-	-	
American Samoa	-	-	A
<u>REGION X</u>			
Alaska	N	-	A
Idaho	D	-	A
Oregon	D	I	A
Washington	D	N	A

D - Delegated EPA Authority
 N - Negotiating for Authority
 I - Interested in Requesting Authority
 A - Adopted State Regulations

reviewed by Regional Offices (EPA, DOT, HUD, etc.) and in the case of EPA, judged to be LO, ER, or EU. Environmentally sound projects (LO rated) may proceed with construction, ER projects have specific deficiencies, and EU projects may not be built. The developer's concern with NEPA is the assurance that environmental emissions meet applicable standards. Although HUD writes the statement, the developer may require environmental technical assistance in developing HUD-required data and in obtaining necessary permits. Environmental Impact Statements also apply to noise and water emissions.

1.4.2 State and Local Air Pollution Control Regulations

After determining federal regulations which apply to an ICES, the developer must consult state and local law. HUD and municipal systems required to file Environmental Impact Statements must demonstrate conformance with local controls. Independent of impact statements, builders must obtain a state permit and in some cases, a local permit to construct an air pollutant source. After construction is completed, permits to operate the facility may also be required. An integral part of these permits is the estimation of emissions, degree of control, if required, and the establishment of an inspection schedule.

Interaction between federal, state and local air pollution control agencies is similar to the interaction between federal, state and local law enforcement agencies. While limited ties exist between federal and local agencies, investigations are often handled independently. Large sources may be inspected by federal, state and/or local enforcement personnel together or independently. Enforcement of federal, state and local laws may also be handled independently.

ICES developers must first satisfy local zoning laws to develop a site. Zoning and ICES siting will be discussed in detail in Chapter 2. Next the ICES developer must demonstrate compliance with local air pollution control laws to obtain a building permit. In larger municipalities the air pollution control agency may issue a separate permit required to construct an air pollution source. It should now be noted that compliance with local laws is not enough. Most states maintain a statewide permit system which requires compliance with state laws. After obtaining a state permit, the ICES developer need only determine if his facility uses federal funds making an environmental impact statement necessary.

When a question exists regarding air pollution regulations applicable to a development, the state implementation plan can be a useful reference. The State Implementation Plan (SIP) is a plan or set of regulations which is submitted to the federal government for approval. The SIP demonstrates how air quality standards are to be achieved locally and statewide. This plan will contain applicable state and local control regulations.

In this section, state and local air pollution control regulations have been reviewed and summarized. Only those regulations likely to impact ICES development are presented.

- *Particulate Limitations for Combustion Sources.* Combustion regulations apply generally to all the fossil-fueled ICES components including coal, oil, and gas-fired boilers. Table 1.33 presents state and local particulate regulations. As presented, solid and liquid fuels often have different performance standards. New installations are generally restricted under separate regulations. While emission rates and specified per unit of heat input, most states have sliding scales limiting emission rates on larger boilers. Table 1.34 summarizes the stringency of particulate regulations by boiler size for new sources.

- *Particulate Emission Limitations for Incinerators.* Incinerators have been placed in a separate category, aside from general combustion sources. Incinerators used as auxillary heat sources to produce steam or hot water most likely will be subject to state and local incinerator regulations. Table 1.35 presents particulate regulations for new multiple chamber incinerators. Emission levels are usually dependent upon charging rates and are directly proportional.

Incinerators are categorized by the type of waste burned and the rate of incineration. State regulations limit particulate emissions from incinerators by charging rates. Sometimes waste type is also used as a criterion for determining allowable emissions waste classifications used in 1.38 appear below.³⁰

Classification of Wastes:

Type 0 - Trash; 10% moisture, 5% incombustible solids;
heating value of 8,500 Btus per lb as fired.

Type 1 - Rubbish; 25% moisture, 10% incombustible solids;
heating value of 6,500 Btus per lb as fired.

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources

Allowable Emissions - 1b PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Alabama</u>			0.10	0.10	NSPS
Class I Counties	0.50	0.50	0.50	0.50	H.I. per stack $\leq 10 \times 10^6$ Btu and all new sources
Class I Counties	1.38 (H.I.) ^{-0.44}	1.38 (H.I.) ^{-0.44}	1.38 (H.I.) ^{-0.44}	1.38 (H.I.) ^{-0.44}	10 < H.I. < 250x10 ⁶ Btu and all new sources
Class I, II Counties	0.12	0.12			H.I. per stack $\geq 250 \times 10^6$ Btu
Class II Counties	0.80	0.80			H.I. per stack $\leq 10 \times 10^6$ Btu
Class II Counties	3.109 (H.I.) ^{-0.589}	3.109 (H.I.) ^{-0.589}			10 < H.I. < 250x10 ⁶ Btu
<u>Alaska</u>					
	0.24	0.24			Sources prior to 7/1/72: .10gr/SCF
	0.24				Sources after 7/1/72:
		0.11			Coal or Waste Firing: .10 gr/SCF
			0.10	0.10	Other Fuel Firing: .05 gr/SCF
					Fossil Fuels
<u>Arizona</u>					
	1.02 (H.I.) ^{-0.231}	1.02 (H.I.) ^{-0.231}	1.02 (H.I.) ^{-0.231}	1.02 (H.I.) ^{-0.231}	10 < H.I. per stack < 4000x10 ⁶ Btu
	0.21	0.21			H.I. = 1000
<u>Arkansas</u>					
					Regs expressed as conc. limits.
					State reg. for new or modified source: Emission rate w/o control < 1000 lb/hr: 0.4167 (rate) 0.7782 lb/hr
					Emission rate w/o control $\geq$ 1000 lb/hr: 4.3574 (rate) 0.4383 lb/hr
<u>California</u>	0.24	0.21			
AQCRs 23,27,29,30,32					0.3 gr/SCF ^a
AQCR 24					
SW LA, Orange, So. Santa Barbara Counties.					Existing Sources - 0.3 gr/SCF ^a
W. Riverside, SW San Bernadino, Ventura Counties					Existing Sources - 0.1 gr/SCF ^a
So. Santa Barbara County					New Sources - 0.3 gr/SCF ^a
Other Counties					New Sources - 10 lb/hr

^a Corrected to 50% excess air.

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>California (Contd.)</u>					
AQCR 25					
Monterey, Santa Cruz Counties					0.15 gr/SCF ^a
San Benito County					0.3 gr/SCF ^a
AQCR 26					
No. Sonoma County					0.1 gr/SCF ^a
Lake County					New Sources - 0.1 gr/SCF ^a
Other Counties					0.2 gr/SCF ^a
AQCR 28					
Plumas County					0.01944 gr/SCF ^a
Shasta County					Stack height < 1000 ft: 0.15 gr/SCF ^a
					Stack height > 1000 ft: 0.3 gr/SCF ^a
Other Counties					0.3 gr/SCF ^a
AQCR 31					
Madera County					Existing Sources - 0.3 gr/SCF ^a
Other Counties					Existing Sources - 0.1 gr/SCF ^a
W. Kern County					New Sources - 0.1 gr/SCF ^a
Madera County					New Sources - 0.1 gr/SCF ^a and 10 lb/hr
Other Counties					New Sources - 10 lb/hr
AQCR 33					
E. Kern County					Existing Sources - 0.2 gr/SCF ^a
San Bernadino County					Existing Sources - 0.1 gr/SCF ^a
Other Counties					Existing Sources - 0.3 gr/SCF ^a
E. Kern, San Diego Counties					New Sources - 0.1 gr/SCF ^a
Other Counties					New Sources - 10 lb/hr

^aCorrected to 50% excess air.

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions - 1b PM/10 ⁶ Btu				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Colorado</u>	0.5 0.5 (H.I.) ^{-0.26} 0.1	0.5 0.5 (H.I.) ^{-0.26} 0.1			H.I. per boiler ≤ 1x10 ⁶ Btu 1 < H.I. < 500x10 ⁶ Btu H.I. per boiler ≥ 500 x 10 ⁶ Btu NSPS
<u>Connecticut</u>	0.20	0.20	0.10	0.10	
<u>Delaware</u>	0.3	0.3	0.3	0.3	H.I. per boiler ≥ 1x10 ⁶ Btu
<u>D.C.</u>	0.13 0.175 (H.I.) ^{-0.235} 0.03	0.13 0.175 (H.I.) ^{-0.235} 0.03	0.13 0.175 (H.I.) ^{-0.235}	0.13 0.175 (H.I.) ^{-0.235}	H.I. per stack ≤ 3.5x10 ⁶ Btu 3.5 < H.I. < 10,000x10 ⁶ Btu H.I. = 1000
<u>Florida</u>	0.1	0.1	0.1	0.1	H.I. per plant > 250x10 ⁶ Btu H.I. ≤ 250x10 ⁶ Btu "Latest Technology"
<u>Georgia</u>	0.70 1.115 (H.I.) ^{-0.202} 0.28	0.70 1.115 (H.I.) ^{-0.202} 0.28	0.50 1.581 (H.I.) ^{-0.5} 0.10	0.50 1.581 (H.I.) ^{-0.5} 0.10	H.I. per boiler < 10x10 ⁶ Btu 10 ≤ H.I. ≤ 2000x10 ⁶ Btu H.I. = 1000 H.I. per boiler < 10x10 ⁶ Btu 10 ≤ H.I. ≤ 250x10 ⁶ Btu H.I. per boiler > 250x10 ⁶ Btu
<u>Hawaii</u>	1.0	1.0			Bagasse Burners: 0.4 lb/100 lb bagasse
<u>Idaho</u>	0.60 1.206 (H.I.) ^{-0.233} 0.24	0.60 1.206 (H.I.) ^{-0.233} 0.24	0.10	0.10	H.I. per stack < 10x10 ⁶ Btu 10 ≤ H.I. ≤ 10,000x10 ⁶ Btu H.I. = 1000 NSPS

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Illinois</u>					
Chicago MMA	0.1				
Other Areas	1.0				
	5.18 (H.I.) ^{-0.715}	5.18 (H.I.) ^{-0.715}			H.I. per stack $\leq 10 \times 10^6$ Btu
	0.1				10 < H.I. < 250x10 ⁶ Btu
	0.2				H.I. per stack $\geq 250 \times 10^6$ Btu
					Controlled Sources
		0.1	0.1	0.1	
<u>Indiana</u>					
AQCRs 67,80	0.87 (H.I.) ^{-0.16}	0.87 (H.I.) ^{-0.16}			
Other Areas	0.8	0.8			
			0.6	0.6	H.I. per plant < 250x10 ⁶ Btu
			0.1	0.1	H.I. per plant $\geq 250 \times 10^6$ Btu
<u>Iowa</u>					
All SMSAs	0.6	0.6	0.10	0.10	NSFS
Other Areas	0.8	0.8			
			0.6	0.6	H.I. $\leq 250 \times 10^6$ Potu
<u>Kansas</u>					
	0.60	0.60	0.60	0.60	Indirect Heating Equipment:
	1.026 (H.I.) ^{-0.233}	1.026 (H.I.) ^{-0.233}	1.026 (H.I.) ^{-0.233}	1.026 (H.I.) ^{-0.233}	H.I. per plant $\leq 10 \times 10^6$ Btu
	0.21	0.21			10 < H.I. < 10,000x10 ⁶ Btu
					H.I. = 1000
<u>Kentucky</u>					
Priority I AQCRs 72,77,78,79	0.56	0.56			H.I. per plant $\leq 10 \times 10^6$ Btu
	0.9634 (H.I.) ^{-0.236}	0.9634 (H.I.) ^{-0.236}			10 < H.I. < 10,000x10 ⁶ Btu
Priority II AQCRs 101,102,104	0.75	0.75			H.I. per plant $\leq 10 \times 10^6$ Btu
	1.2825 (H.I.) ^{-0.233}	1.2825 (H.I.) ^{-0.233}			10 < H.I. < 10,000x10 ⁶ Btu
Priority III AQCR 105	0.8	0.8			H.I. per plant $\leq 10 \times 10^6$ Btu
	1.3152 (H.I.) ^{-0.216}	1.3152 (H.I.) ^{-0.216}			10 < H.I. < 10,000x10 ⁶ Btu
			0.56	0.56	H.I. per plant $\leq 10 \times 10^6$ Btu
			0.9634 (H.I.) ^{-0.236}	0.9634 (H.I.) ^{-0.236}	10 < H.I. < 250
			0.10	0.10	H.I. per plant $\geq 250 \times 10^6$ Btu
<u>Louisiana</u>					
	0.6	0.6	0.6	0.6	

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Maine</u>	1.082 (H.I.) ^{-0.256} 0.3	1.082 (H.I.) ^{-0.256} 0.3	1.082 (H.I.) ^{-0.256} 0.3	1.082 (H.I.) ^{-0.256} 0.3	3 ≤ H.I. per stack ≤ 150x10 ⁶ Btu H.I. per stack > 150x10 ⁶ Btu
<u>Maryland</u> AQCRs 47,115	0.07	0.06			Existing Sources: Solid Fuel-Burning Installations: H.I. per boiler ≤ 200x10 ⁶ Btu: .050 gr/SCFD ^a H.I. per boiler > 200x10 ⁶ Btu: .030 gr/SCFD ^a Residual Oil-Burning Installations: H.I. per boiler ≤ 10x10 ⁶ Btu: .030 gr/SCFD ^a 10 < H.I. ≤ 50x10 ⁶ Btu: 0.025 gr/SCFD ^a 50 < H.I. < 200x10 ⁶ Btu: 0.020 gr/SCFD ^a H.I. > 200x10 ⁶ Btu: Existing or Modified: .020 gr/SCFD ^a New: .010 gr/SCFD ^a H.I. per boiler ≤ 10x10 ⁶ Btu 10 < H.I. < 10,000x10 ⁶ Btu New Solid Fuel Sources: .03 gr/SCFD ^a New Residual Oil Sources: See Above
Other AQCRs	0.60 1.026 (H.I.) ^{-0.233}	0.60 1.026 (H.I.) ^{-0.233}	0.02 0.07	0.02	
<u>Massachusetts</u> Berkshire, C. MA, Merrimack Valley, Metro. Boston, Pioneer Valley, SE MA APCDs Other Areas	0.12 0.15	0.12 0.15	0.10 0.05	0.10 0.05	H.I. per plant > 3x10 ⁶ Btu H.I. per plant > 3x10 ⁶ Btu 3 ≤ H.I. ≤ 250x10 ⁶ Btu and units w/SO ₂ control H.I. per plant > 250x10 ⁶ Btu Note: Ash content > 9% not permitted

^aCorrected to 50% excess air.

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - lb PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Michigan</u>					
Wayne Co.	0.20				Facilities firing pulverized coal: R = 3600 10 ³ lb st/hr: 0.15 lb/10 ³ lb stack gas
	0.86				Other Facilities: 0 < R ≤ 100 10 ³ lb st/hr: 0.65 lb/10 ³ lb stack gas
Other Areas	0.49				Facilities firing pulverized coal: 0 < R ≤ 115 10 ³ lb st/hr: 0.30 lb/10 ³ stack gas
	0.86				Other coal firing units: 0 < R ≤ 100 10 ³ lb st/hr: 0.65 lb/10 ³ lb stack gas R = Rated capacity, steam output in 1000 lb/hr
<u>Minnesota</u>					
AQCR 131, City of Duluth	0.4	0.4			
Other Areas	0.6	0.6			
			0.4	0.4	H.I. < 250x10 ⁶ Btu
			0.1	0.1	H.I. > 250x10 ⁶ Btu
<u>Mississippi</u>					
	0.60	0.60	0.60	0.60	H.I. per plant ≤ 10x10 ⁶ Btu
	0.8803 (H.I.) ^{-0.1565}	0.8803 (H.I.) ^{-0.1665}	0.8803 (H.I.) ^{-0.1665}	0.8803 (H.I.) ^{-0.1665}	10 < H.I. < 10,000x10 ⁶ Btu
	0.28	0.28			H.I. = 1000
<u>Missouri</u>					
Kansas City Metro. Area	0.60	0.60	0.60	0.60	H.I. per plant ≤ 10x10 ⁶ Btu
Kansas City, Springfield -	1.025 (H.I.) ^{-0.233}	1.026 (H.I.) ^{-0.233}	1.026 (H.I.) ^{-0.233}	1.026 (H.I.) ^{-0.233}	10 < H.I. < 10,000x10 ⁶ Btu
Green County Area	0.21	0.21			H.I. = 1000
Other Areas	0.60	0.60	0.60	0.60	H.I. per plant ≤ 10x10 ⁶ Btu
	.896 (H.I.) ^{-0.1743}	.896 (H.I.) ^{-0.1745}			10 < H.I. < 10,000x10 ⁶ Btu
			1.3072 (H.I.) ^{-0.3381}	1.3072 (H.I.) ^{-0.3381}	10 < H.I. < 2000x10 ⁶ Btu
			0.1	0.1	H.I. > 2000x10 ⁶ Btu

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Montana</u>	0.60 0.8803 (H.I.) ^{-0.1665} 0.21	0.60 0.8803 (H.I.) ^{-0.1665} 0.21	0.60 1.026 (H.I.) ^{-0.233} .10	0.60 1.026 (H.I.) ^{-0.233} .10	H.I. per stack ≤ 10x10 ⁶ Btu 10 < H.I. < 10,000x10 ⁶ Btu H.I. = 1000 NSPS
<u>Nebraska</u>	0.60 1.026 (H.I.) ^{-0.233}	0.60 1.026 (H.I.) ^{-0.233}	0.10	0.10	H.I. per plant ≤ 10x10 ⁶ Btu 10 < H.I. < 3800x10 ⁶ Btu NSPS
<u>Nevada</u>	0.6 1.02 (H.I.) ^{-0.231} 0.21	0.6 1.02 (H.I.) ^{-0.231} 0.21	0.6 1.02 (H.I.) ^{-0.231} .10	0.6 1.02 (H.I.) ^{-0.231} .10	Indirect Heat Transfer Fuel Burning Equipment H.I. per plant ≤ 10x10 ⁶ Btu 10 < H.I. < 4000x10 ⁶ Btu H.I. > 250x10 ⁶ Btu
<u>New Hampshire</u>	0.60 0.8803 (H.I.) ^{-0.1665}	0.60 0.8803 (H.I.) ^{-0.1665}	0.60 1.0286 (H.I.) ^{-0.2341} 0.10	0.60 1.0286 (H.I.) ^{-0.2341} 0.10	H.I. per stack ≤ 10x10 ⁶ Btu 10 < H.I. < 10,000x10 ⁶ Btu 10 < H.I. ≤ 250x10 ⁶ Btu H.I. > 250x10 ⁶ Btu
<u>New Jersey</u>					Fuel Burning Equipment H.I. Rate (10 ⁶ Btu/hr)
	0.6	0.6	0.6	0.6	1
	0.6	0.6	0.6	0.6	10
	0.15	0.15	0.15	0.15	100
	0.125	0.125	0.125	0.125	140
	0.11	0.11	0.11	0.11	180
	0.10	0.10	0.10	0.10	200
	0.10	0.10	0.10	0.10	> 200
					Emissions (1b/hr)
					0.6
					6.0
					15.0
					17.5
					19.3
					20.0
					0.1 (H.I.)

TABLE 1.35. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b PM/10 ⁵ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>New Mexico</u>	0.33 0.28 0.05		0.33 0.28 0.05		H.I.=100 H.I.=200 If aerodynamic dia. < 2 μm: 0.02 lb/10 ⁵ Btu H.I. > 250 x 10 ⁶ Btu H.I. > 1 x 10 ⁶ Btu/yr/unit
<u>New York</u>	0.60 .75-1.5 (H.I.)x10 ⁻³ 0.60 1.02 (H.I.) ^{-0.219}				Spreader Stokers 100 < H.I. ≤ 300x10 ⁶ Btu Other units < 10x10 ⁶ Btu 10 < H.I. < 10,000x10 ⁶ Btu H.I. per stack > 250x10 ⁶ Btu
<u>North Carolina</u>	0.6 1.0903(H.I.) ^{-0.2594} 0.18	0.6 1.0903 (H.I.) ^{-0.2594} 0.18	0.6 1.0903(H.I.) ^{-0.2594}	0.6 1.0903 (H.I.) ^{-0.2594}	H.I. per plant ≤ 10x10 ⁶ Btu 10 < H.I. < 10,000x10 ⁶ Btu H.I. = 1000
<u>North Dakota</u>	0.8	0.8	0.6 0.811 (H.I.) ^{-0.131}	0.6 0.811 (H.I.) ^{-0.131}	H.I. per plant ≤ 10x10 ⁶ Btu H.I. > 10x10 ⁶ Btu
<u>Ohio</u>	0.40 0.8003 (H.I.) ^{-0.3011} 0.10	0.40 0.8003 (H.I.) ^{-0.3011} 0.10	0.40 0.8003 (H.I.) ^{-0.3011} 0.10	0.40 0.8003 (H.I.) ^{-0.3011} 0.10	H.I. per plant ≤ 10x10 ⁶ Btu 10 < H.I. < 1000x10 ⁶ Btu H.I. per plant ≥ 1000x10 ⁶ Btu
<u>Oklahoma</u> AQCRs 17,22,184,186	0.60 1.0903 (H.I.) ^{-0.2594} 0.18	0.60 1.0903 (H.I.) ^{-0.2594} 0.18	0.60 1.0903 (H.I.) ^{-0.2594}	0.60 1.0903 (H.I.) ^{-0.2594}	H.I. per boiler ≤ 10x10 ⁶ Btu 10 < H.I. < 10,000x10 ⁶ Btu H.I. = 1000
<u>Oregon</u>	0.49	0.43	0.24 0.1	0.21 0.1	Existing Sources: 0.2 gr/cf New Sources: 0.1 gr/cf Note: Corrected to 50% excess air NSPS

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b PM/10 ⁶ Btu					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Pennsylvania</u>					
City of Philadelphia	0.27	0.23			Existing Sources: 0.20 lb/10 ³ lb stack gas ^a
			0.13	0.12	New Sources: 0.10 lb/10 ³ lb stack gas ^a
Allegheny County	0.40	0.40	0.40	0.40	0.2 < H.I. per boiler ≤ 50x10 ⁶ Btu
	3.6 (H.I.) ^{-0.56}	3.6 (H.I.) ^{-0.56}	3.6 (H.I.) ^{-0.56}	3.6 (H.I.) ^{-0.56}	50 < H.I. < 850x10 ⁶ Btu
	0.08	0.08	0.08	0.08	H.I. per boiler ≥ 850x10 ⁶ Btu
Other Areas	0.40	0.40	0.40	0.40	2.5 < H.I. ≤ 50x10 ⁶ Btu
	3.6 (H.I.) ^{-0.56}	3.6 (H.I.) ^{-0.56}	3.6 (H.I.) ^{-0.56}	3.6 (H.I.) ^{-0.56}	50 < H.I. < 600x10 ⁶ Btu
	0.10	0.10	0.10	0.10	H.I. per boiler ≥ 600x10 ⁶ Btu
<u>Rhode Island</u>					
	0.2	0.2	0.2	0.2	1 < H.I. < 250x10 ⁶ Btu
	0.1	0.1	0.1	0.1	H.I. per plant ≥ 250x10 ⁶ Btu
<u>South Carolina</u>	0.8	0.8			H.I. per plant < 10x10 ⁶ Btu
	0.6	0.6	0.6	0.6	10 < H.I. < 300x10 ⁶ Btu H.I. per plant ≤ 300x10 ⁶ Btu
<u>South Dakota</u>					
	0.3		0.3		
<u>Tennessee</u>	0.60	0.60	0.60	0.60	H.I. per plant ≤ 10x10 ⁶ Btu
	1.0903 (H.I.) ^{-0.2549}	1.0903 (H.I.) ^{-0.2549}			10 < H.I. < 10,000x10 ⁶ Btu
			2.1617 (H.I.) ^{-0.5566}	2.1617 (H.I.) ^{-0.5566}	10 < H.I. < 250x10 ⁶ Btu
			0.10	0.10	H.I. per plant ≥ 250x10 ⁶ Btu
<u>Texas</u>					
	0.3		0.3		Plus state regs, not part of SIP
		0.1		0.1	H.I. > 2500x10 ⁶ Btu
<u>Utah</u>					
AQCR 220	0.60	0.60	0.60	0.60	H.I. per plant ≤ 10x10 ⁶ Btu
	0.87 (H.I.) ^{-0.16}	0.87 (H.I.) ^{-0.16}	0.87 (H.I.) ^{-0.16}	0.87 (H.I.) ^{-0.16}	10 < H.I. < 10,000x10 ⁶ Btu
	0.29	0.29	0.29	0.29	H.I. = 1000
					Note: Gen. Reg. for Coal-Fired Generators: 85% Control of Potential Emissions
			0.10	0.10	NSPS

^aCorrected to 12% CO₂ by volume

^aCorrected to 12% CO₂ by volume

TABLE 1.33. Particulate Matter Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions - lb PM/10 ⁶ Btu				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Vermont</u>	0.50 1.4865 (H.I.) ^{-0.4732} 0.10	0.50 1.4865 (H.I.) ^{-0.4732} 0.10	0.06	0.06	H.I. per stack $\leq 10 \times 10^6$ Btu 10 < H.I. < 300×10^6 Btu H.I. per stack $\geq 300 \times 10^6$ Btu H.I. per stack > 1000×10^6 Btu
<u>Virginia</u>	0.40 0.8425 (H.I.) ^{-0.2314}	0.40 0.8425 (H.I.) ^{-0.2314}	0.10	0.10	H.I. per plant < 25×10^6 Btu 25 < H.I. < $10,000 \times 10^6$ Btu NSPS
<u>Washington</u>					
AQCR 229	0.24	0.21	0.12	0.11	Existing Sources: 0.10 gr/SCFD New Sources: 0.05 gr/SCFD
Whatcom, Skagit, San Juan, Island Counties			0.12		Residual Oil: 0.10 gr/SCFD Other Fuel: 0.05 gr/SCFD
Other Areas	0.24	0.21	0.24	0.21	Existing and New Sources: 0.10 gr/SCFD
<u>West Virginia</u>	0.05	0.05	0.05	0.05	Electric Power Plants: 0.05 (H.I.) lb/hr Max. discharge rate: 1200 lb/hr Industrial Furnaces: 0.09 (H.I.) lb/hr Max. discharge rate: 600 lb/hr
<u>Wisconsin</u>					
AQCR 237	0.30	0.30			
AQCR 239		0.15			< 250×10^6 Btu cannot burn coal
Other AQCRs	0.60	0.60	0.15 0.10	0.15 0.10	H.I. per stack $\leq 250 \times 10^6$ Btu H.I. per stack > 250×10^6 Btu
<u>Wyoming</u>	0.60 0.8963 (H.I.) ^{-0.1743}	0.60 0.8963 (H.I.) ^{-0.1743}	0.10	0.10	H.I. per plant $\leq 10 \times 10^6$ Btu 10 < H.I. < 10,000

TABLE 1.34. Particulate Regulations As They Apply
To New Fuel Combustion Sources

Minimum Size Requirement (Heat Input) 10 ⁶ Btu	Maximum Emissions lbs/10 ⁶ Btu				Total
	≤ .10	.11-.30	.31-.60	> .60	
None	7	3	1	2	13
≥ 1	1	1	-	-	2
> 150	-	1	-	-	1
> 200	1	-	-	-	1
≥ 250	21	4	2	-	27
≥ 600	1	-	-	-	1
≥ 1000	2	-	-	-	2
≤ 1300	-	-	1	-	1
≥ 2000	1	-	-	-	1
> 2500	1	-	-	-	1
TOTAL	35	9	4	2	50

NOTE: Arkansas expresses regulation as concentration limits only; therefore, is not included.

TABLE 1.35. Particulate Emission Regulations for Incinerators (Multiple Chamber)³¹

Location	Charging Rate (lb/hr)	Refuse Type	Emissions, Corrected to 12% CO			Note
			GR/SCF	lb/hr	lb/1000 lb gas	
Alabama	≤ 50 tpd					.20 lb/100 lb. refuse
	> 50 tpd					.10 lb/100 lb. refuse NSPS apply
Alaska	≤ 200		0.3			
	200-1000		0.2			
	> 1000		0.1			
Arizona					0.17	
Arkansas	< 200		0.3			
	≥ 200		0.2			
California						
Colorado						
	In a.p. control areas		0.10			
	Outside control areas		0.15			
	> 50 tpd		0.08			Max. 2-hr average
Connecticut			0.08			
Delaware	100			0.2		
	200			0.4		
	300			0.6		
	400			0.8		
	500			1.0		
	1000			2.0		
	2000			3.5		
	3000			5.0		
D.C.			0.03			New incinerators prohibited after 7/4/75.
			0.08			District-owned incinerators
Florida	≥ 50 tpd		0.08			Corrected to 50% excess air
Georgia	≤ 50 tpd	0,1,2	0.10			
		3,4,5,6	0.20			
	> 50 tpd		0.08			

TABLE 1.35. Particulate Emission Regulations for New Incinerators (Multiple Chamber) (Contd.)³¹

Location	Charging Rate (lb/hr)	Refuse Type	Emissions, Corrected to 12% CO		
			GR/SCF	lb/hr	lb/1000 lb gas
Hawaii					0.20 lb/100 lb refuse
Idaho	>50 tpd		0.80		0.2 lb/100 lb refuse
Illinois	>60,000		0.05		
	2000-60,000		0.08		
	<2000		0.1		
		Wood waste	0.2		
Indiana	<1000			0.7	Corrected to 50% excess air
	>1000			0.4	
Iowa	>50 tpd				NSPS apply
	<1000		0.35		
	>1000		0.2		
Kansas	<200		0.3		
	200-2000		0.2		
	>2000		0.1		
Kentucky	>50 tpd		0.08		
	≤50 tpd		0.2		
Louisiana			0.2		
Maine	≤50 tpd		0.2		Class III, IV, V, VI, VII
	>50 tpd		0.08		
Maryland					
Massachusetts			.05		Municipal
			.10		Commercial, industrial, residential
Michigan	0-100			0.65	Residential
				0.30	apts.
				0.30	commercial, industrial
				0.20	Municipal
					Pathological, manure drying

TABLE 1.35. Particulate Emission Regulations for New Incinerators (Multiple Chamber) (Contd.)³¹

Location	Charging Rate (lb/hr)	Refuse Type	Emissions, Corrected to 12% CO			Note
			GR/SCF	lb/hr	lb/1000 lb gas	
Minnesota	<200		0.2			
	200-2000		0.15			
	2000-4000		0.1			
	>4000		0.08			
Mississippi "Close proximity to residential area"			0.2			
			0.1			
Missouri	<200		0.3			New incin- erators
	>200		0.2			
Montana			0.10			
Nebraska	<2000		0.2			
	>2000		0.1			
Nevada	<2000					3 lb/1000 lb refuse
	>2000					40.7 x 10 ⁻⁵ X (rate of charge)
New Hampshire	<200		0.3			
	>200		0.2			
	>50 tpd		0.08			
		Sewage Sludge				1.30 lb/1000 input
New Jersey	<2000	0,1,2,3	0.2			
	>2000	4,5,6	0.1			
New Mexico						
New York	<2000					See Figure 1 in Regs.
	>2000					
North Carolina	0-100			0.2		
	200			0.4		
	500			1.0		
	1000			2.0		
	>2000			4.0		

TABLE 1.35. Particulate Emission Regulations for New Incinerators (Multiple Chamber) (Contd.)³¹

Location	Charging Rate (lb/hr)	Refuse Type	Emissions, Corrected to 12% CO			Note
			GR/SCF	lb/hr	lb/1000 lb gas	
Utah	>50 tpd		0.08			
Vermont						0.10 lb/100 lb refuse
Virginia			0.08			NSPS apply
Washington			0.10			Corrected to 7% oxygen NSPS apply
West Virginia						E(lb/hr) = Fx Inc. Capacity (tons/hr) where F = 8.25 I.C. $\leq$ 200 lb/hr 5.43 I.C. 200-15,000 lb/hr 2.72 I.C. > 15,000 lb/hr
Wisconsin	≤ 500				0.30	
	500-4000				0.20	
	> 4000				0.15	
Wyoming	(Process Rate)					See Sec 14.g
	50			0.36		
	100			0.55		
	500			1.53		
	1000			2.25		
	5000			6.34		
	10,000			9.73		

TABLE 1.35. Particulate Emission Regulations for New Incinerators (Multiple Chamber)(Contd.)³¹

Location	Charging Rate (lb/hr)	Refuse Type	Emissions, Corrected to 12% CO			Note
			GR/SCF	lb/hr	lb/1000 lb gas	
North Dakota	10			0.0409		
	20			0.0763		
	30			0.109		
	40			0.142		
	50			0.174		
	100			0.333		
	500			1.38		
	1000			2.58		
	5000			7.58		
	10,000			12.1		
	50,000			35.5		
	100,000			56.4		
Ohio	<100					0.2 lb/100 lb refuse
	≥100					0.10 lb/100 lb refuse
Oklahoma	≥100					See Figure in Regs.
Oregon	<200		0.3			
	>200		0.1			
	>50 tpd		0.08			
Pennsylvania			0.1			
Puerto Rico	<50 tpd					0.40 lb/100 lb refuse
	≥50 tpd					0.20 lb/100 lb refuse
Rhode Island	<2000	0,1,2,3	0.16			
	≥2000	4,5,6	0.08			
South Carolina						0.5 lb/10 ⁶ Btu
South Dakota						0.20 lb/100 lb refuse
		Wood waste	0.2			
Tennessee	<2000					0.2% of charging rate
	>2000					0.1% of charging rate
Texas						See Rule 105.1

Type 2 - Refuse, up to 50% moisture, 7% incombustible solids; heating value of 4,300 Btus per lb as fired.

Type 3 - Garbage, up to 70% moisture, 5% incombustible solids; heating value of 2,500 Btus per lb as fired.

Type 4 - Human and animal remains, up to 85% moisture, 5% incombustible solids; heating value of 100 Btus per lb as fired.

Type 5 - By-product waste.

Type 6 - Solid by-product waste.

● *SO₂ Limitations for Combustion Sources.* In about one-third of the states, the size of the source determines if the source must meet SO₂ emission restrictions. Source size usually is expressed by heat input in 10⁶ Btu/lb (MM Btu/lb). Occasionally steam generation rates, concentrations or annual emissions are used. Federal NSPS emission limitations apply to boilers greater than 250 x 10⁶ Btu. This represents a generating capacity of about 25 megawatts. The NSPS is 1.2 #S/10⁶ Btu heat input for coal-fired units and .8 #S/10⁶ Btu heat input for oil-fired units.

While state regulations cannot be less stringent than NSPS, they can be more stringent. State regulations may also apply to all sources or to units with lower heat inputs.

As with NSPS, many states use more than one regulation for controlling SO₂ emissions, and about 35% of the states segregate new and existing sources. About a third of the states also segregate fuel use.

Often oil is more stringently regulated because of the ease of sulfur content control in oil. In a few states, (primarily in the northeast) soil fuel restrictions have essentially banned the use of coal without flue gas desulfurization. Table 1.36³² presents state and local SO₂ emissions limitations, and Table 1.37 summarizes regulations for new sources by boiler size.

● *Nitrogen Oxide Emission Limitations from Combustion Sources.* Nitrogen oxides as previously mentioned are common atmospheric pollutants. Their presence is usually associated with high temperature combustion followed by rapid cooling. Of the six oxides of nitrogen (NO, NO₂, N₂O, N₂O₃, N₂O₄, N₂O₅) only nitric oxide, NO, and nitrogen dioxide are of prime concern. Several short-term and long-term exposure studies indicate problems associated with lungs

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions - lb SO ₂ /10 ⁶ BTU, Unless Noted				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Alabama</u>					
Class I Counties	1.8	1.8			
Class II Counties	4.0	4.0			
			1.2	.8	NSPS
<u>Alaska</u>					500 ppm SO ₂ for all fuel-burning equipment (Coal-1.4; Oil-1.25 lb SO ₂ /10 ⁶ Btu)
<u>Arizona</u>	1.0	1.0	0.8	0.8	New = Constructed after 8/17/71
<u>Arkansas</u>					AAQS - 0.2 ppm SO ₂
<u>California</u>					
AQCRs 23,31					2000 ppm SO ₂ ^a
AQCRs 24,25,29,32					0.5% S (Coal-.83; Oil-.54 lb SO ₂ /10 ⁶ Btu)
AQCR 26					1000 ppm SO ₂ ^a
AQCR 27					
Lassen, Madoc County					0.5% S
E. Shasta County					1500 ppm SO ₂ ^a
Siskiyou County					2000 ppm SO ₂ ^a
AQCR 28					
Tehama County					0.5% S ^a
Plumas, W. Shasta County					1000 ppm SO ₂ ^a
Other Counties					2000 ppm SO ₂ ^a
AQCR 30					300 ppm SO ₂ ^a
AQCR 33					
Imperial, E. Riverside, N.E. San Bernadino Counties					0.5% S
E. San Diego County					500 ppm SO ₂ ^a
E. Kern, N.E. Los Angeles Counties					2000 ppm SO ₂ ^a
<u>Colorado</u>					
			1.2	0.8	NSPS

^aCorrected to 50% excess air

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - lb SO ₂ /10 ⁶ BTU, Unless Noted					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Connecticut</u>	0.55	0.55	0.55	0.55	With Stack-gas cleaning, otherwise 0.5% S
<u>Delaware</u>					0.3% S - distillate oil (0.3 lb SO ₂ /10 ⁶ Btu) 1.0% S - other fuels burned in New Castle County
<u>Dist. of Columbia</u>					(Coal-1.67; Oil-1.09 lb SO ₂ /10 ⁶ Btu) 0.5% S (Coal-.83; Oil-.54 lb SO ₂ /10 ⁶ Btu)
<u>Florida</u>	1.5	1.1	1.2	0.8	H.I. per plant > 250x10 ⁶ Btu H.I. per plant < 250x10 ⁶ Btu "Latest reasonably available technology"
<u>Georgia</u>			1.2	0.8	Existing Sources: H.I. per boiler < 100x10 ⁶ Btu: 2.5% S H.I. per boiler > 100x10 ⁶ Btu: 3.0% S
<u>Hawaii</u>					H.I. per plant > 250x10 ⁶ Btu: 0.5% S (Coal-.83; Oil-.54 lb SO ₂ /10 ⁶ Btu) Other fuel-burning equipment: 2.0% S
<u>Idaho</u>					Coal: 1.0% S #1 Distillate Oil: 0.3% S #2 Distillate Oil: 0.5% S #4-#6 Residual Oil: 1.75% S MSPS
<u>Illinois-MMAs</u>	1.8		1.2	0.8	
Other Areas	6.0	0.3 1.0	1.8 1.2	0.3 1.0 0.8	Distillate Oil Residual Oil H.I. per boiler < 250x10 ⁶ Btu H.I. per boiler > 250x10 ⁶ Btu Distillate Oil - all size boilers Residual Oil - H.I. per boiler < 250x10 ⁶ Residual Oil - H.I. per boiler > 250x10 ⁶

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions - lb SO ₂ /10 ⁶ BTU, Unless Noted				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Indiana</u>	17(H.I.) ^{-0.33}	17(H.I.) ^{-0.33}	17(H.I.) ^{-0.33}	17(H.I.) ^{-0.33}	All existing sources; new sources ≤ 250 x 10 ⁵ Btu. 1.2 ≤ E ≤ 6.0
			1.2	0.8	H.I. per plant > 250x10 ⁶ Btu
<u>Iowa</u>	8.0	2.5			H.I. > 500 x 10 ⁶ Btu
Black Hawk, Clinton,	6.0	2.5			H.I. per boiler > 250x10 ⁶ Btu:
Des Moines, Dubuque, Jackson					1.5 lb S/10 ⁶ Btu
Lee, Linn, Louisa, Muscotine			6.0	2.5	H.I. < 250 x 10 ⁶ Btu.
Scott Counties			1.2	0.8	NSPS
<u>Kansas</u>					H.I. per boiler > 250x10 ⁶ Btu: 1.5 lb S/10 ⁶ Btu (30 lb SO ₂ /10 ⁶ Btu)
<u>Kentucky</u>	4.0	2.5	4.0	2.5	H.I. per plant ≤ 10x10 ⁶ Btu
Priority I AQCRs	1.2	0.8			H.I. > 250x10 ⁶ Btu
Priority II AQCRs	2.0	1.5			H.I. > 500x10 ⁶ Btu
Priority III AQCRs	3.5	2.0	9.46 (H.I.) -0.3740	5.56 (H.I.)-0.3540	H.I. > 1000x10 ⁶ Btu
			1.2	0.8	10 < H.I. ≤ 250x10 ⁶ Btu
					H.I. > 250x10 ⁶ Btu
<u>Louisiana</u>				5.0	All Sources: 2000 ppm SO ₂ (Coal-5.7; Oil-5.0 lb SO ₂ /10 ⁶ Btu)
<u>Maine</u>					2.5% S
AQCRs 107,108,109,111					1.5% S (Coal-2.5; Oil-1.6 lb SO ₂ /10 ⁶ Btu)
AQCR 110					Sources with equipment to reduce SO ₂ emission level to equivalent of burning 1.5% S fuel are exempt.
<u>Maryland</u>					Solid Fuels, H.I. per plant > 100x10 ⁶ Btu: 1.0% S (1.67 lb SO ₂ /10 ⁶ Btu)
					Residual Oil: 1.0% S (1.09 lb SO ₂ /10 ⁶ Btu)
					Distillate Oil: 0.3% S (.33 lb SO ₂ /10 ⁶ Btu)
<u>Massachusetts</u>					
Metro Boston APCD					H.I. per plant ≤ 2500x10 ⁶ Btu: 0.28 lb S/10 ⁶ Btu (.56 lb SO ₂ /10 ⁶ Btu)

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - lb SO ₂ /10 ⁶ BTU, Unless Noted					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
AQCR 119 excluding Boston APCD					H.I. per plant > 100x10 ⁶ Btu: 1.21 lb S/10 ⁶ Btu (2.42 lb SO ₂ /10 ⁶ Btu)
Other Areas					Other Areas: 0.55 lb S/10 ⁶ Btu (1.1 lb SO ₂ /10 ⁶ Btu) #2 Fuel Oil: 0.17# S/10 ⁶ Btu (.34 lb SO ₂ /10 ⁶ Btu) Solid or Liquid Fuels: 7/1/75 Plant Capacity ≤ 500,000 lb steam/hr. 2.0% S Plant Capacity > 500,000 lb steam/hr 1.5% S 7/1/78 Plant Capacity ≤ 500,000 lb steam/hr 1.5% S Plant Capacity > 500,000 lb steam/hr 1.0% S
<u>Michigan</u>					
Wayne Co.-8/1/76					Pulverized Coal 1.0% S (1.67 lb SO ₂ /10 ⁶ Btu) Other Coal 0.5% S (0.83 lb SO ₂ /10 ⁶ Btu) #1, #2 Oil 0.3% S (0.33 lb SO ₂ /10 ⁶ Btu) #4, #5, #6 Oil 0.7% S (0.76 lb SO ₂ /10 ⁶ Btu)
<u>Minnesota</u>					
AQCRs 127,128,129,130, 132,133	4.0	2.0	1.2	0.8	H.I. > 250x10 ⁶ Btu
AQCR 131	4.0	2.0	1.0	2.0	H.I. < 250x10 ⁶ Btu
	3.0	1.6	1.2	0.8	H.I. > 250x10 ⁶ Btu
<u>Mississippi</u>	4.8	4.8	4.8	4.8	
	2.4	2.4	2.4	2.4	Modified unit < 250x10 ⁶ Btu
<u>Missouri</u>					Max. Emission rate = 1000 lb SO ₂ /hr
AQCR 70					H.I. per plant < 2000x10 ⁶ Btu: 2.0% S (Coal-3.33; Oil-2.18 lb SO ₂ /10 ⁶ Btu) 1.0 lb S/10 ⁶ Btu (2.0 lb SO ₂ /10 ⁶ Btu)
<u>Montana</u>					NSPS
<u>Nebraska</u>	2.5	2.5	1.2	0.8	NSPS apply
			1.2	0.8	H.I. > 250x10 ⁶ Btu
<u>Nevada</u>					H.I. per plant ≤ 250x10 ⁶ Btu: 0.7 (H.I.) lb S/hr H.I. per plant > 250 x 10 ⁶ BTU: 0.105 (H.I.) lb S/hr
			1.2	0.8	NSPS

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - lb SO ₂ /10 ⁶ BTU, Unless Noted					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>New Hampshire</u>					
					Existing Sources: Coal: Max. emission - 2.8 lb S/10 ⁶ Btu Max. 3-mo. ave. - 2.0 lb S/10 ⁶ Btu Oil: #2 - 0.4% S (0.44 lb SO ₂ /10 ⁶ Btu) #4 - 1.0% S (1.09 lb SO ₂ /10 ⁶ Btu) #5, #6 - AOCR 107 - 2.2% S (2.4 lb SO ₂ /10 ⁶ Btu) Other areas - 1.5% S (1.6 lb SO ₂ /10 ⁶ Btu) New Sources: NSPS or Coal: Max emission - 1.5 lb S/10 ⁶ Btu Max 3-mo. avg. - 1.0 lb S/10 ⁶ Btu Oil: Same as existing source reg.
			1.2	0.8	
<u>New Jersey</u>					
Atlantic, Cape May					Bituminous Coal: 1.0% S (1.67 lb SO ₂ /10 ⁶ Btu) Bituminous Coal with FGD and State approval
Cumberland, Hunterdon	1.5				Anthracite Coal: 0.7% S (1.17 lb SO ₂ /10 ⁶ Btu) Anthracite Coal with FGD and State approval
Ocean, Sussex, Warren Counties					Effective 10/1/71 Coal: 0.2% S (dry basis) (0.33 lb SO ₂ /10 ⁶ Btu) Oil: #2 - 0.2% S (0.22 lb SO ₂ /10 ⁶ Btu) #4, 5, 6 - 0.3% S* (0.33 lb SO ₂ /10 ⁶ Btu) *N/A if emissions < 0.3 lb SO ₂ /10 ⁶ Btu
Other Areas	1.0				
<u>New Mexico</u>					
	1.0				H.I. > 3x10 ⁶ Btu
			0.34		H.I. per boiler > 250x10 ⁶ Btu
		0.34		0.34	H.I. per boiler > 1x10 ⁶ Btu

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Allowable Emissions - 1b SO ₂ /10 ⁶ BTU, Unless Noted					
Location	Existing Sources		New Sources		Note
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>New York</u>					Coal: $\leq 1 \times 10^5$ Btu - .75% S
NYC					Solid Fuel: 0.2 lb S/10 ⁶ Btu Distillate Oil: 0.2% S Other Oil: 0.3% S
Nassau, Rockland, Westchester Counties					Solid Fuel: 0.2 lb S/10 ⁶ Btu Oil: 0.37% S
Suffolk County					Solid Fuel: 0.6 lb S/10 ⁶ Btu Oil: 1.0% S; H.I. $> 250 \times 10^6$ Btu - .75% S
Erie, Niagara Counties					Solid Fuel: 1.7 lb S/10 ⁶ Btu 3-mo. ave: 1.4 lb S/10 ⁶ Btu Oil: 1.1% S
Other Areas					Solid Fuel: 2.5 lb S/10 ⁶ Btu 3-mo. ave: 1.9 lb S/10 ⁶ Btu Oil: 2.0% S
<u>North Carolina</u>	2.3	2.3	1.2 1.6	0.8 1.6	NSPS: also Solid Fuel: 2.8 lb S/10 ⁶ Btu for H.I. $< 10.0 \times 10^6$ Btu Oil: .3% S for H.I. $< 250 \times 10^6$ Btu
<u>North Dakota</u>	3.0	3.0	3.0	3.0	After 7/1/80 Fuel-burning installations
<u>Ohio</u>	1.0	1.0	1.0	1.0	
<u>Oklahoma</u>					Existing Sources: Max. 5-min period - .52 ppm SO ₂ Max. 1-hr ave - .46 ppm SO ₂ Max. 3-hr ave - .25 ppm SO ₂ Max. 24-hr ave - .05 ppm SO ₂
			1.2	0.8	
<u>Oregon</u>					Existing Sources: 1000 ppm SO ₂ Coal: 1.0% S
AQCR 193					Residual Oil: 1.75% S #1 Oil: 0.3% S #2 Oil: 0.5% S
AQCRs 190,191,192,194					150 < H.I. per boiler $< 250 \times 10^6$ Btu H.I. per boiler $> 250 \times 10^6$ Btu; NSPS
			1.6	1.4	
			1.2	0.8	

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions - 1b SO ₂ /10 ⁶ BTU, Unless Noted				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Pennsylvania</u>					
Beaver Valley, Monongahela	1.0	1.0	1.0	1.0	2.5 < H.I. per boiler < 50x10 ⁶ Btu
Valley, SE Pa Air Basin	1.7(H.I.) ^{-0.14}	1.7(H.I.) ^{-0.14}	1.7(H.I.) ^{-0.14}	1.7(H.I.) ^{-0.14}	50 < H.I. < 2000x10 ⁶ Btu
Allegheny County	0.60	0.60	0.60	0.60	H.I. ≥ 2000x10 ⁶ Btu
Other Air Basins	3.0	3.0	3.0	3.0	2.5 < H.I. per boiler < 50x10 ⁶ Btu
	5.1(H.I.) ^{-0.14}	5.1(H.I.) ^{-0.14}	5.1(H.I.) ^{-0.14}	5.1(H.I.) ^{-0.14}	50 < H.I. < 2000x10 ⁶ Btu
	1.9	1.9			H.I. = 1000
<u>Rhode Island</u>	1.1	1.1	1.1	1.1	With stack-gas cleaning and state approval, otherwise 0.55 lb S/10 ⁶
<u>South Carolina</u>					
Class I Counties	3.5	3.5	3.5	3.5	H.I. per plant ≤ 10x10 ⁶ Btu
	2.3	2.3	2.3	2.3	H.I. per plant > 10x10 ⁶ Btu
Class II Counties	3.5	3.5	3.5	3.5	H.I. per plant ≤ 1000x10 ⁶ Btu
	2.3	2.3			H.I. per plant > 1000x10 ⁶ Btu
Class III Counties	3.5	3.5	3.5	3.5	All fuel-burning sources
<u>South Dakota</u>	3.0	3.0	3.0	3.0	Fuel-burning installations
<u>Tennessee</u>					
Class I Counties	1.6	1.6			H.I. per plant < 1000x10 ⁶ Btu
Class I,II Counties	1.2	1.2			H.I. per plant > 1000x10 ⁶ Btu
Class II Counties	3.0	3.0			H.I. per plant < 1000x10 ⁶ Btu
Class III Counties	4.0	4.0			
Class I Counties			1.6	1.6	H.I. per plant < 250x10 ⁶ Btu
Class II Counties			3.0	3.0	H.I. per plant < 250x10 ⁶ Btu
Class III Counties			4.0	4.0	H.I. per plant < 250x10 ⁶ Btu
			1.2	0.8	H.I. per plant ≥ 250x10 ⁶ Btu
<u>Texas</u>					
AQCRs 106,153,210,211	3.0		3.0		
214,216,218		1.1		1.1	Liquid Fuel - 440 ppm SO ₂
Galveston, Harris Counties					Max. gr. level conc., 30-min ave: 28 ppm
Jefferson, Orange Counties					Max. gr. level conc., 30-min ave: .32 ppm NSPS
			1.2	0.8	

TABLE 1.36. Sulfur Oxides Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions - lb SO ₂ /10 ⁶ BTU, Unless Noted				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
<u>Utah</u>	1.67	1.63	1.2	0.8	Existing Sources: Coal: 1.0% S Oil: 1.5% S NSPS
<u>Vermont</u>					All Fuels: 2.0% S. (Coal-3.3; Oil-2.18 lb SO ₂ /10 ⁶ Btu)
<u>Virginia</u>					2.64 K lb SO ₂ /hr
Regions not meeting NAAQS					1.58 K or 1.06 K lb SO ₂ /hr
AQCR 47			1.2	0.8	1.06 K lb SO ₂ /hr (1.06 lb SO ₂ /10 ⁶ Btu) K = total rated capacity of plant NSPS
<u>Washington</u>					All Sources: 1000 ppm SO ₂ Coal-1.95; Oil-1.8 lb SO ₂ /10 ⁶ Btu Note: Emissions corrected to 7% oxygen in exhaust gas
<u>West Virginia</u>					Power Plants: Eff. 6/30/75 - 2.7 K lb SO ₂ /hr Eff. 6/30/78 - 2.0 K lb SO ₂ /hr Other Combustion Units: Eff. 6/30/75 - 3.1 K lb SO ₂ /hr Eff. 6/30/78 - 2.3 K lb SO ₂ /hr All plants - 6/30/75 3.2 K lb SO ₂ /hr Power Plants - 6/30/78 2.0 K lb SO ₂ /hr Others - 6/30-78 - 2.3 K lb SO ₂ /hr Power Plants - 1.6 K lb SO ₂ /hr Max. emissions - 45,000 lb SO ₂ /hr Others - 1.6 K lb SO ₂ /hr Max. emissions - 5,500 lb SO ₂ /hr K = total design H.I. for plant H.I. for boiler >250x10 ⁶ Btu H.I. < 250x10 ⁶ Btu 250 < H.I. per boiler < 2500x10 ⁶ Btu H.I. > 250x10 ⁶ Btu
EPA Priority I,II Regions					
EPA Priority III Region					
State Region IV					
<u>Wisconsin</u>			1.2	0.8	
AQCR 239			1.1		
<u>Wyoming</u>	1.2		0.2	0.8	

TABLE 1.37. State SO₂ Regulations As They Apply To New Fuel Combustion Sources

Minimum Size Requirement (Heat Input) 10 ⁶ Btu	Maximum Emissions from Solid Fuel (lbs/10 ⁶ Btu)					Maximum Emissions for Liquid Fuel (lbs/10 ⁶ Btu)				
	< .50	.51-.80	.81-1.2	> 1.2	Total No. of States	< .50	.51-.80	.81-1.2	> 1.2	Total No. of States
None	1	2	7	10	20	4	6	2	9	21
> 1	-	-	-	-	-	1	-	-	-	1
> 10	-	-	-	1	1	-	-	-	1	1
> 100	-	-	-	1	1	-	-	-	-	0
< 250	-	-	-	1	1	-	-	-	1	1
> 250	2	-	20	1	23	1	20	-	1	22
< 2000	-	-	-	1	1	-	-	-	1	1
> 2000	-	1	-	-	1	-	1	-	-	1
< 2500	-	1	-	-	1	1	-	-	-	1
TOTAL					49					49

NOTE: Arkansas expresses regulations as concentration limits only.

with alteration of circulatory and respiratory systems associated with long-term exposure. Odor perception of NO_2 is about 50% at $225 \mu\text{g}/\text{m}^3$ (.12 ppm). Epidemiological studies also show that NO_2 concentrations can be correlated with increased respiratory disease at mean 24 hr concentrations of between .062 and .109 ppm.

As a result of positively correlated material damage, animal and human health effects, the federal government imposed a primary and secondary standard of .05 ppm ambient air quality standard for oxides of nitrogen (measured as NO_2). Similarly, federal new source performance standards placed emission limitations on fossil-fired steam generators.

As a response to national ambient air quality standards, states developed state implementation plans which included, for the most part, emission limitations equal to the NSPS for NO_x . In many states, however, additional limitations were placed on boilers less than the 250×10^6 Btu/hr cutoff imposed by federal regulations. Table 1.38 presents state emission limitations on nitrogen oxide emissions. Table 1.39 summarizes the distribution of state emission limitations by boiler size.

- *Hydrocarbon Emission Limitations.* Hydrocarbons at concentrations normally found in the environment are in themselves nonirritating. Hydrocarbon standards have been established primarily because HC is instrumental in the production of more irritating compounds present in photochemical smog. Formation of photochemical oxidants are a result of nitrogen oxides, sunlight and hydrocarbon compounds.

Federal air quality standards have been set to maintain oxidant levels below .08 ppm. Hydrocarbon concentrations are limited to .24 ppm over a three hour period. Of the 32×10^6 tons of annual hydrocarbon emissions, about 52% come from transportation sources. Only 2.2% comes from stationary fuel combustion. Over half of that 2% is from combustion of wood with oil, coal and gas combustion contributing less than 1.1% of the national hydrocarbon emissions. Because of their small contribution, power generating facilities are not subject to direct federal regulation.

State regulation of hydrocarbon emissions are associated with internal combustion engines which is discussed later in this chapter. State new source review regulations could impact any new hydrocarbon sources in specific localities such as Los Angeles. Such new source reviews, however, are not expected to effect ICES developments.

TABLE 1.38. Nitrogen Oxides Emission Regulations for
Fuel Combustion Sources³³

Location	Allowable Emissions (lb/10 ⁶ Btu)				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
Alabama			0.7	0.30	≥ 250 x 10 ⁶ Btu
Alaska					
Arizona			0.70	0.30	
Arkansas					
California					
Colorado			0.70	0.30	≥ 250 x 10 ⁶ Btu
Connecticut	0.9	0.30	0.7	0.30	≥ 250 x 10 ⁶ Btu 5-250 x 10 ⁶ Btu: same unless ex- cepted by Com- missioner.
Delaware					
D.C.	0.70	0.30	0.70	0.30	> 100 x 10 ⁶ Btu
Florida			0.70	0.30	> 250 x 10 ⁶ Btu
Georgia			0.7	0.3	≥ 250 x 10 ⁶ Btu
Hawaii					
Idaho			0.70	0.30	≥ 250 x 10 ⁶ Btu
Illinois			0.7	0.30	≥ 250 x 10 ⁶ Btu
Chicago, St. Louis, MMAS	0.9	0.3			
Indiana	0.70	0.30	0.70	0.30	≥ 250 x 10 ⁶ Btu. Existing sources in "Basin Prior- ity A" only.
Iowa			0.70	0.30	> 250 x 10 ⁶ Btu
Kansas	0.90	0.30	0.90	0.30	≥ 250 x 10 ⁶ Btu
Kentucky			0.70	0.30	≥ 250 x 10 ⁶ Btu
Louisiana					

TABLE 1.38. Nitrogen Oxides Emission Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions (lb/10 ⁶ Btu)				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
Maine					
Maryland					
Massachusetts				0.3	> 250 x 10 ⁶ Btu. Doesn't indicate fuel.
Michigan					
Minnesota			0.7	0.3	> 250 x 10 ⁶ Btu
Mississippi					
Missouri					
Montana			0.7	0.3	≥ 250 x 10 ⁶ Btu
Nebraska			0.7	0.3	> 250 x 10 ⁶ Btu
Nevada			0.7	0.3	> 250 x 10 ⁶ Btu
New Hampshire					
New Jersey					
New Mexico	.7	.3	.45	.3	> 250 x 10 ⁶ Btu > 1 x 10 ⁶ Btu
New York			0.70	0.30	> 250 x 10 ⁶ Btu
North Carolina	1.3	0.6	1.3	0.6	≥ 250 x 10 ⁶ Btu
North Dakota					
Ohio	0.9	0.30	0.9	0.30	≥ 250 x 10 ⁶ Btu. Existing sources in Priority I re- gions.
Oklahoma			0.70	0.30	≥ 50 x 10 ⁶ Btu
Oregon			0.70	0.30	> 250 x 10 ⁶ Btu
Pennsylvania					
Puerto Rico					

TABLE 1.38. Nitrogen Oxides Emission Regulations for Fuel Combustion Sources (Contd.)

Location	Allowable Emissions (lb/10 ⁶ Btu)				Note
	Existing Sources		New Sources		
	Solid Fuel	Liquid Fuel	Solid Fuel	Liquid Fuel	
Rhode Island					
South Carolina					
South Dakota		0.30		0.30	
Tennessee			0.70	0.30	<u>≥</u> 250 x 10 ⁶ Btu
Texas					
Utah			0.70	0.30	<u>≥</u> 250 x 10 ⁶ Btu
Vermont				0.30	<u>≥</u> 250 x 10 ⁶ Btu. Doesn't indicate fuel.
Virginia			0.70	0.30	> 250 x 10 ⁶ Btu
Washington					NSPS do <u>not</u> apply
West Virginia					
Wisconsin			0.70	0.30	> 250 x 10 ⁶ Btu
Wyoming	0.75		0.70		
		0.46			<u>≥</u> 250 x 10 ⁶ Btu
		0.60			< 250 x 10 ⁶ Btu
				0.30	<u>≥</u> 1.0 x 10 ⁶ Btu
				0.60	< 1.0 x 10 ⁶ Btu

TABLE 1.39. State NO_x Regulations As They Apply To New Fuel Combustion Sources³³

Minimum Size Requirement (Heat Input) 10 ⁶ Btu	Maximum Emissions from Solid Fuel (lbs/10 ⁶ Btu)				Maximum Emissions from Liquid Fuel (lbs/10 ⁶ Btu)			
	< .70	.70	> .70	Total No. of States	< .30	.30	> .30	Total No. of States
None	-	2	-	2	-	2	-	2
≥ 1.0	-	-	-	-	-	2	-	2
> 5.0	-	1	-	1	-	1	-	1
≥ 50	-	1	-	1	-	1	-	1
≥ 100	-	1	-	1	-	1	1	1
≥ 250	1	19	3	23	-	23	1	24
TOTAL				28				31

NOTES: Not all states have regulations restricting NO_x emissions. In a few cases, regulations apply to liquid fuel only.

Washington does not have state regulations and also explicitly states that NSPS does not apply.

- *Carbon Monoxide Emission Limitations.* Carbon monoxide, as in the case of hydrocarbons, mainly regulate internal combustion engines. Sixty-three percent of U.S. CO emissions are from transportation sources. Stationary source fuel combustion contributes only 2% and incineration 8% of total national emissions.

The federal government has imposed a primary national ambient air quality standard of $10 \mu\text{g}/\text{m}^3$ over eight hours and $40 \mu\text{g}/\text{m}^3$ over a one hour period. In response to these standards, states have regulated vehicular sources rather than stationary sources. ICES developments are not likely to be effected by state CO regulations with the possible exception of emission limitations on IC engines. New source review of ICES designs is not expected to present regulatory constraints to the energy system.

- *Aldehyde Emission Limitations.* Aldehyde emissions, like hydrocarbon and CO emissions, are not major pollutants associated with ICES components. Any regulatory restrictions placed on these pollutants would result from a new source review or an environmental impact statement review. In the case of such a review, restrictions are not likely on these pollutants unless a specific local problem exists prohibiting increased emissions of these pollutants. As shown earlier in this chapter, emissions of these pollutants are low for the range of ICES components. No specific federal or state legislation regulates ICES aldehyde emissions.

1.4.3 *Federal, State and Local Water Pollution Control Regulations*

The Federal Water Pollution Control Act of 1972 set into motion regulations to restore and maintain the chemical, physical and biological integrity of the nation's waters. In addition to authorizing financial assistance for water treatment works, waste management and research, the Act under Section 306 provided for National Standards of Performance. The National Pollutant Discharge Elimination System (NPDES) required the EPA administration to propose regulations which reflect the greatest degree of effluent reduction achievable through application of the best available demonstrated control technology.

The U.S. Environmental Protection Agency (USEPA) has issued effluent guidelines and standards for steam electric power generating facilities. Authority comes from Sections 301, 304, 306, 307 and 501 of the Federal Water

Pollution Control Act. Effluent guidelines do not apply to "small" or old generating facilities. "Small" facilities are defined as units less than 25 megawatts net generating capacity or part of an electric utility system with a total net generating capacity of less than 150 megawatts. Old units are greater than 500 megawatts installed before January 1, 1970 or any unit less than 500 megawatts placed in service after January 1, 1974.³⁴ ICES will be influenced by wastewater regulations only to the extent that they exceed EPA's size cutoff. Federal wastewater restrictions are subdivided into low volume wastewater discharge, ash transport water, metal cleaning wastes, boiler blowdown, cooling water discharge and cooling tower discharge.

The quantity of total suspended solids (TSS) in low volume wastewater shall not exceed 30 mg per liter of discharge. Over a 30 day period, the average discharge shall not exceed 30 mg per liter of discharge. Oil and grease are limited to 20 mg per liter with a maximum 30 day average of 15 mg per liter. Ash transport water is that used in the hydraulic transport of fly ash or bottom ash. The same standards apply as with the general wastewater discharges. Metal cleaning wastewater has the same (TSS) and oil and grease discharge limitations as other discharges but restrictions on total copper and iron of 1.0 mg per liter maximum monthly average and one day limit are also imposed. Boiler blowdown restrictions are the same as those for metal cleaning wastewater. To the extent that once through cooling is used for machinery, a free chlorine restriction of .5 mg per liter maximum concentration with an average concentration of .2 mg per liter is imposed in federal guidelines. Cooling tower blowdown is restricted in a similar manner as cooling water. General guidelines also exist restricting the pH of all discharges to 6.0-9.0 and no discharges of polychlorinated biphenyl compounds used in transformer fluid. (Appendix H elaborates on EPA discharge units.)

Wastewater discharge from ICES are regulated only to the extent that larger ICES may exceed the cutoff point for NPDES permit requirements. While NPDES permits are part of a federal discharge control program, states are delegated the authority to issue permits and enforce effluent limitations.

As previously discussed, water discharge is not likely to be a primary environmental constraint on ICES. Generally, ICES components require a greater degree of water purity than ambient water supplies can deliver. Pretreatment is almost always necessary for normal prime mover utilization. In addition to

pollutant discharge restrictions, states have enacted thermal discharge restrictions applicable to those ICES not able to recover waste heat. Table 1.40 presents maximum thermal discharge limitations.

1.4.4 Federal, State and Local Noise Regulations

Noise regulations are difficult to assess. Various agencies in the federal government have published guidelines for noise levels, many of which are contradictory. General agreement on certain federal noise criteria is beginning and hopefully a uniform set of standards will emerge. More important than federal guidelines on noise are the state and local statutes concerning noise emissions. Perhaps the greatest threat to energy development is local resistance to proposed projects. Environmental emissions and socioeconomic impacts of proposed energy impacts are of prime concern to local residences. Noise emissions, particularly, are a prime source of complaints wherever mechanical equipment is in operation. As a result, local zoning ordinances place perhaps the first line of resistance to energy development in communities. Noise zoning ordinances will be discussed in the next chapter. The second line of resistance comes from state nuisance regulations pertaining to noise.

Federal regulation controlling occupational exposure to noise is authorized in Section 50-204.10 of the Occupational Safety and Health Act (OSHA) passed by Congress in 1971. Noise criteria shown in Table 1.41 apply to interior noise generated by power generation equipment.³⁶

The U.S. Department of Housing and Development (HUD) has also established noise criteria in Circular 1390.2. This circular establishes departmental policy on acceptable noise exposure levels to be used in the approval or disapproval of all HUD projects. Table 1.42 presents general HUD guidelines for new developments.

A third set of federal noise criteria come from the Noise Control Act of 1972. This Act designates the U.S. Environmental Protection Agency (USEPA) as the coordinator for all federal noise control programs. To date, authority has been granted for noise emitted by transportation sources. Noise from power generating facilities has not been addressed although the Act does require EPA's administrator to publish reports identifying major sources of noise and to propose noise emission standards. The Department of Transportation (DOT), Federal Highway Administration has also issued a standard (DOT designation

TABLE 1.40. State Regulations for Thermal Discharge³⁵

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Minimum Size of Effluent Sources (Btu/hr)
Alabama			
	Streams, lakes, reservoirs	5°F	
	Coastal, estuaries	4°F Oct-May 1.5°F June-Sept	
Alaska			
Arizona			
Arkansas			
	Larger streams	1/4 of the cross- sectional area and/or volume of the stream flow	5°F
	Smaller streams	2/3 of the width	5°F
	Lakes, reservoirs	Defined on individual basis	3°F
Note: Temperature requirements do not apply to privately-owned reservoirs for industrial cooling.			
California	Same as Federal Water Pollution Control Act		
Colorado			
	Class A ₁ , B ₂ Water		2°F
	Class A ₂ , B ₂ Streams		5°F
	Class A ₂ , B ₂ Reservoirs		3°F
Connecticut	1/4 of the cross- sectional area and/or volume of flow		
	Class B, C - Inland Waters		4°F
	Class SA, SB, SC - Coastal, Marine Waters		4°F Oct-June 1.5°F July-Sept

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Delaware	Length - 3500 ft. or 20 times width Width - 25%		NPDES limits
Coastal, Estuarine Waters Nontidal Streams		4°F Sept-May 1.5°F June-Aug 5°F	
D.C.			
Florida	Individually established		≥1,000,000
Fresh waters, streams		5°F	
Fresh waters, lakes, reser- voirs		3°F	
Coastal waters		2°F June-Sept 4°F Oct-May	
Open waters		17°F	
Georgia	"Reasonable and limited"	5°F	
Estuarine waters		1.5°F	
Trout, smallmouth bass waters		0	
Hawaii	Best degree of control	1.5°F	NPDES limit
Idaho			
From single source		0.5°F	
From all sources		2°F	
Illinois	Radius of 600 ft.	5°F	0.5 billion
Indiana	1/4 of the cross-sectional area and/or volume of the flow		NPDES limit
Streams		5°F	
Lakes, reser- voirs		3°F	
Trout, salmon lakes		0	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Iowa	1/4 of the cross-sectional area or volume of flow		
	Interior streams	5°F (2°F/hr)	
	"Cold water fisheries"	3°F (2°F/hr)	
	Lakes, reservoirs	3°F (2°F/hr)	
	Missouri, Mississippi Rivers	5°F (2°F/hr)	
Kansas	1/4 of the cross-sectional area and/or volume of flow		
	Streams	5°F	
	Lakes	3°F	
Kentucky			
	Public water impoundments	3°F	
Louisiana	1/4 of the cross-sectional area and/or volume of flow		
	Fresh water, streams, rivers	5°F	
	Fresh water, lakes, reservoirs	3°F	
	Estuarine, coastal waters	4°F Oct-May 1.5°F June-Sept	

Note: Temperature requirements do not apply to reservoirs constructed solely for industrial cooling.

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Maine	Zone of passage must be at least 3/4 of the cross-sectional area at any point		
	Freshwater body	5°F	
	Lake, pond	3°F	
	Tidal water	4°F 1.5°F June-Sept	
Maryland	Individually established		
	Class I waters	5°F	
	Class II waters	1.5°F June-Aug 4°F Sept-May	
Massachusetts	Zone of passage must be provided		
	Freshwater	4°F	
	Saltwater	0	
Michigan	25% of the cross- sectional area or volume of flow		
	Lake Michigan Radius of 1000 ft.		
	Great Lakes, connecting waterways	3°F	
	Inland lakes	3°F	
	Impoundments, rivers, streams supporting cold- water fish	2°F	
	Impoundments, rivers, streams supporting warm- water fish	5°F	
Minnesota	25% of the cross- sectional area and/ or volume of flow		NPDES limit
	Streams	5°F	
	Lakes	3°F	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Mississippi	Defined on case-by-case basis		NPDES limit
	Streams, lakes, reservoirs	5°F	
	Coastal, estuarine waters	4°F Oct-May 1.5°F June-Sept	
Missouri			NPDES limit
Montana			NPDES limit
	32°-66°F	1°F	
	>66°F	0.5°F	
Nebraska	1/4 of the cross-sectional area and/or volume of flow		NPDES limit
	Receiving water	5°F (2°F/hr)	
	Missouri River	4°F	
	Trout Waters	5°F	
	Impoundments	3°F	
Nevada	Individual standards assigned to all control points		
New Hampshire			
New Jersey	1/4 of the cross-sectional area and/or volume of the stream		
	Trout production waters	1°F	
	Trout maintenance streams	2°F	
	Non-trout fresh water streams	5°F	
	Non-trout fresh water lakes	3°F	
	Tidal waters, Atlantic Ocean	4°F Sept-May 1.5°F June-Aug	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
New Mexico	1/4 of the cross-sectional area of the stream or reservoir		
Streams		5°F	
Lakes, reservoirs		3°F	
New York	Individually defined		NPDES limit
Non-trout streams		5°F	
Trout streams		2°F June-Sept 5°F Oct-May	
Lakes		3°F	
Coastal waters, estuaries		4°F Oct-June 1.5°F July-Sept	
North Carolina	Defined on case-by case basis		NPDES limit
Fresh waters		5°F	
Salt waters		4°F Sept-May 1.5°F June-Aug	
North Dakota	25% of the cross-sectional area or volume of flow	5°F	NPDES limit
Ohio	1/2 the width of the receiving watercourse; 1/3 of the area of the cross-section of the watercourse; extend downstream 5 times the watercourse width; exceed 12 acres of horizontal area (23 acres of Ohio River)	15°F May-Oct 23°F Nov-Apr (in mixing zones)	NPDES limit
Cold water fisheries	1/3 the width of the receiving watercourse; 1/5 the area of the cross-section of the watercourse; exceed 3 acres of horizontal area	5°F May-Oct (in mixing zones)	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Ohio (Contd.)			
Lake, reser- voir	300 ft. from pt. of discharge	15°F May-Oct 23°F Nov-Apr (in mixing zones)	
Lakes, reser- voirs		3°F	
Streams		5°F	
Lake Erie		3°F	
Oklahoma			
Oregon	Individually defined		NPDES limit
Single source		0.5°F	
All sources		2°F	
Pennsylvania	Individually determined	5°F (2°F/hr)	NPDES limit
Puerto Rico			
Rhode Island	1/4 of the cross-sectional area and/or volume of flow		
Fresh water		4°F	
Sea water		4°F Oct-June 1.5°F July-Sept	
South Carolina	25% of the cross-sectional area and/or volume of the flow		
Specified streams		5°F	
Fresh waters		5°F	
Tidal waters		4°F Fall, winter, spring 1.5°F Summer	
Lakes, reser- voirs	Individually determined	3°F	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
South Dakota	75% of the cross-sectional area of a stream; 75% of the width of the stream or 100 yds; dimensions parallel to flow no more than 1/2 mi		
	Cold water streams	4°F (2°F/hr)	
	Warm water streams	5°F (2°F/hr)	
	Lakes, impoundments for fish propagation	3°F (2°F/hr)	
Tennessee	Individually defined	3°C (2°C/hr)	
Texas	25% of the cross-sectional area and/or volume of flow		
	Fresh water streams	5°F	
	Fresh water impoundments	3°F	
	Tidday, Bay, Gulf waters	4°F Fall, winter, spring 1.5°F Summer	
Note: Temperature requirements do not apply to offstream or privately owned reservoirs constructed for industrial cooling.			
Utah			
	Class CC waters	2°F	
	Class CW waters	4°F	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Vermont	25% of the cross-sectional area and/or volume		NPDES limit
	Streams, rivers	1°F	
	Streams, rivers with warm water species +66°F	1°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	
	63°-66°F	2°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	
	59°-62°F	3°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	
	55°-53°F	4°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	
	-55°F	5°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	
	Lakes, ponds, reservoirs supporting trout, salmon, etc.	1°F	
	Other lakes, ponds, reservoirs +60°F	1°F (0.5°F/hr, May-Oct; 1.0 F/hr, Nov-Apr)	
	50°-60°F	2°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	
	-50°F	3°F (0.5°F/hr, May-Oct; 1.0°F/hr, Nov-Apr)	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Virginia	Case-by-case basis		NPDES limit
Lakes, impound- ments		3°F	
Ocean, estuarine waters		4°F (Sept-May; 2°F/hr) 1.5°F (June-Aug; 2°F/hr)	
Free-flowing streams		5°F (2°F/hr)	
Washington		0.5°F to specified temperatures	NPDES limit
West Virginia		5°F	
Warm-water streams	50% of the width of receiving stream; 35% of the cross- sectional area; 10 times average width; horizontal area of 23 acres in Ohio River or 12 acres in other streams		
Cold-water streams	33% of width of stream; 20% of the cross-sectional area; 5 times average width; hori- zontal area of 3 acres		
Lakes	300 ft. from pt. of discharge		
Trout streams		5°F	
Trout lakes, reservoirs		3°F	
Wisconsin	25% of the cross- sectional area or volume of flow; 50% of width		
Lakes Michigan, Superior		3°F	
Shoreline	Rectangle extending 1250 ft. along shoreline and 1250 ft. into lake		
Offshore	100 ft. radius circle		
Streams		5°F	
Lakes		3°F	

TABLE 1.40. State Regulations for Thermal Discharge (Contd.)

State	Mixing Zone (Maximum Size)	Maximum Temperature Rise	Effluent Sources (Btu/hr)
Wyoming	Individually defined		NPDES limit
	Streams $\leq 68^{\circ}\text{F}$	2°F	
	Streams $> 68^{\circ}\text{F}$		
	Warm-water fisheries	4°F	
	Cold-water fisheries	2°F	
	Impoundments	2°F	

TABLE 1.41. OSHA Permissible Noise Exposure
Interior Powerplant Noise³⁶

Duration Per Day (hrs)	Sound Level, dBA (slow response)
8	90
6	92
4	95
3	97
2	100
1 1/2	102
1	105
1/2	110
1/4 (or less)	115

NOTE: Exposure to impulsive or impact noise should not exceed 140 dB peak sound pressure level. Levels measured on A-scale.

TABLE 1.42. External and Interior Noise Exposure Standards
Department of Housing and Urban Development³⁷

General External Exposures	Assessment
Exceeds 80 dBA 60 minutes per 24 hours	Unacceptable Exceptions are strongly discouraged and require a 102(2) C environmental statement and the Secretary's approval
Exceeds 75 dBA 8 hours per 24 hours	
Exceeds 65 dBA 8 hours per 24 hours	Discretionary - Normally unacceptable
Loud repetitive sounds on site	Approvals require noise attenuation measures, the Regional Administrator's concurrence, and a 102(2) C environmental statement
Does not exceed 65 dBA more than 8 hours per 24 hours	Discretionary - Normally acceptable
Does not exceed 45 dBA more than 30 minutes per 24 hours	Acceptable

NOTE: Interior noise levels should not exceed the following in sleeping quarters:

- 55 dBA for more than 60 minutes per 24 hours
- 45 dBA for more than 30 minutes from 11 p.m. to 7 a.m.
- 45 dBA for more than 8 hours per 24 hours.

ppm 90-2) for acceptable noise levels adjacent highways. As in the case of EPA transportation noise guidelines, DOT regulations will not directly impact ICES energy system design, although recommended noise levels for residential units are presented by the agency.

The General Services Administration is the remaining agency which subjects any construction equipment used on government contracts to specific noise limitations. Limits presented in Table 1.43 are not to be exceeded at a distance of 50 feet from construction activity.

In addition to federal legislation governing government funded or sponsored projects and occupational safety criteria, almost every state has some sort of noise limitations in the form of nuisance, zoning, building, vehicle or aircraft noise regulation. Table 1.44 presents example state noise regulations for land use. Table 1.45 presents criteria for commercial land use. Colorado, Illinois, New Jersey and Oregon are the first to pass statewide legislation restricting land use by noise emissions.

By far the most comprehensive set of regulatory constraints imposed on ICES are associated with local zoning ordinances. Local zoning constraints are most likely to limit emissions from power generating machinery. Table 1.46 presents a typical zoning noise ordinance. Table 1.47 presents ASHRAE guidelines similar to most zoning criteria. Zoning ordinances are discussed in more detail in Chapter 2. These zoning ordinances are sometimes supplemented by general local noise ordinances. Table 1.48 presents illustrative local intrusive noise limitations.

1.4.5 Other Environmental Regulatory Constraints on ICES Operation and Design.

Internal combustion engines are likely to be restricted by statutes aimed at vehicular sources. The Federal Environmental Protection Agency announced standards on heavy duty truck engines for carbon monoxide and hydrocarbons plus nitrogen dioxide. Seven states have enacted some sort of IC engine regulation. Minnesota has passed regulations directly restricting operation of stationary internal combustion engines. Table 1.49 presents current state laws governing the use of IC engines.

TABLE 1.43. Construction Noise Requirements:
General Services Administration³⁸

Equipment	Effective 1/1/75
Earthmoving	dB(A)
front loader	75
backhoes	75
dozers	75
tractors	75
scrapers	80
graders	75
truck	75
paver	80
Materials Handling	
concrete mixer	75
concrete pump	75
crane	75
derrick	75
Stationary	
pumps	75
generators	75
compressors	75
Impact	
pile drivers	95
jack hammers	75
rock drills	80
pneumatic tools	80
Other	
saws	75
vibrator	75

TABLE 1.44. State Noise Regulations for Residential Land Use³⁹

State	Maximum Continuous Noise		Maximum Impulse Noise		Comments
	Ld	Ln	Day	Night	
Colorado	55	50			Exempts aircraft
Illinois	55	45	50	45	From residential sources
	55	45		50	From commercial sources
	61	51		57	From industrial sources
New Jersey	65	55	80		Effective 1/18/74
		50	80		Effective 1/1/76
Oregon	60	55			All private property

Source: *Noise Source Regulation in State and Local Noise Ordinances*,
USEPA, February 1975, EPA 550/9-75-020.

TABLE 1.45. State Noise Regulations for Commercial Land Use³⁹

State	Maximum Continuous Noise		Maximum Noise Level	Maximum Impulse Noise		Comment
	Ld	Ln	L Max	Day	Night	
Colorado	60	55				Exempts aircraft
Illinois	55	Not specified		50	45	From residential sources
	61	Not specified			57	From commercial sources
	66	Not specified			57	From industrial sources
New Jersey			65		80	

Source: *Noise Source Regulation in State and Local Noise Ordinances*,
USEPA, February 1975, EPA 550/9-75-020.

TABLE 1.46. Limited Industrial District Nonperformance Standards
for Will County, Illinois⁴¹

Octave Band Pre-1960 (Cycles Per Second)	<u>Maximum Permitted Sound Levels</u>	
	Decibels (Re .0002 Microbar) Neighboring Lot	Residence District
20 - 75	79	72
75 - 150	74	67
150 - 300	66	59
300 - 600	59	52
600 - 1200	53	46
1200 - 2400	47	40
2400 - 4800	41	34
Above - 4800	39	32

Octave Band Preferred Frequencies (Cycles Per Second)	Neighboring Lot	Residence District
31.5	83	76
63	78	71
125	72	65
250	64	57
500	57	50
1000	51	45
2000	46	39
4000	41	34
8000	38	32

Impact noises measured on an impact noise analyzer shall not exceed the following peak intensities:

	Neighboring Lot	Residence District
Overall Peak	86	80

TABLE 1.47. Noise Criteria (In Decibels) for Typical Areas⁴²

Octave Bands in Cycles Per Second	37.5- 75	75- 150	150- 300	300- 600	600- 1,200	1,200- 2,400	2,400- 4,800	4,800 10,000
Highly Critical Hospital or Residential Zone	70	49	38	35	34	33	33	33
Night, Residential	72	57	47	40	38	38	38	38
Day, Residential	75	62	52	45	43	43	43	43
Commercial	78	68	60	55	51	47	44	43
Industrial-Commercial	78	73	65	60	58	57	54	54
Industrial	85	82	76	72	70	68	66	66
Ear Damage Risk	110	102	96	94	94	94	94	94

TABLE 1.48. Local Jurisdiction Intrusive Noise Source Regulations⁴³

State Jurisdiction	<u>Mechanical Equipment</u>		<u>Electronic Equipment</u>		Comments
	Max. Level	Meas. Dist.	Max. Level	Meas. Dist.	
<u>California</u>					
Burbank	50 60 70 75				Residential - 10 pm - 7 am Residential - 7 am - 10 pm Commercial All other
Downey			<5	P/L	Above ambient; outdoor
Inglewood	<5	P/L			Above ambient
San Diego			<90	50 ft.	10 sec. duration/10 min.; outdoor
Torrance	<5	P/L	<5	P/L	Above ambient
<u>Florida</u>					
Broward Co.			80 75	25 ft. 25 ft.	Industrial area; outdoor Business/Commercial Prohibited Residential
Coral Gables	<60	15 ft.			Or 15 ft. from P/L
Hollywood	<60	P/L or 15 ft.			Whichever is greater
<u>Illinois</u>					
Marengo	<5 <5 dB		<15	P/L	Above ambient Any Octave Band re Amb.
<u>Indiana</u>					
Indianapolis			<100 dBC		
<u>New York</u>					
New York City	45	3 ft.			Inside nearest open window of dwelling affected
<u>Wisconsin</u>					
Milwaukee	60.5				Specified in octave bands; violation if >5 dB any band
Racine			<5		Above ambient in any adjacent dwelling

Source: *Noise Source Regulation in State and Local Noise Ordinances*,
USEPA, Feb. 1975, EPA 550/9-75-020

TABLE 1.49. Emission Regulations for Gasoline and Diesel Powered Vehicles⁴⁴

California - 1973 and 1974 Model Year standards for heavy-duty gas and diesel powered vehicles:

HC and NO₂ - 16 g/Bhp-hr

CO - 40 g/Bhp-hr

District of Columbia - Diesel fuel standards for Diesel #1 fuel:

Carbon Residue (10% bottom) - 5% Max.

Sulphur - 20% Max.

Ash Content - 1% Max.

Minnesota -

Stationary internal combustion engines in Minneapolis - St. Paul AQCR or with heat input

>250 x 10⁶ BTU: SO₂ - 1.75 lb/10⁶ BTU

Nevada - Light duty gas-fueled motor vehicles:

<u>Model Year of Vehicle</u>	<u>CO%</u>	<u>HC (ppm)</u>
Up to and including 1967	7.5	1200
1968 - 1969	5.0	600
1970	4.0	400
1971 and later	4.0	400

New Jersey - Light-duty gas-fueled motor vehicles:

<u>Model Year of Vehicle</u>	<u>CO%</u>	<u>HC (ppm)</u>
Up to and including 1967	7.5	1200
1968 - 1969	5.0	600
1970 - 1974	4.0	400
1975 - 1976	2.0	200
1977 and later	To be Promulgated	

New York - Light-duty gasoline motor vehicles:

<u>Model Year of Vehicle</u>	<u>Phase I</u>		<u>Phase II</u>		<u>Phase III</u>	
	(effective immediately)		(effective 5-1-78)		(effective 5-1-79)	
	<u>CO(%)</u>	<u>HC(ppm)</u>	<u>CO(%)</u>	<u>HC(ppm)</u>	<u>CO(%)</u>	<u>HC(ppm)</u>
pre-1968	10.0	1600	8.5	1400	7.5	1200
1968 - 1969	8.0	800	7.0	700	6.0	600
1970 - 1974	6.0	600	5.0	500	4.0	400
1975 and later	3.0	300	2.0	200	To be Promulgated	

Heavy-duty gasoline motor vehicles:

<u>Model Year of Vehicle</u>	<u>Idle</u>		<u>High Cruise</u>
	<u>CO(%)</u>	<u>HC(ppm)</u>	<u>CO(%)</u>
1970 and earlier	4	700	1.5
1971 and later	2	100	1.5

Oregon - has CO and HC idle emission standards for light-duty motor vehicles, but not listed in regulations.

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2 IMPACT OF SITING AND ZONING REGULATION ON ICES APPLICATION

2.1 INTRODUCTION AND OVERVIEW

The spectrum of siting regulations influencing community energy systems spans general federal legislation restricting uncontrolled energy developments to local zoning ordinances often regulating land use, lot size and building design. Between federal and local regulation is the emergence of state siting commissions whose objective is to review and, if necessary, regulate the development of new energy systems. The purpose of this chapter is to summarize siting law likely to influence ICES development.

- *Federal Legislation.* Three categories of siting law govern power plant location: federal, state and local restrictions. Federal legislation has addressed siting indirectly vis-a-vis two pieces of legislation -- The National Environmental Policy Act (NEPA) and the Coastal Zone Management Act. NEPA, as discussed in Chapter 1, requires Environmental Impact Statements prior to commencement of any federal or federally involved project. This includes projects using federal land or money. All Department of Housing and Urban Development projects, for example, require an Environmental Impact Statement. In the EIS, siting alternatives and associated environmental impacts must be considered. The final EIS must be approved by the Environmental Protection Agency after appropriate public hearings have been completed. NEPA is perhaps the most significant federal statute impacting location of a proposed ICES. It, in effect, requires that the project meet all federal, state and local regulations. Failure to complete an acceptable EIS can result in a court injunction barring any construction activity.

The Coastal Zone Management Act (CZMA) of 1972 is the other piece of federal legislation with a potential impact on ICES development. Amendments to the CZMA in 1976 expanded the scope of the Act and provided for increased planning and management of energy facilities affecting coastal zones. The objective of the Coastal Zone Management Act is to assist coastal states in establishing programs for preserving their coastal resources. Coastal states include the eight Great Lake states as well as eastern, western, and Gulf coastal states. The CZMA provides funds to states and outlines criteria for state planning agencies. While states may not arbitrarily exclude energy facilities from coastal zones, they may restrict or curtail development in certain coastal areas. The Coastal Zone Management Act may require in ICES developers to work with state

coastal zone planning agencies when siting involves shoreline development. Other than certain specific cases, CZMA is not likely to greatly promote or inhibit ICES development.

- *State Regulation.* An increasing number of states are utilizing state Environmental Impact Statements to cull undesirable projects. The state EIS is a direct counterpart to federal EIS. Two basic differences exist in state impact statements. First, the EIS is circulated among state and local agencies for review and acceptance. Second, the state EIS may be required for private and public projects and is often the initial step in obtaining state permits and licenses. Five states have adopted statewide EIS programs regulating public and private facilities. State EIS requirements, as in the case of federal statements, require a demonstration of environmental acceptability and compliance with local law. The state EIS program allows for public input before approval is granted.

In addition to EIS, 25 states have established specific regulations governing the siting of power facilities. In most cases, state laws govern construction of power plants and transmission lines. State siting laws often require certification of power plant sites and transmission corridors, and a general project review. Of the 25 states with siting legislation, 20 have a 100 MW cutoff. Connecticut, Delaware, Florida, Kentucky, Maryland, Nevada, and New Jersey have no cutoffs. ICES would be required to obtain state certification and licenses prior to construction. Appendix C provides a listing of states having siting laws regulating power facilities. The prime impediments created by federal and state impact statements, state siting regulations and licensing requirements, are the time and resources required to obtain necessary approvals. Projects may be delayed several years waiting for EIS and license approval. Impact statements could add several hundred thousand dollars to project costs adding a one year delay to project commencement. States are becoming sensitive to time delays associated with project approval and are instituting policies designed to shorten approval time. Many states have instituted a "one stop licensing" process where all state permit decisions are made.

To this point, discussion of federal and state regulations has been limited specifically to direct siting regulation. Forty-seven states also exert the authority to certify and regulate public and private utilities through state utility commissions. These commissions have the authority to regulate

service, construction and abandonment of utility facilities including electric, gas, and telephone. Appendix D presents states requiring certificates of convenience and necessity. Also indicated are those states which have included environmental analysis as part of the commission's authority.

- *Local Siting Law.* Considering all federal and state legislation regulating power facilities, regulations most influencing ICES development and design are local zoning laws. Virtually every county and municipality in the country has some sort of siting regulation. Zoning laws dictate land use, establish performance standards and reflect the local opinion of any new project.

2.1.1 Local Siting Impediments to ICES Development

Unfortunately, traditional zoning regulation is intended to achieve land use goals in ways not supportive of or compatible with current efforts towards community energy conservation. Restrictive zoning regulations do not facilitate the development of Integrated Community Energy Systems. Developers are likely to face two broad problem areas:

- Zoning can limit the use of community forms that are energy conservative, in part, because of higher residential energy demand densities, the use of building/site arrangements that reduce space conditioning requirements and automobile use, and efficiencies arising from a mutually supportive mix of different land uses.
- Zoning can restrict the actual siting of ICES components within a community, many of which are considered heavy industrial land uses.

It is not surprising that many zoning regulations hamper, rather than encourage, efforts to conserve energy considering that zoning is a legal tool used to implement policies embodied in local land use plans that, as yet, rarely consider land use/energy relationships. Failures of local governments to significantly integrate land-use and energy-use policies can be traced to public apathy toward energy conservation combined with a widespread lack of regional, state, and federal level guidance.⁷ Much of this inaction appears to result from a rather poor understanding of exactly how the pursuit of energy goals is to be reconciled with attempts to achieve possibly overriding local economic, social, and environmental goals.

In the absence of large-scale efforts aimed at changing fundamental land use/energy policies and practices, a number of conventional zoning procedures and control innovations are available to promote community energy conservation, in general, and aid ICES application, in particular.

Often it seems that amendments to the zoning ordinance or special-use permits may be required to site community energy system components in nonindustrial districts. In these circumstances, ICES technology will almost certainly be subjected to stringent tests of environmental acceptability, and the benefits of community energy systems over conventional utility servicing will have to be demonstrated conclusively.

Applications of energy-conservative community designs that are restricted by conventional zoning regulation often are permitted under Planned Unit Development (PUD) procedures. PUDs are developments ranging in size from small residential projects to entire new communities, designed and regulated as a unit rather than by the traditional single building/lot basis. A high degree of administrative discretion is left to zoning authorities, and developers have considerably more building and site design flexibility. In many cases, PUDs allow increased residential densities, clustered housing in conjunction with innovative street design, and the mixing of residential, commercial, and industrial land uses in districts where conventional regulations ordinarily bar these energy conserving land development techniques. PUDs may be one way to implement energy efficient communities without substantially changing existing law.

Portions of this report are intended to provide nonplanners with background information concerning the nature of traditional zoning regulation and the more recent land use control innovations that may aid community energy systems' development. Much of the previously reported information⁷ describing potential zoning constraints on ICES application served to direct a case study review (presented in Sec. 2.2) of several county, municipal, and model zoning ordinances. The examination of actual zoning ordinances was used to characterize, more explicitly, the extent of zoning problems likely to be encountered in ICES commercialization efforts. From both the generic analysis⁷ and the zoning ordinance review, more specific zoning/ICES issues could be addressed, and these considerations are included in Sec. 2.3. There are several near-term avenues of relief that developers may be able to exploit in attempts to

circumvent zoning regulations that unintentionally inhibit community energy conservation. These "solutions," which include both traditional and innovative zoning procedures designed to provide regulatory flexibility, are discussed in Sec. 2.4.

2.1.2 Definition, Purpose and Authority for Local Siting Regulation

Zoning is a means of ensuring that each activity of a community receives adequate amounts of land in a location suitable to its needs, and in such a manner that adjacent land uses are compatible. Zoning is one of a number of legal devices (including subdivision regulations, building codes, etc.) used to implement a land use plan containing guidelines for the future development or redevelopment of an area. In addition to itemizing the permitted land uses within certain specified "zones" or "districts," zoning regulations control the height and bulk of buildings and other structures, the size of open spaces that must be provided around them, and the intensity with which land may be developed.¹⁴

Zoning power, as an adjunct of general police powers, is granted by states to counties and municipalities through enabling legislation often modeled on the Standard Zoning Enabling Act (1924).¹⁷ All states have an enabling act authorizing municipal zoning and well over half the states have authorized some or all of their counties to zone.¹² County zoning authority usually covers all unincorporated land and, in some states, those incorporated areas that have not adopted separate zoning ordinances. In some cases, special planning regions may be created, that may be composed of a portion of a single county or parts or all of several counties. Regional zoning regulations then may be adopted voluntarily by the governmental units affected.⁶

2.1.3 Structure of Zoning Regulation

Zoning ordinances define a number of districts or categories of land use (typically residential, commercial, and industrial), which are used to classify all land within the political jurisdiction of a given authority. For each district, certain uses are permitted, and explicit restrictions on building, height, and bulk layout are presented so that individualized administrative treatment is not required. Within each district, regulations must be uniform, but regulations in one district may differ from those in other districts.¹²

District use regulations may be of either a permissive or prohibitive nature. Permissive regulations are presented in the form of "use lists" that enumerate the types of residential dwellings, businesses, or industries that may be sited within a certain zone. All other uses are excluded from the district unless some form of special approval can be obtained from zoning authorities. In the prohibitive form commonly used to control development in industrial areas, any use is allowed unless explicitly banned. Land uses, especially residential and industrial, continue to be segregated:

- because the mixing of "incompatible" uses could have adverse effects on each other and depreciate property values and desirable environmental features, and
- to ensure that uses requiring extensive public service facilities (schools, streets, utilities) are restricted to areas where they already exist or are expected to be installed.⁶

The typical zoning ordinance establishes at least one single family residence district, a series of multiple family districts, several business/commercial districts, and possibly several industrial districts.

● *Residential Districts.* In general purpose communities, residential properties often are the most numerous, and occupy the largest and most choice land areas.³ Although zoning ordinances vary widely in detail, allocation of land for residential uses in most communities is similar. Usually, a single-family residence district is established, in which minimum lot size is large and, hence, dwelling unit density low. A second district may allow both single and two family dwellings, while a third may permit apartments. Commercial uses, to provide the daily needs of residents, are sometimes permitted under special use provisions, however, industrial uses (e.g., power plants, incinerators) rarely are allowed.

● *Commercial Districts.* Commercial districts can be classified according to the kinds of business permitted or the nature of merchandising undertaken.³ Districts may be created for particular uses (e.g., package liquor district, automotive service district), or for grouping diverse uses into areas designed to service different clientele.¹⁴ Current zoning trends employ locational criteria to group commercial uses into separate districts. For example, major commercial centers are located near transportation nodes, heavy commercial uses (e.g., building supplies, gas stations) sited along major arterials, and local convenience shopping placed near residences.

Residential uses, if allowed in commercial zones, are most often restricted to apartments. Industrial uses, except for certain types of light manufacturing (e.g., bakeries, shoe repair, etc.), typically are excluded.

● *Industrial Districts.* Industrial uses are commonly grouped into light, medium, or heavy classes by the type of process involved or the end product produced. In a rough way, then, industrial uses are classified by their requirements for special servicing (utilities, heavier roadbeds, access to rail lines and water, etc.), and their potential for nuisance to the surrounding area.³ Use lists generally are cumulative across industrial zones, that is, light industrial uses are permitted in intermediate industrial districts, and both light and intermediate uses are allowed in heavy industrial districts.

Nuisances often are controlled by the requirement that industries conform to performance standards which decrease in strictness from the light to heavy industrial districts. The environmental effects commonly considered in zoning performance standards are noise, vibration, air pollution, radioactive radiation, glare, and fire and explosion hazards. Effects less frequently regulated include heat, humidity, liquid waste, solid waste, and electromagnetic radiation.¹³ From preliminary technical assessments, it appears that the zoning performance standards of most concern to Integrated Community Energy Systems will be those controlling air and noise pollution, and fire and explosion hazards, primarily concerning fuel storage.¹⁰

With this structure, traditional zoning ordinances often are characterized as "self executing," requiring administrative discretion only in relatively few circumstances, thus speeding administration and reducing the potential for political influence of regulation.

2.1.4 Zoning Administration

The governmental organizations and administrative procedures involved in zoning vary from state to state because of differences in zoning enabling legislation. In this discussion, the descriptions of particular features of zoning administration are drawn primarily from those employed in Illinois.¹⁴

In Illinois, local land use is regulated by a Board of Zoning Appeals and a Zoning Administrator who are appointed by the local governing body, which may be the municipality's City Council or county's Board of Supervisors. The Zoning Administrator has the responsibility for the day-to-day enforcement of ordinance regulations. It is the function of the Board of Appeals to interpret provisions of the zoning ordinance, to recommend or grant variations from its requirements, and to review appeals taken from the decisions of the Zoning Administrator. The zoning ordinance or zoning district map may be amended through action by the governing body, but there must be a public hearing before the local Planning Commission or Board of Appeals. There are identical hearing procedures for approval of special use permits. The Planning Commission's function is to review broader policies of general land development as they relate to zoning and other matters, and to review proposed amendments or special use requests.

Many governmental organizations that affect zoning (e.g., planning commissions, city councils, boards of appeals) are lay bodies, and the structure of traditional zoning regulation accommodates this by being relatively explicit in specifying alternative courses of action and the circumstances in which such actions may be taken. The rigidity of conventional zoning (and subdivision) regulations, however, creates a substantial barrier to the practice of innovative land development and, unfortunately, Integrated Community Energy Systems are one such example. As land development techniques, market conditions, and technology change, the administration of land use controls becomes increasingly complex. Newer zoning techniques, designed to increase regulatory flexibility, require more frequent use of discretion by zoning authorities. Flexible land use controls may allow the implementation of ICES in situations where their use otherwise would be impossible. However, flexible zoning techniques impose high administrative and developer costs and thus, from a commercialization standpoint, reliance on these procedures carries mixed benefits.

2.2 ZONING ORDINANCE CASE STUDIES

A preliminary examination of zoning ordinances revealed that geographic location within the country was not as important as the relative intensity of a region's development in determining the nature of regulation that its counties and municipalities use to control land use. Political units within a metropolitan region generally were found to have more detailed and sophisticated zoning regulations than those of a rural community. This is due, in part, to:

- their need for more comprehensive land use control because of existing high land use intensities and planned continued development, and
- the higher probability of having well-established planning programs, sometimes coordinated on a regional level.

2.2.1 Case Study Methodology

To examine the possible impacts of existing zoning regulations and procedures on ICES implementation, zoning ordinances covering a range of local development intensities were selected arbitrarily for examination by:

- SMSA membership,
- County or municipality, and
- Municipal population size distinctions.

Zoning ordinances of the ten counties and municipalities listed in Table 2.1, as well as three model zoning ordinances, recently drafted by regional or county planning agencies to aid local planning agencies, were reviewed to determine:

- (1) the types of land uses allowed in each zoning district,
- (2) the presence of provisions designed to facilitate common-site, multibuilding development,
- (3) the types of ICES components permitted in each zoning district, and
- (4) the presence of district-specific performance standards.

TABLE 2.1. Zoning Ordinances Selected for Review

Zoning Authority	Population (1970)	SMSA
COUNTIES		
Luzerne Co., Pa.	342,329	Wilkes-Barre-Hazelton
Will Co., Ill.	247,825	Chicago
Columbia Co., Pa.	55,114	*
MUNICIPALITIES		
Chicago, Ill.	3,369,357	Chicago
Bethlehem, Pa.	72,686	Allentown-Bethlehem-Easton
Danville, Ill.	42,570	*
Bloomington, Ill.	39,920	Bloomington-Normal
Lebanon, Pa.	28,570	*
Fairfax, Va.	21,970	Washington
Effingham, Ill.	9,458	*
MODEL ORDINANCES		
Escambia-Santa Rosa Cos., Fla.	-	Pensacola
Genesee Co., Mich.	-	Flint
Marion Co., Ind.	-	Indianapolis

* NonSMSA

(1) District Use Lists: The use lists of each district present the land use types that developers can integrate within a single community. Use lists were summarized according to the following five classifications:

- *Single Family* detached dwellings,
- *Two Family* attached dwellings (e.g., townhouses and garden apartments),
- *Apartments* for multifamily use (low-, medium-, and high-rise apartments),
- *Commercial* uses, and
- *Industrial* uses.

(2) Planned Unit Development: Provisions in each ordinance for Planned Unit Development were reviewed to determine the type of PUDs allowed in each district and the administrative procedures involved. In addition, the features and requirements of special zones such as "Office and Research Park Districts" and "Planned Industrial Districts," and provisions for the clustering of dwellings in residential districts were noted.

(3) ICES Component Siting: Use and special use lists were also examined to find the general types of currently foreseen ICES technologies⁸ that would be permitted by right or through special permit procedures in each district. Because of the generality of use list entries, ICES components were aggregated into the following classes:

- *Prime Movers* (internal combustion piston engines, boilers, combustion turbines, fuel cells, etc.),
- *Gas/Liquid Fuel Production* (e.g., coal gasifiers and liquefiers),
- *Water Treatment Facilities*,
- *Reservoirs* (for potable and grey water, cooling),
- *Waste Treatment Facilities* (for sewage and industrial waste, digestors for biomethane production),
- *Incinerators* (conventional and water wall), and
- *Landfills* (conventional and sanitary).

(4) Performance Standards: Sections of the ordinances specifying industrial and commercial performance standards were reviewed for the types of nuisances regulated, the strictness of standards, and the districts in which they applied.

Tabular summaries of this information, for each zoning ordinance, are presented in Appendix E.

2.2.2 Features of the Case Study Ordinances

The 13 zoning ordinances that were examined varied widely in general detail, number of district classifications, lot and dimensional control techniques used, the standards and procedures for variations, amendments, and special uses, organizational structure of administration, and definition of terms. The number of zoning district classifications, which is a general measure of the sophistication of local regulation, ranged from the seven districts of Columbia County, Pa. (three residential, three commercial, and one industrial) to the 22 primary and 71 total districts defined in Chicago's zoning ordinance. Relative sophistication, however, does not appear to be sufficient for the relaxation of constraints to ICES implementation.

The following three sections discuss provisions in the reviewed ordinances for mixed land use development, the siting of ICES technologies, and for nuisance and hazard controls that may effect specific community energy system components.

- *Mixed Land Use Opportunities (Case Studies)*

(1) Conventional Development: Provisions for conventional, nonPlanned Unit Development of mixed residential, commercial, or industrial land uses were included in every zoning ordinance surveyed except, interestingly, the model ordinances of Genesee County, Michigan and Escambia/Santa Rosa Counties, Florida, and the highly regarded, innovative ordinance of Fairfax, Virginia.

Every zoning ordinance provided for at least one mixed density residential district. Allowance for one and two family dwelling uses in nonresidential zones, however, was not common. The more prevalent forms of mixed residential/commercial districts either permitted apartments in limited commercial zones or local convenience shopping in multifamily residential districts. Residential uses were permitted in an industrial district only in Effingham, Illinois (non-SMSA), and in this case, industrial uses were limited to those of a light manufacturing nature. All other zoning ordinances expressly prohibited dwellings in industrial districts with the exception of certain minor special uses (e.g., residences for night watchmen). Eight of the 13 ordinances allowed both commercial and industrial land uses within a single district.

Table 2.2 summarizes the nonPUD mixed land use provisions of each zoning jurisdiction by displaying the types of uses allowed and the type of district where mixed use is permitted.

(2) Planned Unit Development: Planned Unit Developments were administered as either:

- (a) a special use in only residential districts (5 cases);
- (b) a special use in all districts (3 cases);
- (c) a special use in selected residential, commercial, and industrial districts (1 case), or
- (d) a floating zone to be superimposed over certain selected districts (3 cases).

Provisions for Planned Unit Development only marginally increased opportunities for mixed land use development.

In cases where PUDs were allowed as a special use in certain specified zones, permitted land uses remained unchanged from those included on the districts' use lists, though lot, height, and bulk requirements were often eased. In fact, development under PUD regulations sometimes *decreased* the potential for mixed land use since PUDs were not allowed in districts where conventional residential/commercial or industrial/commercial development was permitted. (Refer to Tables A.6 through A.8).

In the three ordinances in which floating PUD districts had been created (i.e., Fairfax, Va.; Effingham, Il.; Marion County, Ind.), constraints to mixed land use development were considerably relaxed. Fairfax, Virginia permitted residential PUDs to include all housing types plus certain commercial facilities. Under nonPUD regulation, the mixing of one-family and apartment uses, as well as the inclusion of local convenience shopping, would not have been possible. The Special Commercial District of the Marion County model ordinance was, by far, the least restrictive in terms of mixed land use development:

The C-S special DISTRICT is designed to permit, within a single DISTRICT multiuse complexes or land use combinations of commercial and noncommercial uses, or single-use commercial projects, which due to excellence of planning, design or function, can be intermixed, grouped or otherwise uniquely located with maximum cohesiveness, attractiveness and compatibility. Thus, the DISTRICT

TABLE 2.2. NonPUD Opportunities for Single-Zone Mixed Land Use

Zoning Authority	District Type Uses Allowed*	Residential R/C	Commercial R/C C/I	Industrial C/I R/C/I
COUNTIES				
Luzerne Co., Pa.		X		X
Will Co., Ill.				X
Columbia, Co., Pa.				X
MUNICIPALITIES				
Chicago, Ill.			X	X
Bethlehem, Pa.			X	X
Danville, Ill.			X	
Bloomington, Ill.				X
Lebanon, Pa.			X	X
Fairfax, Va.				
Effingham, Ill.			X	X X
MODEL ORDINANCES				
Escambia-Santa Rosa Cos., Fla.				
Genesee Co., Mich.				
Marion Co., Ind.			X X	X

*
R: Residential
C: Commercial
I: Industrial

provides flexibility and procedural economy, by permitting the broadest range of land use choices within a single DISTRICT, with adequate land use controls. Under the C-S classification, particular regard can be given property with unique features or significance -- such as unusual topography or landscape amenities, historical, architectural or social significance, or other special land characteristics. The C-S DISTRICT can include high-rise or low-rise developments, can be applied to large or small land areas, appropriately located throughout the metropolitan area -- and can be useful in areas of urban renewal or redevelopment.

The C-S DISTRICT is intended to encourage greater creativity in land planning, superior site and structural design and development; to encourage an efficient, aesthetic and desirable use of open space; to provide for a use of land with high functional and aesthetic values; to assure compatibility of land uses, both with the C-S DISTRICT and with adjacent areas. It is intended to provide maximum flexibility in zoning districting and controls -- to meet the changing, diverse developmental needs of the metropolitan area.

Table 2.3 summarizes the land uses permitted in Planned Unit Developments for each of the reviewed zoning ordinances.

- *ICES Component Siting Potential (Case Studies)*. Many ICES components were not specifically mentioned in district use lists. In the absence of efforts to amend the zoning ordinance (Refer to Sec. 2.4.3) or to obtain special use permits (Sec. 2.4.4), and unless these technologies could be shown to be commonly associated with a permitted use, *their siting would be allowed only in unrestricted, heavy industry districts subject to performance standards*. Use restrictions of this nature will more likely be encountered in nonSMSA zoning jurisdictions where because of the general lack of ordinance detail, allowances for industrial land use are commonly phrased in the prohibitive form.

TABLE 2.3. PUD Land Uses Allowed

Zoning Authority	PUD Land Uses Allowed*						
	SF	SF,2F	SF,2F,A	SF,2F A,C	C	C,I	I R,C,I
COUNTIES							
Luzerne Co., Pa.	X	X		X			X
Will Co., Ill.	X		X		X	X	X
Columbia Co., Pa.	X		X		X	X	X
MUNICIPALITIES							
Chicago, Ill.	X		X		X	X	X
Bethlehem, Pa.			X		X		X
Danville, Ill.	X	X	X				
Bloomington, Ill.	X	X	X				
Lebanon, Pa.				NO PUD PROVISION			
Fairfax, Va.				X			
Effingham, Ill.	X	X	X	X	X	X	X
MODEL ORDINANCES							
Escambia-Santa Rosa Cos., Fla.	X	X	X				
Genesee Co., Mich.	X	X	X				
Marion Co., Ind.			X				X

- * SF: Single family detached dwellings
 2F: Two family dwellings
 A: Apartments
 R: Residential uses (all housing types)
 C: Commercial uses
 I: Industrial uses

Table 2.4 shows the number of cases (of the 13 ordinances examined) in which a potential ICES component was allowed by right or via special use permit in:

- (1) any zoning district,
- (2) any industrial district,
- (3) only medium and heavy industrial zones,
- (4) only certain residential, commercial, or industrial districts.

There was *no* case in which a prime mover ("power plant," "power house," "steam production plant"), a fuel processing plant (e.g., coal gasifier), or a large incinerator was permitted in a nonindustrial district.

Restrictions on reservoirs, and water and waste treatment plants, however, varied considerably. Some localities allowed their siting in all districts, if only under special approval, while others relegated them to heavy industrial zones.

Landfills also were commonly classified as a heavy industrial use except in a few cases in which they were permitted in rural, residential, and certain commercial districts.

● *Performance Standards (Case Studies)*. About half of the zoning ordinances contained quantitative restrictions on industrial (and sometimes commercial) air and noise emission and fuel storage. Although other nuisances and hazards (glare, vibration, odorous matter, etc.) frequently were considered, standards for these were largely qualitative, designed to provide a legal basis for action upon specific complaint. Performance standards were used in conjunction with use and prohibited use lists. No cases of pure performance zoning were encountered.

None of the nonSMSA counties or municipalities had adopted explicit industrial performance standards as part of their zoning ordinance, primarily because:

- (1) the community's zoning ordinance was relatively simple indicating that environmental regulation was deferred to a larger political unit (e.g., county, air basin commission, state), or
- (2) environmental standards for the community were uniformly applied to all districts and presented in separate ordinances.

TABLE 2.4. Number of Cases in which ICES Components are Permitted
in Selected Districts

ICES Component	Districts in which Siting is Permitted			
	All Districts	All Industrial Districts ^d	Only Medium and Heavy Industrial	Other
Prime Movers		4	9	
Gas/Liquid Fuel Prd'n		3	10	
Water Treatment	2	3	8	
Reservoirs	1	2	10	
Waste Treatment	2	1	9	1 ^a
Incinerators		1	12	
Landfills		2	8	2 ^b , 1 ^c

^a Selected commercial and industrial districts

^b Selected rural residential and industrial districts

^c Selected residential/commercial/industrial districts

^d Includes ordinances that contain only one industrial district
(i.e., Columbia, Pa.; Lebanon, Pa.; Genessee County, Mi.)

Some zoning ordinances included a catch-all, vague, and virtually unenforceable regulation, devoid of quantitative standards, e.g.:

*Regardless of any other provisions of this ordinance, no use shall be constructed or operated so as to create any noxious, offensive, objectionable, or other undesirable effect on persons or property outside the lot line by virtue of emission of smoke, particulate matter, noise, dust, fumes, vibration, odor, glare, heat, humidity, and liquid waste. Materials used and products stored shall be adequately housed, shielded, or screened so that health, safety, and welfare of persons occupying the property or adjacent properties are not jeopardized.*¹³

Table 2.5 lists those zoning jurisdictions surveyed that have included air, noise, or fuel storage performance standards within their zoning ordinances.

(1) *Air*: Smoke and particulate emissions were the most commonly controlled airborne nuisances. Smoke opacity is measured at the source and compared to values on the Ringelmann Chart, a standard method for judging the density, and hence, the offensiveness of smoke emissions. Provisions for short-term standard variances, on the order of minutes, were frequently included. Particulate matter was generally controlled on an area emission rate basis, in which standards were phrased in units of *pounds particulates per hour per lot acre*. Standards for the less commonly regulated airborne nuisances such as odors and toxic matter usually were presented in the form of a crude, lot line concentration limit, or sensing threshold criterion. In other cases, the typical performance standard was simply:

*The emission of noxious odorous matter in such quantities as to produce a public nuisance or hazard beyond lot lines is prohibited.*²¹

(2) *Noise*: Performance standards for noise typically were expressed in the form of maximum decibel levels for designated octave bands. Some ordinances included two sets of standards, one for lot line measurement, and a more restrictive set for residential district borders. Some noise standards were day/night time specific. Acceptable measurement procedures and equipment frequently were cited.

(3) *Fire and Explosion Hazards*: Many localities rely on the discretion of the local building inspector or fire department to regulate fuel storage.

TABLE 2.5. Zoning Ordinances Containing Air, Noise, or
Fuel Storage Performance Standards

Zoning Authority	Performance Standards		
	Air	Noise	Fuel Storage
COUNTIES			
Luzerne Co., Pa.*	X	X	-
Will Co., Ill.*	X	X	X
Columbia Co., Pa.	-	-	-
MUNICIPALITIES			
Chicago, Ill.*	X	X	X
Bethlehem, Pa.*	-	X	-
Danville, Ill.*	-	-	-
Bloomington, Ill.*	-	-	-
Lebanon, Pa.	-	-	-
Fairfax, Va.*	X	X	-
Effingham, Ill.	-	-	-
MODEL ORDINANCES			
Escambia-Santa Rosa Cos., Fla.*	X	X	-
Genessee Co., Mich.*	X	X	-
Marion Co., Ind.*	-	-	-

* Within SMSA

In the ordinances with specific fuel storage standards, however, fuels were categorized by their hazard potential and maximum above and underground limits were specified for each industrial district.

Table 2.6 displays the Smoke and Particulate, Noise, and Fuel Storage performance standards for the Will County, Illinois "Limited Industrial District." The organization and values of these performance standards are typical of those contained in the reviewed zoning ordinances.

2.3 ICES/ZONING PROBLEM AREAS

Restrictive provisions of traditional zoning ordinances combined with administrative inflexibility continue to impede the diffusion of innovative community design features. With regard to community energy systems, two broad areas of zoning impact are evident:

- (1) Zoning can limit the use of community forms that are energy conservative, in part, because of higher residential energy demand densities, the use of building/site arrangements that reduce space conditioning requirements and automobile use, and efficiencies arising from a mutually supportive mix of different land uses.
- (2) Zoning can restrict the actual siting of ICES components within a community, many of which are considered heavy industrial land uses.

2.3.1 Basic Issues

Examination of these problem areas can be further focused on five specific issues:

<u>ICES/Zoning Issue</u>	<u>Primary Restrictive Ordinance Feature</u>
(1) Residential density required to support a community energy system.	Minimum lot size
(2) Building-site relations in multibuilding complexes.	Yard and setback requirements
(3) Opportunities for mixed land use communities.	Use districting

TABLE 2.6. Limited Industrial District Performance Standards
Will County, Illinois

Smoke and Particulate Matter - For the purpose of grading the density or equivalent opacity of smoke, the Ringelmann Chart described in the U.S. Bureau of Mines Information Circular 8333 (May 1967) shall be employed. The emission of smoke or particulate matter of a density or equivalent opacity equal to or greater than No 2 on the Ringelmann Chart is prohibited at all times except as otherwise provided hereinafter.

Dust and other types of air pollution borne by the wind from such sources as storage areas, yards, roads, and the like within lot boundaries shall be kept to a minimum by appropriate landscaping, paving, oiling, fencing, wetting, or other acceptable means.

No operation shall cause or allow to be emitted into the open air from any process or control equipment or to pass any convenient measuring point in a breeching or stack, particulate matter in the gases that exceeds 0.10 grains per standard cubic foot (700 F. and 14.7 psia) of gases during any one hour.

Particulate matter loadings in pounds per hour per acre described below shall be determined by selecting a continuous four (4) hour period which will result in the highest average emission rate.

The emission of smoke having a density or equivalent opacity in excess of Ringelmann No. 1 is prohibited. However, for two (2) minutes in any four (4) hour period, smoke up to and including Ringelmann No. 2 shall be permitted.

The rate of emission of particulate matter from all vents and stacks within the boundaries of any lot shall not exceed 0.5 pounds per hour per acre of lot area.

Maximum Permitted Sound Levels		
Octave Band Pre-1960 (Cycles Per Second)	Decibels (Re .0002 Microbar)	
	Neighboring Lot	Residence District
20 - 75	79	72
75 - 150	74	67
150 - 300	66	59
300 - 600	59	52
600 - 1200	53	46
1200 - 2400	47	40
2400 - 4800	41	34
Above 4800	39	32

Octave Band Preferred Frequencies (Cycles Per Second)	Neighboring Lot	Residence District
31.5	83	76
63	78	71
125	72	65
250	64	57
500	57	50
1000	51	45
2000	46	39
4000	41	34
8000	38	32

Impact noises measured on an impact noise analyzer shall not exceed the following peak intensities:

	Neighboring Lot	Residence District
Overall Peak	86	80

**Total Capacity of Flammable Materials Permitted
(In Gallons)**

	Above Ground	Underground
Materials having a closed cup flash point over 187° but less than 300°F.	20,000	100,000
From and including 105°F. to and including 187°F.	10,000	100,000
Materials having a closed cup flash point of less than 105°F.	3,000	100,000
Total	33,000	300,000

When flammable gases are stored, utilized, or manufactured and measured in cubic feet, the quantity in cubic feet at standard temperature and pressure shall not exceed thirty (30) times the quantities listed above.

<u>ICES/Zoning Issue</u>	<u>Primary Restrictive Ordinance Feature</u>
(4) Siting of ICES components in nonindustrial districts.	Use districting
(5) Level of environmental control effort required for ICES application.	Performance standards

● *Residential Density.* While it is not yet clear what range of residential densities may be desirable from both a community-social and ICES-technological standpoint, in general, low density development tends to be nonenergy conservative.⁷ Detached single family housing is the least efficient user of energy both in terms of space conditioning and automotive transportation requirements. The large minimum lot size standards of traditional single family residence districts (often resulting in less than five dwelling units per acre²¹) creates developments with diffuse energy and nonenergy utility demands, requiring more extensive distribution and collection networks. Infrastructure capital costs and maintenance requirements are increased, and larger energy distribution losses could be expected.

● *Building-Site Relations.* Zoning yard and setback requirements set minimum distances between buildings and between buildings and the street. These requirements result in the centering of homes in the middle of their lots and necessitate less energy conservative, detached housing types. Common wall construction techniques, which can often reduce building heating and cooling loads, are prohibited.

For community energy systems, yard and setback requirements could be a barrier to innovative building orientation and solar collector application. Building lines on smaller lots must follow the lot lines, and the shape of the lot often determines the axis of the house. To orient buildings for maximum solar use, it may be necessary to position their southern facades a minimum distance from other buildings. Rigid yard and setback requirements would make this difficult.¹⁵

● *Mixed Land Use Communities.* The segregation of different land uses in separate zoning districts reflects a protective policy designed to ensure that each use is maximally productive. It is logical to site residences away from polluting industry, and to set schools apart from high density traffic

areas. There are, however, many cases in which the segregation unnecessarily contributes to energy waste. Traditional use districting, in general, denies the opportunity to plan for and design communities of diverse uses that mutually reinforce one another: commercial facilities that are within walking distance of residences, and industrial areas whose employment supports nearby residential centers.

- *ICES Component Siting.* While recent applications of Total Energy Systems in nonindustrial settings have experienced few siting problems related to local zoning regulation, it is still unclear whether such a favorable situation will generally be encountered in the case of Integrated Community Energy Systems. Many factors may contribute to a different public and regulatory reception, e.g.,

- Total energy systems were largely gas fired; ICES fuels may include coal, oil, and solid waste and thus have a greater potential for nuisance generation.
- ICES may include nonenergy utility generation facilities (e.g., water and waste treatment plants, incinerators, landfills) again with a higher potential for nuisance generation.
- ICES prime mover sizes could range as high as 30-100 MWe; whereas, TESSs are typically less than 5 MWe.

Application of ICES would require technologies that, under present district definitions, are often classified as industrial uses. These technologies would then be excluded from residential and commercial areas where potential applications exist. The light and heavy industrial uses that may be a part of new energy systems could be regulated in restricted zoning districts subject to site plan review. If the performance of a community energy system were to be environmentally tolerable, with acceptable levels of noise, pollution, and other nuisances, it could be included in districts where it would otherwise be banned, through the use of performance controls.¹⁵

- *Performance Standards.* Environmental performance standards that set maximum levels for a use's emission of air and noise pollution, and regulate glare, odor, etc., are commonly used controls for manufacturing and industrial districts. Control effort for ICES application probably will not be excessive in these districts. If, however, environmental performance standards are extended to include nuisances in residential and commercial zones, compliance

may be expensive. The restrictiveness of performance standards governing uses in nonindustrial districts remains a key uncertainty.

2.3.2 Summary of ICES/Zoning-Issue Interaction

Table 2.7 presents a set of general community types and the zoning issues which, in unfavorable circumstances, could restrict either the application of energy conservative community designs or the siting of specific ICES components.

Given that it will be possible, procedurally, to overcome these barriers, there will undoubtedly be increased administrative requirements of the developer. These may include possibly extensive public reviews in which it must be demonstrated that ICES technologies are environmentally compatible in the planned service territory and with surrounding areas, and whose applications are in accord with the community's comprehensive plan. All of this boils down to a requirement for unusually high levels of public administrative competence, and to increased delay and cost to the developer.

Community energy systems designed to service industrial complexes will experience few zoning problems. Industrial onsite generation of utilities is common practice today and will likely become more significant in the future, regardless of ICES efforts.

Potential zoning problems increase rapidly, however, as ICES application proceeds toward the single-family residence districts and toward complexes which exploit the advantages of mixed land use. Residential/commercial and residential/commercial/industrial ICES communities in which all of these issues are coincident will require the most developer-zoning regulation interaction.

In the following sections, a number of both conventional and novel zoning procedures are considered that may provide relief to developers confronted with the problems discussed above. Some of these procedures are common ordinance features that have enabled recent applications of Total Energy Systems. Others will be helpful in the future only to the extent that they gain more widespread local governmental acceptance.

TABLE 2.7. General ICES Community Types and Zoning Problems Likely to be Encountered

Community Type	Residential Density	Building Site Relations	Mixed Land Use	ICES Component Siting	Environmental Performance Standards
Single Family Residential	X	X		X	X
Multifamily Residential		X		X	X
Mixed Density Residential		X	X	X	X
Commercial Complex				X	X
Light Industrial Complex				X	X
Heavy Industrial Complex					X
Residential/Commercial Complex	X	X	X	X	X
Commercial/Industrial Complex			X	X	X
Residential/Commercial/Industrial Complex	X	X	X	X	X

2.4 ZONING PROVISIONS AND INNOVATIVE CONTROLS FAVORABLE TO ICES APPLICATION

Several existing zoning provisions and emerging regulatory innovations could offer developers more latitude in the design of energy conservative communities and in the application of Integrated Community Energy Systems. These include:

- *Zoning Regulation Exemptions* for community energy systems that are considered public utilities or are municipally owned,

- *Accessory Use* classification of minor ICES components such as building cooling towers and heat pumps,
- *Amendments* to use lists which would allow mixed land uses in restricted use districts, and to rezone land for the purpose of ICES siting,
- *Special Use* procedures that may allow nonindustrial district ICES siting while ensuring adequate public review,
- *Innovative Performance Controls* that enable developers to use energy conservative building and site designs,
- *Industrial Performance Standards* that will be necessary to ensure ICES' environmental acceptability, and
- *Planned Unit Development* processes that foster integrated community planning and design innovation, and which provide opportunities for municipal/developer bargaining to balance the financial requirements of the developer with the needs and desires of the community.

2.4.1 *Exemptions for Public Utilities and Government Buildings*

An initial review of Illinois Commerce Commission regulations¹ revealed that a community energy system is likely to be classified as a public utility unless it is municipally owned. If this proves to be typical, then siting restrictions in certain cases would be relaxed considerably because some localities exempt public utility uses from zoning regulation:

The regulation of this zoning ordinance shall not apply to any existing or proposed building or extension thereof, used or to be used by a Public Utility Corporation (Lebanon, Pa. Zoning Ordinance).

Other localities allow "Public, Quasi-Public, and Governmental buildings to be sited within any district, or to be exempted completely from regulation. Thus, under municipal ownership, a community energy system might not be subject to the use restrictions placed on private development.

2.4.2 Accessory Uses

"Accessory Uses" are uses, buildings, and structures normally associated with or incidental to a permitted or special use.¹⁹ Accessory uses are allowed by right in districts where the dominant use is permitted. Common examples of accessory uses include garages, private greenhouses, and children's playhouses in residential districts, and certain signs in commercial zones.²¹

Certain classes of ICES components probably will be considered accessory uses in most districts. These would include building space conditioning equipment such as cooling towers, chillers, solar collectors, and heat pumps, whether integrated within the principle structure or housed separately. If larger components, such as prime movers or waste treatment plants, were to be classified as permitted or special uses within a district, attendant structures, such as fuel storage tanks or bins and minor maintenance buildings, should be considered accessory uses and, hence would encounter no use restrictions.

2.4.3 Amendments

Amendment procedures are used to change either the text of a zoning ordinance or the zoning district map.¹⁴ Amendments to a zoning ordinance typically require a public hearing, a positive recommendation by the district planning commission, and action by the local governing council, a procedure that can take up to six months or longer.^{19,21} To find a certain new use appropriate in a district (as might be the case with ICES), a "public interest" test is commonly applied and it must be shown that the adoption of the amendment is "not solely for the interest of the applicant."¹⁹ *Amendments that supplement district use lists would be the most direct way with which ICES components could be permitted by right in nonindustrial districts.* The likelihood of this, however, appears questionable because the wholesale siting of energy production facilities near residential and commercial energy consumers would involve a major policy change in conventional use restrictions. Furthermore, the addition of energy facilities to nonindustrial district use lists would likely require extensive changes in other portions of the zoning ordinance, in particular, the adoption of residential and commercial performance standards regulating ICES environmental effects. Strict enforcement of residential nuisance regulations could cause widespread public disapproval because certain common residential activities, such as lawn mowing and barbequing, can violate even industrial performance standards.¹³

Rezoning or "contract zoning" of a parcel of land within or near residential or commercial districts to site community energy system components would probably be attacked as "spot zoning" and held invalid under court test.^{12,17} Many urban areas, however, are a patchwork of spot zones (often consisting of only one or two lots), whose locations are not in accordance with a comprehensive plan. Retrofit urban ICES applications, in which services are anticipated for several larger commercial or residential buildings, may be accomplished by simply rezoning a nearby lot to industrial use. Although such a siting strategy clearly is not in agreement with basic planning tenets, it cannot be applied generally, and in essence it relies on local authorities to bend regulations and possibly violate provisions of the zoning ordinance's enabling legislation. Such practices are, unfortunately, common.

2.4.4 *Special Uses*

A "Special Use" (special exception, conditional use) is a procedure in zoning that allows administrative review of certain uses that might not be compatible with development permitted by right in a given district.¹⁴

Special use requests, unlike zoning amendments, do not usually require legislative approval. Typically upon public hearing, recommendations by the district planning commission are reviewed and acted upon by the zoning board of appeals.^{19,21}

Special use permits are generally granted only for two classes of uses:

- (1) Uses either publicly operated or traditionally affected with a public interest, or
- (2) Uses entirely private in character but of such an unusual nature that their operation may give rise to unique problems with respect to their impact upon neighboring property or public facilities.^{16,17}

Special use provisions are often the only vehicle with which certain utility uses (e.g., electric substations, water treatment plants, or reservoirs) are allowed in residential and commercial districts. Similarly, ICES may include technologies that could conflict with the character of districts in which they are built because of the special services they may provide.

Zoning ordinances, however, vary widely in detail and flexibility of standards administrators must adhere to in evaluating special use requests. Special uses ordinarily are confined to a limited set of uses that are expressly listed for each district. Table 2.8 displays the special uses conditionally

TABLE 2.8. Special Uses and Standards for Permit Approval -
R4 Multifamily Residence District (Chicago, Il.)

Special Uses: R4 Multifamily Residence District (Chicago)

- Municipal or Privately-owned Recreation Buildings or Community Centers.
 - Public Utility and Public Service Uses, including:
 - a. bus turn-arounds (off-street)
 - b. electric sub-stations
 - c. fire stations
 - d. police stations
 - e. public art galleries and museums
 - f. railroad passenger stations
 - g. railroad right-of-way
 - h. telephone exchanges, microwave relay towers, and telephone transmission equipment buildings
 - i. water filtration plants
 - j. water pumping stations
 - k. water reservoirs
 - An automobile Parking Lot, in a Residence District on a lot not over 75 feet wide.
 - Playgrounds, privately owned and operated not for profit.
 - Open or enclosed accessory off-street parking facilities, for the storage of private passenger automobiles, when located elsewhere than on the same zoning lot as the principal use served.
 - Government operated Health Centers.
 - Institutions for the Care of the Insane or Feeble minded.
 - Parking Lots, open and other than accessory, for the storage of private passenger automobiles.
 - Radio and Television Towers.
-

Standards: No special use shall be granted by the Zoning Board of Appeals unless the special use:

- (1) a. Is necessary for the public convenience at that location;
 - b. Is so designed, located, and proposed to be operated that the public health, safety, and welfare will be protected; and
 - (2) Will not cause substantial injury to the value of other property in the neighborhood in which it is to be located; and
 - (3) Such a special use shall conform to the applicable regulations of the district in which it is to be located.
-

allowed in Chicago's R4 Multifamily Residence District and the standards that govern approval.²¹

In cases where prime movers, for instance, are not included in a district's special use list, and no other less cumbersome procedure is available with which development could proceed, a zoning ordinance amendment would be required to supplement the list. It is not clear that this circuitous, two-step procedure, i.e., amending a district's special use list and then applying for a permit, would be appealing to private developers of ICES communities. The administration of these procedures, if done sequentially, could take a year or longer.

Preliminary studies by the Trenton Grid-Connected ICES team indicate that the target site is located within a commercial district in which the system is a nonconforming use. Under private or utility ownership, it is anticipated that special use approval will be required.⁴

2.4.5 Innovative Performance Controls

Several newer performance control techniques and zoning procedures have been supplanting the traditionally inflexible lot, bulk, and height standards. By construction, the performance controls are essentially "self-executing," however, the developer gains design freedom not present with conventional regulation, yet attainment of the same zoning control objectives (e.g., adequate light and air) is preserved. The more common of these include:

- *Maximum Lot Coverage:* Maximum lot coverage is the fraction of lot area that is allowed to be covered by structures. Within this standard, developers maintain freedom to orient buildings in an unconventional manner, and in the absence of minimum side yard requirements they can use attached housing types.

- *Floor Area Ratio (FAR):* Similar to maximum lot coverage, but designed for multistory buildings, the floor area ratio (FAR) of a lot is simply the floor area of structures on a lot divided by the area of that lot. The FAR allows designers to choose from a variety of building forms in which the minimum standard is maintained.¹² Floor area ratios are used in place of, or in conjunction with, conventional yard, setback, and height restrictions.

- *Cluster Provisions:* Cluster provisions allow developers to reduce minimum lot size below that specified in district regulations to allow the grouping of structures in unconventional and possibly energy-conserving patterns.

gained by reduced minimum lot sizes can then be dedicated as communal open space, thereby preserving district net density requirements. Cluster zoning allows continued control of population density in areas of rugged terrain where large-scale site reconfiguration would be necessary if grid development were pursued.⁶ When used with innovative street designs, clustering can considerably reduce street requirements and automobile use, and decrease utility distribution system size.⁷

- *Density Zoning:* Rather than specifying minimum lot size and the housing types allowed in a district, density zoning techniques provide a maximum dwelling unit per acre standard without stipulations as to how this value is to be achieved. Under density zoning control, the developer can use locally higher densities (e.g., by clustering), can mix housing types, and can orient buildings without regard to restrictive setback and yard requirements.¹⁶

Each of these zoning controls and procedures can encourage creative building and site designs that foster energy conservation.

2.4.6 *Industrial Performance Zoning*

Industrial performance zoning is the application of staged performance standards rather than use lists to determine the appropriateness of a use within a particular district. Its purpose is to translate the classical light, medium, and heavy industrial categories into well-defined, meaningful terms that deal with environmental effects. Performance standards relate to process and not end product, and to effects rather than to a largely arbitrary industrial classification system.¹³

Regardless of the use list's merits of legislative and administrative ease, the use list is not able to resolve size and environmental impact differences among plants within the same industrial category. Performance standards present one way of distinguishing the nuisance created by a diesel generator from that of a large coal-fired electric station, or the adverse effects of a small community incinerator from one servicing a large city.

When compared to state and federal environmental regulations, however, the performance standards seen in most contemporary zoning ordinances are painfully crude. Emission limits for air pollution do not explicitly consider the more menacing offenders (e.g., SO_x , NO_x) and the stated maximum limits for particulates often are inconsistent in measurement terms with those currently enforced on the federal level. Some authorities suggest that all environmental

standards be removed from the zoning ordinance, to be covered by comprehensive codes regulating each particular nuisance.¹³

Use of strict performance standards in conjunction with a site plan review (for example, to obtain a special use permit) appears to be the likely regulatory procedure that developers will face in order to gain approval of ICES siting within a nonindustrial district.

2.4.7 Planned Unit Developments

Traditionally zoning has focused on the regulation of individual parcels of land, with the result that, *Parcels zoned alike tend to be developed alike.*⁵ The structure of zoning is such that it often lacks the flexibility required to deal with changing community conditions and design philosophies, in particular, those of energy conservation efforts that require novel community forms. Development, particularly in the era of the large-scale builder, and given the types of applications currently foreseen in ICES, is not restricted to a lot or parcel; hence there has been a need for a form of regulation with set standards governing projects on the neighborhood and community level. The Planned Unit Development technique has evolved since the early 1960's to meet this need.²

A Planned Unit Development (PUD) can be defined as:

*A land development project comprehensively planned as an entity via a unitary site plan which permits flexibility in building siting, mixture of housing types and land uses, usable open spaces, and the preservation of significant natural features.*²

In return for site plan review powers, zoning authorities may relax use, lot, or dimensional restrictions through such techniques as density zoning or clustering, so that the developer is given much more latitude in the design of structures, their arrangement on the land, and in the creative use of natural site features. Higher density residential configurations with reduced street requirements and building orientations that permit maximum solar use may become design strategies for the community. The total parcel, rather than a single lot, is the unit of regulation; controls apply to the entire development. Increased design flexibility allows project elements -- housing, streets, open spaces, utility systems and other nonresidential uses -- to be interrelated with one another to promote efficient energy use.

Several techniques are commonly employed to approve uses in Planned Unit Developments:⁹

- *Use lists:* Under this method the ordinance treats the PUD as an additional zone and lists the uses that are permitted within it. All of these uses are authorized as permitted uses as soon as the PUD is approved.
- *Combined use lists:* The uses permitted within a PUD are listed in the ordinance and are permitted as additional uses in any zone in which the planned development is approved.
- *Some uses permitted, some additional:* Some ordinances list the uses permitted within a PUD and then list additional uses which may be authorized by the agency that grants PUD approval.
- *Any use allowed subject to approval:* Some ordinances provide that any use be allowed within a PUD, if it is approved at the time the PUD is authorized.

Mixtures in dwelling unit type -- single, two, or multifamily housing -- are common today in residential PUDs. Mixtures of land uses, however, while becoming more prevalent, have been typically limited to convenience shopping, or in some cases, commercial facilities serving a market external to the PUD. Zoning ordinance provisions for other nonresidential PUDs appear widespread with "Planned Regional Shopping Centers," "Planned Industrial Districts," and "Planned Office and Research Parks" being leading candidates for ICES application.

The PUD is administered through either special permit procedures in conventional districts or by the use of a floating zone which may be designated a "Planned Development" district. Ordinarily, a separate section of the ordinance details the role of the PUD in the community's Master Plan, the procedures involved, and requirements of the developer with regard to plan content, and the standards governing PUD approval.

The PUD process generally begins with an informal yet public meeting between the developer and the local planning commission. Rough sketches may be presented to enable authorities to understand the project's location and anticipated design and timing, and thereby to enable the developer to gauge initial community reaction before committing significant amounts of resources. If, at this point, feelings on both sides are positive, special use or rezon-

ing procedures can begin, and more detailed preliminary plans can be developed and presented to the planning commission for review. Authorities may relax use, minimum lot, and bulk requirements to allow different housing types to be clustered and different uses to be mixed. Average project density may have to conform to district regulations, however, and density or floor area bonuses may be awarded to the developer in exchange for superior design or for the provision of schools and other community facilities. A final development plan review ensures that design specifics are acceptable and that the project conforms to all applicable ordinance regulations. The zoning authority also reassures itself that construction timing is such that municipal revenues at each stage of construction are adequate to support the resulting increased demand for public services.³ When final plans are approved, construction can begin. If construction has not begun within a designated number of years, special permits expire or the land falls back into its original district classification, and the PUD process must be repeated.

The PUD procedure of the model Marion County, Indiana zoning ordinance is displayed in Fig. 2.1. In this case, PUDs are administered via the floating D-P zone.

Two clear advantages of Planned Unit Development support arguments for its use⁷ in implementing community energy systems. The first involves the general relaxation of most PUD regulations regarding conventional building, lot, and use requirements. Development capital and energy use savings can thus be gained from improved community design. Secondly, PUDs, in general, have experienced relatively good market acceptance,¹⁶ and represent an increasingly popular land development technique with which application of community energy systems could be combined.

However, the problems that have been experienced with PUDs, whose utilities are provided by conventional sources, could be expected to intensify when ICES are included in the community designs. Typically, long PUD zoning review times and more comprehensive design requirements result in higher front-end costs to the developer. Higher costs, in turn, have been either passed on to the consumer, or have forced cancellation of development plans.⁷

2.5 SUMMARY AND CONCLUSIONS

Energy is only beginning to emerge as a consideration in local land-use planning, and until energy policies are integrated with other land use

Figure 2.1. PUD Zoning Procedure - Marion County, Ind.

policies, zoning regulation will not be conducive to innovative, energy-conservative land development techniques. Zoning, because it places numerous population density, building and site configuration, and use restrictions on land development, can only restrict the commercial application of Integrated Community Energy Systems.

In Sec. 2.3, five basic ICES/zoning problem areas were identified, and the community types that each would impact were summarized in Table 2.7. Many common ordinance provisions and innovative land use control procedures were described in Sec. 2.4, each of which in various circumstances would aid ICES development. Table 2.9 and the following discussion considers the applicability of these procedures to each ICES/zoning issue.

- *Residential Density:* Zoning traditionally controls residential density by specifying the minimum lot area required per dwelling unit and the housing types permitted within a district. Zoning district classifications invariably include a single-family residential district with relatively large minimum lot-size requirements resulting in low-density development that is non-energy conservative. Energy use efficiency in these districts is significantly lower than for higher-density development because of greater space-conditioning, street, and utility-line requirements, and fewer opportunities to use shared utility systems. Clustering of homes by consolidating portions of individual yards into larger communally used open spaces, can conserve energy by reducing street lengths and automobile use, and utility distribution system size. Density zoning, in which any dwelling type is permitted as long as net density standards for the entire subdivision are met, offers one control procedure that would allow an efficient and salable mix of housing forms. Density zoning, as well as cluster provisions, however, are not in widespread use.

- *Building Site Relations:* Zoning yard and setback requirements that set minimum distances between buildings and the street can limit the use of both energy-efficient, attached housing types and unusual building orientations that allow optimal, year-round solar access. Maximum lot coverage and floor area ratio controls, when used in place of fixed yard and setback standards, are examples of techniques that zoning authorities can use to permit energy conservative community design while still maintaining adequate control of development intensity.

TABLE 2.9. Applicability of Conventional and Innovative Zoning Procedures to ICES/Zoning Problem Areas

ICES/Zoning Issue	Zoning Provisions and Innovative Controls Favorable to ICES Application						
	Exemptions	Accessory Uses	Amendments	Special Uses	Innovative Performance Controls	Industrial Performance Zoning	PUD
Residential Density					X		X
Building/Site Relations					X		X
Mixed Land Use				X	X	X	X
ICES Component Siting	X	X	X	X		X	X
Environmental Performance Standards	X						

- *Mixed Land Use:* Zoning allowances for the development of energy-conservative mixed land use communities appear widespread for several combinations of land uses. Multifamily dwellings were permitted in commercial districts in about 50% of the zoning ordinances discussed in Sec. 2.2. One commonly-encountered, mixed-land-use community that would be relatively uneffected by use restrictions would be a regional shopping center containing medium- and high-rise apartments. Commercial uses were permitted in industrial zones in about 75% of the surveyed ordinances. An example of a potential ICES application in these districts would be combined Office and Industrial Parks. Opportunities for the mixing of all land uses within a single zone, however, do not appear common. In the two cases in which residential/commercial uses were permitted in an industrial zone, industrial uses were limited to those of a light manufacturing nature. ICES applications in these circumstances could include communities that integrated apartments within a Research and Development or Light Industrial Park environment.

- *ICES Siting:* ICES component siting in most localities will be difficult because many of the foreseen technologies are classified as industrial or heavy industrial uses and hence are not permitted in districts of primarily residential or commercial land use.

In some states, public utility statutes may be interpreted in such a way that ICES would be considered a public utility. Siting of individual components could then be unrestricted because of possible zoning regulation exemptions for utility buildings and structures. Zoning ordinances sometimes provide exemptions for publicly owned facilities; hence, in these cases where the ICES is wholly or jointly owned by a municipality, component siting would be allowed in any district.

If ICES technologies could be shown to be compatible with uses in nonindustrial settings (e.g., through environmental performance guarantees), then ordinance amendments that supplement use lists would be the most direct way in which components could be sited in residential or commercial districts. Special use provisions offer one procedure with which zoning administrators could selectively permit ICES application without giving blanket approval to the siting of other industrial uses that would not be desirable in nonindustrial zones.

In localities where industrial performance standards are used to classify uses according to environmental effect, the potential for routine siting of

heavier ICES components in light industrial or certain commercial zones would be considerably enhanced. Compliance cost would then be the relevant constraint to component implementation.

In zoning jurisdictions where all land uses in PUDs are subject to administrative approval, that is, no prior restrictions are placed on development land uses, ICES siting procedures would be combined with the PUD approval process. In this way, the ICES-serviced community would be regulated as a whole, and energy conservation benefits could be more rationally weighted against the risk of nuisance from onsite utility generation equipment. Because of the flexibility inherent in the PUD process, zoning authorities and developers have freedom to bargain toward a compromise that should provide adequate returns to the developer, and ensure ICES environmental and perhaps aesthetic compatibility within and near its service territory.

- *Performance Standards:* Environmental performance standards, which in part determine the types and levels of control technology required, will not be difficult to achieve in industrial districts. Because most localities do not allow the siting of what are considered high-nuisance-potential facilities (e.g., prime movers, waste treatment plants, incinerators) in nonindustrial zones, performance standards for these districts have not, as yet, been required. Some zoning ordinances, however, use the light industrial district performance standards (which are the most restrictive) for environmental control in all other nonindustrial districts. State air and noise emission regulations are often cited as the performance standards of the unrestricted, heavy industrial district.

None of the nonSMSA zoning jurisdictions surveyed had included environmental performance standards in their zoning ordinance. In these cases, environmental regulation was either covered under separate ordinances or deferred to a larger political unit.

In summary, zoning will present regulatory and procedural obstacles to the use of certain energy-conservative community designs, e.g., building orientations that permit efficient solar energy collection. Fortunately, adequate opportunity currently exists and conditions appear to be improving for the application of other possibly more important, energy-efficient design options -- high density or mixed density residential development, and certain types of residential/commercial and commercial/industrial communities. However, oppor-

tunities for the development of fully integrated land use communities, in which industrial uses are sited in appropriate areas near housing and commercial facilities, appear to be few.

Segregative use districting, which often results in a ban on major ICES component siting in nonindustrial districts, represents the most restrictive feature of conventional zoning practice on community energy system commercialization. Procedures exist, however, to provide special siting consideration for ICES technologies that can be demonstrated to be compatible with land uses ordinarily permitted in nonindustrial districts.

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3 *IMPACTS OF ENVIRONMENTAL AND UTILITY SITING LAWS ON COMMUNITY ENERGY SYSTEMS*

3.1 *INTRODUCTION*

Developers of community energy systems are faced with a complex of environmental and siting regulation which must be addressed in the initial stages of project planning. Aside from discouraging potential planners, compliance with the many federal, state and local regulations can be expensive, making otherwise cost beneficial projects uneconomical. A single ICES development, for example, could require a federal environmental impact statement, a state environmental impact statement, a national pollutant discharge elimination system (NPDES) permit, a state air pollution control permit, a local environmental permit to construct, a state utility commission environmental review, a new source review, a local zoning board review and site rezoning. At least two of the reviews just listed involve public hearings. Each of the reviews require that compliance with federal, state or local law be demonstrated depending upon the level of review. All reviews must be completed prior to commencement of construction. Time delays for project review caused by environmental regulation can run from one to two years. Extremely controversial projects could require additional hearing, review and revision delay. Aside from the environmental and siting review process is the cost of regulatory compliance.

Small ICES using internal combustion engines or gas boilers are not expected to present environmental problems. Thus, costs associated with siting and environmental emissions will be small. Control costs are limited to noise isolation and project aesthetics. Costs for impact statements, zoning review and new source review are also expected to be minimal causing few serious impediments to developers. Larger ICES using coal boilers, incinerators, multiple gas turbines or large oil boilers face considerable resistance from existing federal, state and local regulation. Emission control costs dramatically increase as systems increase in size and alternative fuels such as coal or high sulfur oils are used. Sulfur oxide emissions present the greatest danger to the economic viability of ICES. Control costs associated with SO₂ scrubbing can be disproportionate for the amount of utilities generated.

The purpose of this chapter is to summarize specific federal, state and local laws likely to be encountered by ICES planners and developers. Knowing the relationship between ICES size and design and federal, state and

local law provides a clear definition of regulatory obstacles. The influence of regulations on ICES vary. While some laws or ordinances dictate the siting of an ICES, others influence the system design, size and economics. Larger ICES, for example, designed to meet environmental and siting restrictions, require the uneconomical use of stack gas scrubbing, or the application of expensive fuels or uneconomical prime movers. If ICES are to be promoted as an energy conserving approach to utility generation, environmental and siting costs must be considered. Impediments caused by obsolete local zoning regulations and redundant environmental reviews can be minimized. Research can be directed toward providing an economical approach for environmentally acceptable fuel combustion and waste incineration.

3.2 SUMMARY OF ENVIRONMENTAL LAW RESTRICTING ICES DEVELOPMENT

Concern by citizens about the quality of their environment dates back to early zoning ordinances. By controlling the development and use of designated districts, local governments have been able to regulate, in a general sense, the activity or environment of a specifically zoned area. During the 1960's, when a national consciousness emerged for environmental quality, the federal government enacted legislation establishing funds and mechanisms for promulgating new environmental law. Federal activities in the Defense Department, Department of Interior, Department of Health, Education and Welfare, Environmental Protection Agency, Department of Transportation and Department of Energy have all established federal regulatory control over sources with emissions having the potential for environmental degradation. Some federal legislation established direct control over development of new sources while other federal legislation, such as the Coastal Zone Act provides for the establishment of state commissions responsible for regulatory control. A third type of federal legislation such as the Clean Air Act provides for state promulgation and enforcement of minimum federal standards. It additionally provides for assistance to the states to establish control programs and also necessitates the development of federal regulations. Since the late sixties, Congress has passed dozens of environmentally related bills. Three pieces of federal legislation stand out as having a potential impact on ICES development. They include the National Environmental Policy Act, the Clean Air Act and the Water Quality Control Act. These and other federal programs are listed in Table 3.1, along with a description of their impact on ICES. As a result of

TABLE 3.1. Summary of Federal Environmental Programs with a Potential for ICES Involvement

National Environmental Policy Act of 1969 (NEPA)

Requires environmental impact statements (EIS) for all federally involved projects. Impacts air, water, noise, solid waste and transportation aspects of ICES design.

National Ambient Air Quality Standards (NAAQS)

Under the Clean Air Act of 1970, the federal government set minimum air quality standards for particulates, sulfur oxides, carbon monoxide, nitrogen oxides, photochemical oxidants and hydrocarbons. States are required to regulate sources such that minimum (NAAQS) will be attained and maintained.

State Implementation Plans (SIPs)

State plans present a set of regulations governing emissions from sources of a pollutant such that NAAQS will be attained and maintained. State and local regulations impacting ICES are in the SIP.

New Source Performance Standards (NSPS)

Under provisions of the Clean Air Act, the federal government has set maximum emission standards for steam generators, incinerators, sewage treatment plants and certain coal preparation plants. NSPS will necessitate electrostatic precipitators and scrubbers on prime movers greater than 25 MW.

National Emission Standards for Hazardous Air Pollutants (NESHAP)

NESHAP restricts emissions of specific hazardous materials. Disposal of transformers using polychlorinated biphenyls are restricted. Otherwise, ICES are not influenced by this legislation.

New Source Review (NSR)

New source review allows for the air quality analysis of significant new sources which threaten the attainment and maintenance of air quality standards. NSR is expected on all new larger ICES.

TABLE 3.1. Summary of Federal Environmental Programs with a Potential for ICES Involvement (Contd.)

Prevention of Significant Deterioration (PSD)

Interpretation of PSD as part of the Clean Air Act of 1970 or passage of proposed PSD legislation will dramatically influence ICES development. PSD regulation could, if implemented, provide for more stringent standards in areas already meeting existing air quality standards. Such legislation could restrict development of rural areas. It may promote ICES development by restricting larger electric generating plants over a broad area.

Wild and Scenic Rivers Act of 1968

This act protects the free flowing nature of designated waterways. It is not likely to directly impact ICES but does not allow for regulation of siting to insure minimum streamflows.

Water Resources Planning Act

No significant direct impediments are expected from this legislation, however it does regulate water resource availability for all non-nuclear power sources.

Fish and Wildlife Coordination Act of 1934

This act restricts activities which degrade water quality to a point detrimental to fish and game in federal improvement projects. While direct regulation will not impact ICES, this legislation regulates thermal and liquid pollutant discharges from ICES sites.

Marine Protection, Research and Sanctuaries Act

This act, similar to the Clean Air Act, provides for minimum water quality standards. It impacts ICES by implementation of NPDES and state regulations.

National Pollutant Discharge Elimination System (NPDES)

Under Sections 501 and 307 of the Federal Water Pollution Control Act, EPA has set discharge standards for certain power generating facilities. Like NSPS, NPDES will impact discharges from larger ICES.

Wilderness Act of 1964

This act precludes incompatible water uses without specific congressional approval. Under isolated instances, this act could restrict ICES development in wilderness areas.

TABLE 3.1. Summary of Federal Environmental Programs with a Potential for ICES Involvement (Contd.)

Toxic Substances Act

This act restricts disposal of PCBs from power equipment. The act is not likely to influence ICES development.

Safe Water Drinking Act

While this legislation is not likely to severely impact ICES development, it does regulate entrainment ponds which could inject pollutants into drinking water.

Coastal Zone Management Act of 1972

This act provides for water management in coastal zones. State coastal zone agencies can restrict shoreline development and use of water resources under the authority of state and federal coastal zone legislation.

federal environmental activities, ICES planners must look to and be aware of federal controls.

Traditionally, law enforcement has been a state responsibility. Environmental enforcement and control is not an exception. Despite considerable federal activity, states are responsible for attaining and maintaining acceptable environmental quality in their jurisdiction. State Implementation Plans (SIPs) were first published in 1972. These plans presented the regulations and strategies to be implemented in order to achieve and maintain national air quality standards. SIPs did not require states to have regulatory uniformity but rather indicated that two general requirements be attained:

1. State regulations could not be less stringent than federal laws.
2. The implementation of state laws must allow for the attainment and maintenance of national standards.

Because of a variation in the character of geographical and demographic considerations, state environmental regulations have only a limited similarity. While noise, siting, and water regulations are similar from state-to-state, air pollution emission regulations can change considerably.

In addition to state law, localities, specifically large metropolitan areas, have established local regulations. Metropolitan areas like Chicago or Pittsburg have city or county agencies, both of which enforce local regulations which must be equal to or stricter than state regulations governing emissions from any given specific source category.

As a result of local, state and national concern for environmental emissions, the ICES planner must interact with all levels of government. Often there is little relationship between federal, state and local laws governing emissions of a pollutant and a source. Such unconformities require ICES planners to review all laws when evaluating environmental impacts of ICES. Figure 3.1 illustrates the hierarchy of environmental regulation. Zoning regulation, while least mentioned, has perhaps the greatest influence on ICES siting and design. At the grass roots level, local zoning laws often specify noise and visible emission performance standards for all new sources. Through the vehicle of local zoning codes, communities can prohibit development of a source considered unacceptable for the zoned area in which it is to be located. Re-zoning which is necessary for all ICES developments, requires public hearings, where local opinion can stop or significantly delay project development.

Figure 3.1 Hierarchy of Environmental Regulation

In order to assess the impact of environmental regulations on ICES, it has been necessary to assemble all pertinent federal regulations, state laws, and local regulations which govern ICES emissions. Because of the vast number of local zoning codes, it has not been possible to assemble all zoning restrictions. Instead, typical zoning codes have been studied which reflect the majority of zoning impediments for ICES developers.

3.3 DETERMINATION OF THE REGULATORY IMPACT OF FEDERAL, STATE AND LOCAL ENVIRONMENTAL LAWS

Given environmental regulation on three organizational/institutional levels and a variety of ICES designs and system sizes, it became necessary to systematically relate ICES designs to environmental and siting regulations.

While the number of possible ICES designs, concepts and configurations are too numerous to study as total systems, it was possible to subdivide ICES into component elements. Each element could then be assessed individually. When a specific ICES configuration is considered, the size and design of components can be identified. Regulatory impediments are then identified with each component in the system. The total of regulatory restrictions and control requirements for ICES components provide a reasonable estimate of the environmental/siting/control costs for the project.

The approach for determining regulatory impediments to ICES simplifies to identification of ICES components, estimation of environmental emissions by size and design of each component, collecting applicable regulations and relating emissions to emission limitations.

The last step of this procedure used a sieve approach. Emissions from ICES components were first passed through a sieve or filter representing federal regulation. Items passing the filter or sieve meet existing regulations and were passed to a sieve or filter representing state law. Components meeting state requirements were then passed through a sieve representing local regulations. When a given size component did not meet a regulatory test, a determination was made of the control equipment necessary to meet the emission limitation. The result of the process just described was the identification of components and the size of the components which would not meet federal, state or local law. Additionally, a determination was made of possible control techniques required to successfully meet those laws.

3.3.1 Identification of ICES Component Emissions

Energy system components can be described in a variety of ways. Because of the variation in potential designs, system components have been identified in general terms. Specific pieces of equipment are categorized under each system component.

Major system components have included the components in Table 3.2.

TABLE 3.2. ICES Components Reviewed

PRIME MOVERS

Coal Furnaces - Boilers - Steam Turbines

Oil Furnaces - Boilers - Steam Turbines

Gas Furnaces - Boilers - Steam Turbines

Internal Combustion Gas Engines

Internal Combustion Diesel Engines

Combustion Turbines

ANCILLARY HEAT SOURCES

Municipal Incinerators

Sludge Incinerators

Heat Exchangers

UTILITY GENERATORS

Hot Water Boilers

Chillers

Electrical Generators

Prime movers, are made up of a steam or compressed gas generator (a boiler or combustion chamber) and some sort of energy conversion device (a steam or gas turbine). Steam generators or boilers may be oil, coal or gas fired. Additionally, each type of fuel can be subdivided into a variety of grades. Prime movers considered included coal, oil and gas boilers capable of generating 10 MW to 100 MW of electrical energy. Fuels included north-western, central, northern Appalachian, central Appalachian and southwestern

coal, residual and distillate oils with sulfur contents of .01%, .1%, .5%, 1.0% and 3.0% sulfur and natural gas. Types of fuel burning equipment included underfeed stokers, spreader stokers, wet and dry bottom boilers and cyclone boilers.

The second category of prime movers evaluated included gas turbines operating from 150 kW to over 80 MW electrical generating capacity. Fuels included kerosene, natural gas, and diesel fuels from .01 to .5% sulfur content.

Diesel and gasoline-fueled internal combustion engines were considered in an operating range of 100 to 500 kW.

In total, prime movers generating from 100 kW to 100 MW were considered for air, water and noise emissions.

A second component evaluated as part of the ICES included auxillary heat sources. Incineration is the most common and environmentally detrimental auxillary heat source for ICES designs. Heat from incinerators can be used to generate steam for power generator or used for space heating or domestic utilities. Incinerator evaluation included municipal, industrial and sludge incineration facilities burning from 100 lbs per hour to over 500 tons per day.

The third major component in ICES is concerned with utility generation. Utility generators include chillers, electrical generators and heat exchangers. Also included in the category were transformers, substations, and other electrical transmission equipment.

To determine environmental emissions associated with each unit in the ICES, the most probable range of operating parameters were determined. Next fuel input was characterized. Whenever test or actual performance data was available, it was used as the best estimate of uncontrolled emissions. As a second alternative, emission factors were applied to estimate emission rates.

As expected, coal-fired boilers presented the worst environmental emission characteristics. Uncontrolled boilers in all size ranges, designs, and fuels violate either state, local or federal standards. Wastewater emissions from ash transport, cleaning and blowdown, although not subject to NPDES requirements, do require treatment. Noise levels from coal mill operation exceed federal and state noise standards requiring noise isolation. Siting and zoning regulation is particularly biased against location of such facilities near residential areas.

Aside from prime movers, incinerators present the next greatest expense from a control viewpoint. Larger incinerators to meet federal or state standards must employ air pollution control equipment. As in the case of other utility-oriented equipment, incinerators will require noise isolation to meet state noise regulations for residential land use.

3.3.2 *Overlay of ICES Emissions on Federal, State and Local Environmental Regulations*

As discussed earlier, a filtering or sieve technique was used to determine regulatory impediments to ICES components. Zoning regulation, because of its subjectivity, has been treated independently and will be discussed later.

When ICES component emissions are compared with federal air, water, noise and siting regulation, a matrix similar to Table 3.3 can be constructed. Federal regulation and legislation tends to be general in nature. Federal air pollutant regulations limiting emissions for new sources in specific source categories presents the most definitive set of federal rules applicable to ICES components. NPDES standards resulting from the Water Pollution Control Act are definitive but only apply to energy facilities larger than ICES. Aside from specific OSHA emission limitations, the federal government has not yet set specific rules governing energy generating facilities.

As previously mentioned, a variety of federal legislation influences ICES components either indirectly or in a general sense. Table 3.1 presents a listing of federal environmental/siting legislation and programs which have the potential for delay, redesign or resiting of an ICES.

It should be noted that aside from air and water laws, federal legislation tends to restrict development associated with ICES prime movers in areas where wildlife or natural water resources may be threatened.

If the spectrum of ICES components were passed through a filter consisting of federal regulations, the environmental controls illustrated in Table 3.4 would be required. It should be noted that the controls listed are a result only of direct federal regulation. Many federal programs such as the Clean Air Act or the Coastal Zone Management Act have resulted in the establishment of state regulations which impact ICES components. Table 3.5 summarizes the relative severity of federal, state and local programs on ICES components.

TABLE 3.3. Regulatory Impediments Resulting from Federal Regulation

Fossil Fueled Boilers	Particulates	SO ₂	NO _x	Water NPDES	Noise	Siting Legislation
<u>Fuel</u>						
Northwestern Coal	Violates NSPS at 25 MW all boiler types	Violates NSPS at 25 MW all boiler types	Underfeed stokers spreader stokers 25-60 MW meet regulations	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Central Coal	Violates NSPS at 25 MW all boiler types	Violates NSPS at 25 MW all boiler types	Underfeed stokers spreader stokers 25-60 MW meet regulations	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Northern Appalachian	Violates NSPS at 25 MW all boiler types	Violates NSPS at 25 MW all boiler types	Underfeed stokers spreader stokers 25-60 MW meet regulations	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Central Appalachian	Violates NSPS at 25 MW all boiler types	Violates NSPS at 25 MW all boiler types	Underfeed stokers spreader stokers 25-60 MW meet regulations	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Southwestern Coal	Violates NSPS at 25 MW all boiler types	All sizes and types of boilers meet federal standards	Only underfeed stokers 25-50 MW meet regulations	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Residual Oil	All units meet federal standards	Units meet federal standards burning maximum of .5% S fuel	Violates NSPS at 25 MW	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Distillate Oil	All units meet federal standards	Units meet federal standards burning maximum of .5% S fuel	Violates NSPS at 25 MW	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Natural Gas	All units meet federal standards	Units meet federal standards burning maximum of .5% S fuel	Violates NSPS when tangentially fired units are used	150 MW cutoff	Uncontrolled internal noise violates OSHA standards	Restricts siting in coastal zones or wildlife areas
Combustion Turbines	NSPS proposed for NO _x	Guidelines promulgated would require control				

TABLE 3.3. Regulatory Impediments Resulting from Federal Regulation (Contd.)

Fossil Fueled Boilers	Particulates	SO ₂	NO _x	Water NPDES	Noise	Siting Legislation
Internal Combustion Engines	No federal regulations except those governing equipment manufacturing.					
Incinerators	Violate particulate NSPS regulations for larger incinerators (> 50 T/dy)	No federal regulatory control.				

TABLE 3.4. Regulatory Controls Required by
Direct Federal Regulation

-
1. NSPS emission requirements for particulates covering operation of coal fired boilers and incinerators.
 - A. Requires use of an electrostatic precipitator and/or scrubber on all units greater than 250×10^6 Btu/hr.
 - B. Requires use of a water spray system, electrostatic precipitator and/or scrubber on multiple chamber units burning over 50 tons of refuse per day.
 2. NSPS emission requirements for sulfur oxide emissions covering operation of coal and oil fired boilers and incinerators.
 - A. Requires use of low sulfur pretreated or western coal or application of flue gas desulfurization (FGD) on coal boilers greater than 250×10^6 Btu/hr.
 - B. Requires use of low sulfur fuel (.5% sulfur or less) or application of flue gas desulfurization on units larger than 250×10^6 Btu/hr.
 3. NSPS emission requirements for nitrogen oxides.
 - A. Requires two stage combustion, low excess air and/or flue gas recirculation for all coal boilers greater than 250×10^6 Btu/hr.
 - B. Requires the above controls for all oil fired boilers greater than 250×10^6 Btu/hr.
 - C. Requires the same controls for all gas fired boilers greater than 250×10^6 Btu/hr.
-

TABLE 3.5. Relative Severity of Regulatory Control on ICES Components

	Air Pollution						Water Pollution			Hazardous Materials		Noise		Special Permits and Local Siting Regulation	
	Federal				State Regulations	Local Regulations	EIS	NPDES	Local Regulations	EIS	NESHAPS	EIS	State Regulations	Local Regulations	
	EIS	NSPS	NSR	PSD											
<u>PRIME MOVERS</u>															
coal-fired steam boilers	1	1	1	1	1	1	3	2	2			2	2	2	1 - Zoning Restrictions
oil-fired steam boilers	2	2	2	2	2	2	3	2	2			2	2	2	1 - Zoning Restrictions
gas-fired steam boilers	3	3	3	3	3	3	3	2	2			2	2	2	1 - Zoning Restrictions
combustion turbines	3	3	3	3	3	3	3	2	2			1	1	1	2 - Zoning Restrictions
diesel engines	3	3	3	3	3	3	3	3	3			3	2	2	3 - Zoning Restrictions
spark ignition engines	3	3	3	3	3	3	3	3	3			3	2	2	3 - Zoning Restrictions
<u>ANCILLARY HEAT GENERATORS</u>															
refuse incinerators	1	1	1	1			3	2	2			3	2	2	1 - Zoning Restrictions
sludge incinerators	1	1	1	1			3	2	2			3	2	2	1 - Zoning Restrictions
heat recycling/heat exchangers							3	3	3						
<u>UTILITY EQUIPMENT</u>															
chillers													1-2	1-2	
heat exchangers												3			
electrical generators												3	2	2	
transformers/transmission lines/substations	3									3	2	3	1-2	1-2	
<u>SUPPORT EQUIPMENT</u>															
coal mills/pulverizers	2											2			1 - Zoning Restrictions
oil fuel storage/transportation	2														1 - Zoning Restrictions
coal storage/transportation	2						2	2							1 - Zoning Restrictions
cooling towers	2						2	2	2			3	2		

1 - Severe impediment; 2 - impediment requiring design consideration; 3 - nuisance possible requiring attention.

In addition to federal controls listed are environmental impact statement requirements and general siting restrictions. Since the predeterminant of an environmentally acceptable EIS is conformance with state and local regulation, all ICES components should be subject to state and local regulatory screening. Assessment of a project such as EU (Environmentally Unacceptable) or ER (Environmental Reservations) because of nonconformance with state or local regulations will prevent commencement of a project and require at least four additional months for revision, review and acceptance of project modifications.

Unfortunately for comparison and analysis, state and local environmental regulations are not uniform across the country. Sulfur oxide emissions in the northeast, for example, place severe restrictions on coal burning while southwestern states tend to have stricter particulate emission standards.

The same methodology applied to federal regulations has been applied to state and local regulations. Analysis of state SIPs indicate that 41 states have more restrictive particulate regulations, 39 states have more restrictive SO₂ regulations and 7 states have more restrictive NO_x regulations. In most cases, additional state regulatory control lowers the 250 x 10⁶ Btu/hr boiler size to include all size units.

While some states have enacted statewide or local regulation which lower the cutoff point, certain states have found it necessary to also reduce the emission level allowed under federal standards. Table 3.6 summarizes the states which have reduced allowable emission rates below federal limits.

Appendix J details the additional control placed on fossil boilers as a result of state particulate regulations.

Table 3.7 illustrates the particulate control removal efficiencies required to meet lower state emission limitations. Collection efficiency requirements increase dramatically as allowable particulate emissions decrease. Cyclone boilers, for example, burning central Appalachian coal need about 10% control to meet a .8 lb/10⁶ Btu requirement. To meet particulate standards in Maine, Massachusetts or Maryland, the same boilers require 90% control.

Appendix K presents state requirements for sulfur oxides. As shown in Table 3.6, considerable control is required to meet emission limits in some states while others allow the burning of low sulfur coals. Additional NO_x re-

TABLE 3.6. States Having More Stringent Emission Limitations

	Particulates	SO _x	NO _x	Thermal Discharge
				(All States Except)
Boilers	Maryland	Connecticut	New Mexico	Alaska
	Massachusetts	Illinois		Arizona
	New Mexico	New Mexico		California
	Pennsylvania	Pennsylvania		Delaware
	Vermont	Rhode Island		D.C.
	West Virginia	Wyoming		Illinois
	Illinois	New York		New Hampshire
	California	New Jersey		Oklahoma
		Michigan		Puerto Rico
		Maryland		
		Idaho		
		Hawaii		
		Delaware		
		California		
Incinerators	All states have more stringent regulatory control			

TABLE 3.7. Particulate Control Removal Efficiencies Required to Meet State Regulations (Coal Boilers)

	.1 lbs/10 ⁶ Btu %	.3 lbs/10 ⁶ Btu %	.6 lbs/10 ⁶ Btu %	.8 lbs/10 ⁶ Btu %
<u>Northwestern Coal</u>				
Underfeed Stokers	87	61	22	0
Spreader Stokers	98	94	88	84
Wet Bottom Boilers	-	-	-	-
Dry Bottom Boilers	98	95	91	88
Cyclone Boilers	87	61	-	0
<u>Southwestern Coal</u>				
Underfeed Stokers	94	81	63	50
Spreader Stokers	99	97	94	92
Wet Bottom Boilers	-	-	-	-
Dry Bottom Boilers	99	98	96	94
Cyclone Boilers	94	81	-	50
<u>Central Coal</u>				
Underfeed Stokers	88	64	29	5
Spreader Stokers	98	95	89	85
Wet Bottom Boilers	-	-	-	-
Dry Bottom Boilers	99	96	92	89
Cyclone Boilers	88	64	-	5
<u>Northern Appalachian</u>				
Underfeed Stokers	92	76	52	36
Spreader Stokers	99	96	93	90
Wet Bottom Boilers	-	-	-	-
Dry Bottom Boilers	99	97	94	92
Cyclone Boilers	92	76	-	36
<u>Central Appalachian</u>				
Underfeed Stokers	89	68	35	14
Spreader Stokers	98	95	90	86
Wet Bottom Boilers	-	-	-	-
Dry Bottom Boilers	99	96	92	90
Cyclone Boilers	89	68	-	14

quirements are presented in Appendix L. These appendices express the additional prohibition on the use of fossil fuels caused not by federal new source performance standards, but by state emission limitation regulations.

Particulates from incinerators and sulfur oxide emissions and thermal discharges from power generating facilities are of prime concern as reflected by the stringency of local law.

To summarize environmental regulatory control, the federal government has established regulations restricting pollutant emissions from ICES components. The components regulated include fossil-fueled boilers and incinerators. Some states and their municipalities have established laws which restrict those emissions further. The resultant effect is an increased need for particulate, SO₂ and thermal control.

The federal government, while establishing general noise standards for construction equipment, and noise exposure standards for HUD projects, has not yet established national emission limitations for ICES type sources. States, however, have three categories of law which can be used for enforcement of noise emissions. Four states, including Colorado, Illinois, New Jersey and Oregon have passed state-wide noise limitation regulations for residential and/or commercial land use.

States also have OSHA standards for noise exposure which can be enforced to limit internal noise exposure. OSHA standards restrict noise exposure in power plants to 90 dba for eight hours with a sliding scale of noise levels and exposure durations to 115 dba for one quarter hour.

The third category of regulations and perhaps the category having the greatest influence on ICES design is the local or county zoning ordinance. Almost every zoning law has a provision for noise emissions. More sophisticated ordinances have performance standards restricting maximum sound levels by frequency of emission and land use. Local zoning sound restrictions necessitate noise control on equipment listed in Table 3.8.

3.4 STATE AND LOCAL SITING REGULATION ON ICES DEVELOPMENT

When siting regulation is discussed, environmental regulation is implied since the foundation for most siting law is environmental preservation. Often in the case of zoning ordinances, regulatory control has created areas

TABLE 3.8. ICES Equipment Subject to Noise and Vibration Isolation

Coal Mills	D-C Generators
Pumps	Demineralizers
Fans	Flue Gas Exhausters
Compressors	Substations
Combustion Turbines	Vacuum Piping
Turbine Generators	Control Valves
Pressure Reducing Stations	Cooling Towers

of uniform land use or set minimum performance standards as designated by the community. State utility commissions have set standards for air pollution, water pollution, water use, and land use for electrical generating plants and transmission lines. Thirteen states require review of air pollution controls as part of their certification process, twelve require a review of water pollution controls, ten a review of water use, and fourteen a review of land use. Appendix G presents a summary of states giving the utility commission authority for environmental review as part of certification.

Zoning and utility siting certification generally reinforce compliance with local environmental law. In the case of noise control and site parameters, local ordinances can greatly inhibit project construction.

As previously discussed, applications of Total Energy Systems in nonindustrial settings have experienced few siting problems related to local zoning regulation, yet it is still unclear whether such a favorable situation will generally be encountered in the case of Integrated Community Energy Systems. Many factors may contribute to a different public and regulatory reception.

Total energy systems were largely gas fired, while ICES fuels may include coal, oil, and solid waste and thus have a greater potential for nuisance generation. ICES may include nonenergy utility generation facilities (e.g., water and waste treatment plants, incinerators, landfills) again with a higher potential for nuisance generation. ICES prime mover sizes could range as high as 30-100 MWe; whereas, TESSs are typically less than 5 MWe.

Application of ICES would require technologies that, under present district definitions, are often classified as industrial uses. These technologies

would then be excluded from residential and commercial areas where potential applications exist. The light and heavy industrial uses that may be a part of new energy systems could be regulated in restricted zoning districts subject to site plan review. If the performance of a community energy system were to be environmentally tolerable, with acceptable levels of noise, pollution, and other nuisances, it could be included in districts where it would otherwise be banned, through the use of performance controls.

Examination of problem areas associated with local zoning can be focused on five specific issues:

<u>ICES/Zoning Issue</u>	<u>Primary Restrictive Ordinance Feature</u>
1. Residential density required to support a community energy system.	Minimum lot size.
2. Building-site relations in multi-building complexes	Yard and setback requirements.
3. Opportunities for mixed land use communities.	Use districting.
4. Siting of ICES components in nonindustrial districts.	Use districting.
5. Level of environmental control effort required for ICES application.	Performance standards.

Chapter 2 summarized zoning problems likely to be encountered by ICES redevelopment. Existing zoning provisions and emerging regulatory innovations could offer developers more latitude in the design of energy conservative communities and in the application of Integrated Community Energy Systems. These include:

- *Zoning Regulation Exemptions* for community energy systems that are considered public utilities or are municipally owned.
- *Amendments* to use lists which would allow mixed land uses in restricted use districts, and to rezone land for the purpose of ICES siting.
- *Accessory Use* classification of minor ICES components such as building cooling towers and heat pumps.

- *Special Use* procedures that may allow nonindustrial district ICES siting while ensuring adequate public review.
- *Innovative Performance Controls* that enable developers to use energy conservative building and site designs.
- *Industrial Performance Standards* that will be necessary to ensure ICES' environmental acceptability.
- *Planned Unit Development* processes that foster integrated community planning and design innovation, and which provide opportunities for municipal/developer bargaining to balance the financial requirements of the developer with the needs and desires of the community.

3.5 COST OF ICES REGULATORY COMPLIANCE

Costs associated with regulatory compliance can be subdivided into six categories:

1. Costs associated with engineering and technical environmental studies of the ICES,
2. Costs associated with liaison with federal, state, and local regulatory bodies,
3. Costs associated with construction and operation of control equipment,
4. Costs associated with environmental sampling, monitoring, and analysis,
5. Costs associated with required use of alternative fuels, and
6. Costs associated with nonoptimum land use to meet zoning requirements.

When comparing the above costs with larger energy facilities or on a cost per unit of energy delivered, the ICES is unable to spread expenditures over a large base. The result is larger per unit or per capita control costs for ICES than for larger central stations. Costs relating to engineering studies and agency liaison can vary greatly depending upon the complexity, size, and location of the ICES development. When comparing ICES costs for these operations with central system costs, consideration must be given for the fact that ICES analysis considers an entire community development rather

than a single facility. Planning and implementation may occur over several years. Given a two year planning horizon for small ICES (up to 5 MW) and five years for larger ICES, a rough estimate of ICES environmental engineering analysis and liaison activities would be from \$10K to \$150K, or from \$6 to \$100 per kW on small developments and from \$1.5 to \$30 per kW on large developments. Alternative unit costs for large central systems are likely to be less. For a 1,000 MW plant, the lowest level of ICES engineering costs would allow over \$1.5 million dollars to over \$30 million dollars for environmental planning engineering and analysis. Such costs would be less than \$1 per kW of installed capacity.

When comparing costs for sampling, analysis, and monitoring, the larger central plant again has the advantage of economy of scale. Large central plants require continuous monitoring, site monitoring, and sampling calibration checks from two to four times per year. Despite large expenditures for sampling and monitoring, these costs are not expected to exceed \$.25 per kW of installed capacity annually. Small ICES have no monitoring or sampling requirements. Data required for impact statements can be obtained from alternative sources with no cost impact to the developer. ICES greater than 25 MW, however, as in the case of environmental analysis, are confronted with continuous monitoring requirements, sampling and calibration and the added problem of a high residential density near the source. Sampling, monitoring, and analysis for a 25 MW plant could easily exceed \$1 per kW of installed capacity annually.

Costs associated with nonoptimum land utilization are difficult to assess. Both central stations and ICES will present land utilization problems to local planners. Large central stations require larger power facility sites and transmission pathways. ICES, while not confronted with cooling pond and transmission line land use problems, must satisfy mixed land use zoning requirements. Again, larger ICES using large fossil-fired units (above 5 MW) are likely to have proportionately greater siting problems.

The final cost components associated with environmental regulatory control is construction and operation of control equipment and the use of alternative fuels.

Particulate control can be achieved using either fabric filtration on smaller combustion sources or electrostatic precipitators on larger units.

Scrubbers can also be used for particulate control but remains the most costly control alternative when only particulate control is required. Based upon data from the NUCLA Station of the Colorado Ute Electric Association, unit capital costs of \$87/kW were estimated for particulate control, with annual operating costs totalling 1.53 mills per/kWh. Comparable costs for particulate control in larger central stations is about \$65/kW¹ with an annual operating cost of about .1 mill per/kWh. In the case of flue gas desulfurization, the cost penalty for smaller systems is more apparent. Based on joint TVA-EPA data, capital costs for small fossil plants range from \$60/kW to \$98/kW using lime as the least capital cost intensive and the Cat-ox process as the most expensive. For power plants in the 50 MW range, a cost of \$115 to \$120² per kW is more realistic. These costs contrasted with capital costs of \$33/kW and \$70/kW for a 1,000 MW plant. Estimates made in the same study are based upon a 30-year life and onsite solid waste disposal with 90% control.³ Operational costs for flue gas desulfurization units are relatively constant over size in the range of 2.2 to 3.3 mills/kWh.

Thermal control is the single emission problem which larger central plants must control, while larger ICES need no control. Based on recent costs of cooling pond and tower operation, capital costs for large central plants are about \$6 per kW installed capacity with annual operating costs of .18 mills⁴ per kWh.

Another approach to emission limitation of particulates, sulfur oxides, and nitrogen oxides is the use of alternative fuels. Table 3.9 presents fuel prices by sulfur content. Based upon a tally of fuel prices by sulfur content on coal orders less than 500×10^3 tons, use of low sulfur coal appears to be the least cost SO_x control option. Price differentials for coal burned in ICES and meeting environmental regulations against coal violating regulations is minimal when compared to the cost of FGD. Some northeastern states will still require scrubbing or use of lower sulfur alternative fuels.

Oil does not appear to have the same price structure as coal. The cost differential between high and low sulfur oil (between .2% and 2%) is as much as \$.70 per 10⁶ Btu. Operation of a 50 MW power plant 8,000 hours per year would cost an additional \$3.2 million in fuel annually. This compares with an approximate \$8 million cost for a scrubber with total annual charges of \$1.0 million (excluding capital charges).

TABLE 3.9. Average Prices for Fuel by Sulfur Content
(¢/10⁶ Btu)

	Capital Costs						Operating Costs					
	\$/KW						Mills/kWh					
	Environmental Engineering Analysis	Particulate Control	SO ₂ Control	Water Pollutant Control	Thermal Discharge	Total Capital Charges	Particulate Control	SO ₂ Control	Water Pollutant Control	Thermal Discharge	Alternative Fuels	Total Operating Charges
Central Station Plants												
1000 MW coal	< 1	65	70	1.5	5.7	142.2	.1	1.7	.1	.18	-	2.08
1000 MW oil	< 1	-	50	1.5	5.7	57.2	-	1.7	.1	.18	-	1.09
Small ICES	6-100	-	-	-	-	6-100	-	-	-	-	-	0.00
Large ICES												
Coal (> 25 MW)	2-30	87	98	1.5	-	188.5	1.5	2.3	.1		-	3.90
Oil (> 25 MW)	2-30	-	98	1.5	-	101.5	-	2.3	.1		7.7	2.40

In this case, low sulfur fuel oil would be more economical only if the utilities cost of capital exceeded 22%. Table 3.10 summarizes comparative costs for central plants and ICES to meet existing regulatory control requirements.

3.6 SUMMARY AND CONCLUSIONS

Federal environmental regulations reinforced, or strengthened by state and local law, has impacted smaller energy systems by:

- Requiring application of flue gas desulfurization on larger fossil-fueled boilers and sludge incinerators.
- Requiring application of electrostatic precipitators on large coal-fired boilers and incinerators.
- Requiring PUD or special use zoning with mandatory rezoning hearings.
- Prohibiting economical application of coal-fueled prime movers.
- Requiring rezoning and special consideration under existing siting and zoning laws.

Siting and environmental issues worthy of additional consideration include:

- Revising model zoning ordinances to include ICES as a special use category.
- Revision of model zoning ordinances allowing for mixed use districts in ICES developments.
- Review and improvement of SO₂ control technology for small coal-fired units.
- Assessment of coal gasification as a pretreatment approach for small boilers.
- Additional investigation of control technologies for small energy systems.
- Additional investigation of the cost impacts of federal, state and local environmental regulation on small energy systems.

TABLE 3.10. Average Prices for Fuel by Sulfur Content
c/10⁶ Btu

Region	Coal							Oil ^a							Gas Orders Less Than 100 x 10 ³ MCF
	Orders Less than 500 x 10 ³ Tons							Orders Less than 100 x 10 ³ Bbls							
	<0.5	.5-1-1.0	1.01-1.5	1.51-2.0	2.01-2.5	2.51-3.0	3.01-3.5	<0.1	.11-.20	.21-.50	.51-1.0	1.01-1.5	1.51-2.0	>2.0	
New England	-	-	-	-	125.3 ^b	-	-	245.4	236.6	243.1	222.4	174.0 ^d	174.0 ^d	188.2 ^c	168.3
Middle Atlantic	-	87.1	92.8	100.0	92.2	121.3 ^c	-	258.0	248.6	246.9	202.6 ^d	200.0 ^d	185.6 ^d	171.0 ^d	139.5
East North Central	95.9 ^d	125.5	102.6	112.1	91.8	101.7	85.2	251.4	245.2	238.2	248.9	187.9 ^d	168.6 ^c	-	143.5
West North Central	70.2	99.9	115.1	120.9	103.3	97.7	75.9 ^c	255.5	235.6	232.8	217.6	234.4 ^c	181.2	161.0	94.6
South Atlantic	-	121.3	106.3	101.3	139.8 ^c	115.4 ^c	103.9 ^d	239.4	233.8	242.6	191.2 ^c	185.5 ^d	236.6 ^c	176.9	111.1
East South Central	-	99.8	96.6	97.3 ^d	118.2 ^c	100.0 ^d	77.6 ^c	-	241.4	245.8	227.5	-	188.9 ^d	166.0 ^d	90.8
West South Central	97.4	27.6 ^d	-	-	-	-	-	232.7	222.1	203.0	188.4	163.2 ^c	-	237.8 ^c	85.9
Mountain	59.7 ^c	65.5	-	-	-	-	-	275.8 ^c	221.3	223.8	173.6	-	-	-	92.7
Pacific	-	75.2 ^b	-	-	-	-	-	271.9 ^c	256.2	256.1	227.6 ^d	186.8 ^d	168.1 ^d	230.2 ^d	127.4

^a Ranges indicate sulfur content of fuel.

^b Coal only used at one plant in region; above specified limit.

^c Only one plant in region below specified limit.

^d No plants in region below limit; plants above limit used.

REFERENCES
Chapter 3

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3. Jonakin, J., *Flue Gas Desulfurization*, American Public Power Association Workshop, (February, 1975).
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APPENDIX A

Definitions, Assumptions, Nomenclature and Abbreviations

Nomenclature/Abbreviations:

AQCR - Air Quality Control Region	ppm - Parts per million by volume
E - Allowable emissions	Q - Heat input rate (MMBtu/hr)
EPA - U.S. Environmental	%S - Percent sulfur by weight
FGD - Flue gas desulfurization	SCFM - Standard cubic feet per minute
MMBtu - Million British thermal units	SIP - State Implementation Plan
MW - Megawatts	# - Pounds
NAAQS - National Ambient Air Quality Standard	

Transmission Efficiency:

$$\begin{aligned}
 \text{Efficiency} &= 1 - (\text{five loss}) (\text{Distance}) \\
 &= 1 - (.00014) (5) = .99930 \\
 &\approx 1.0
 \end{aligned}$$

Particulate Emissions Removal Efficiency Requirement

E = (EF) lbs/Ton Coal input

H = Heating Value/lb Coal Input = (HV) 2000 Btu/lb

$$E/H \text{ lbs}/10^6 \text{ Btu} = \frac{\text{Emission Factor}}{(\text{HV Coal})^2} \times 10^6 \text{ lbs}/10^6 \text{ Btu}$$

$$\text{Required removal efficiency} = \frac{(E/H - \text{Regulation})}{E-H}$$

Prime Mover Efficiency:

Heat Rate: Thermal energy (Btu) required to generate one kilowatt-hr of electric power at the generator

Assume capacity factor of 75%

Heat input requirement = Gene

(Power generation MW) (1000 kW/MW) (.75) (heat rate)

$$\text{Efficiency} = \frac{3413 \text{ Btu/kW-hr}}{\text{Heat Rate}}$$

Energy-Heat Input Equivalencies:

1.0 (Megawatt Elect.) = 10^7 Btu/hr
for 34% station efficiency

10^6 Btu/hr (Firing Rate) = .1 MW electrical 34%

10^6 Btu/hr firing rate = 700 lbs stm/hr
75% boiler efficiency

Boiler Size Characterization:

Residential $< 3.3 \times 10^5$ Btu/hr

Commercial 3.3×10^5 to 10^7

Industrial 10^7 to 5×10^8

Utility $> 5 \times 10^8$

APPENDIX B

Composition and Heat Contents of
Common Fossil Fuels

Composition of Fuels and Fuel Oils

<u>Grade</u>	<u>%S</u>	<u>Ash</u>
1-D	.5	.01
2-D	1.0	.02
4-D	2.0	.1

Crude, Distillate Fuel Oil

<u>Crude</u>	<u>%S</u>	<u>Btu/lb</u> <u>(10³)</u>	<u>lb/gal</u>
Pennsylvania	.06	19.50	6.769
Texas	1.75	19.46	7.286
Oklahoma	.4	19.5	7.236
California	.75	18.91	7.636
Mexican	4.5	18.75	8.120
Gasoline	.08	20.75	6.125

Fuels for Use In Gas Engines

<u>Gaseous Fuel</u>	<u>HVV</u> <u>(Btu/ft³)</u>	<u>LHV</u> <u>(Btu/ft³)</u>
Dry, processed natural gas	1,000	900
Propane HD5 or equivalent	2,500	2,500-2,174
Butane	3,200	3,200-2,783
Natural gas w/propane-air	1,000	900
Sewage gas	600	600-522
Natural gas w/hydrogen	800	720

APPENDIX C

Building and Component Sizes for Proposed ICES Developments

APPENDIX C. Building and Operating Components and Sizes for Previously Studied ICES

ICES (SINGLE BUILDING) TYPES	LOCATION	SPECIAL NOTES	BUILDING TYPES	SQUARE FT. (1000's)	PRIME MOVERS			PEAK SUPPLEMENT		COOLING		REFERENCE NUMBER
					TYPE	SIZES	SIZE 14 KW/sw.ft.	BOILER	SIZE hp/sq.ft.	SIZE tons/sq.ft.		
MIUS MODEL A	MINNEAPOLIS	-	720 GARDEN APARTMENTS	648	GAS IC ENGINE	4@ 500 kW	3.1	2@ 400 hp.	1.2	1.8	11	
MIUS MODEL A	PHILADELPHIA	-	720 GARDEN APARTMENTS	648	GAS IC ENGINE	4@ 500 kW	3.1	2@ 250 hp.	0.8	1.8	11	
MIUS MODEL A	DALLAS	-	720 GARDEN APARTMENTS	648	GAS IC ENGINE	4@ 500 kW	3.1	2@ 200 hp.	0.6	1.9	11	
MIUS MODEL A	PHILADELPHIA	INSULATION SUBSTANDARD	720 GARDEN APARTMENTS	648	GAS IC ENGINE	4@ 500 kW	3.1	2@ 350 hp.	1.1	1.6	11	
MIUS MODEL C	PHILADELPHIA	INSULATION SUBSTANDARD	1080 GARDEN APARTMENTS	972	GAS IC ENGINE	8@ 500 kW	4.1	2@ 150 hp.	0.3	1.0	11	
MIUS MODEL C	DALLAS	1/3 HEAT PUMPS	1080 GARDEN APARTMENTS	972	GAS IC ENGINE	7@ 500 kW	3.6	2@ 100 hp.	0.2	1.3	11	
MIUS MODEL J	PHILADELPHIA	1/3 HEAT PUMPS	520 HIGH RISE APARTMENTS	506	GAS IC ENGINE	4@ 500 kW	4.0	2@ 150 hp.	0.6	1.2	11	
NASA-MIUS COMPARISONS	HOUSTON		648 GARDEN APARTMENTS	547	DIESEL ENGINE	4@ 1035 kW	7.6	2@ 71 hp.	0.3	2.5	1	
NASA-MIUS COMPARISONS	HOUSTON		HIGH RISE OFFICES	183	GAS TURBINE	4@ 350 kW	7.7	NONE	0	3.4	1	
NASA-MIUS COMPARISONS	HOUSTON		210 HIGH RISE APARTMENTS	306	DIESEL ENGINE	4@ 478 kW	6.2	1@ 60 hp.	0.2	3.2	1	
NASA-MIUS COMPARISONS	HOUSTON		SHOPPING CENTER	650	DIESEL ENGINE	4@ 1450 kW	8.9	NONE	0	3.0	1	
NASA-MIUS COMPARISONS	HOUSTON		HIGH SCHOOL	178	DIESEL ENGINE	3@ 478 kW	2.7	INCINERATOR 39 hp.	0.2	2.2	1	
NASA-MIUS COMPARISONS	HOUSTON		HOSPITAL	109	DIESEL ENGINE	3@ 400 kW	11.0	NONE	0	3.7	1	
RAND OFFICE BUILDING	NEW YORK		OFFICE BUILDING	360	DIESEL ENGINE	6@ 467 kW	7.8	3@ 112 hp.	0.9	3.1	10	
RAND OFFICE BUILDING	NEW YORK	HALF LIGHTING	OFFICE BUILDING	360	DIESEL ENGINE	7@ 230 kW	4.5	3@ 112 hp.	0.9	2.2	10	
LACLEDE OFFICE BUILDING	ST. LOUIS	OPERATIONAL	OFFICE BUILDING	592	GAS ENGINE	2@ 550 kW	7.3	2@ 200 hp.	0.7	3.0	12	
PARK CITY SHOPPING CENTER	LANCASTER PA.	OPERATIONAL GRID CON- NECTED	SHOPPING CENTER	1230	DUAL FUEL IC ENGINE	800 kW 5@ 2200 kW 1@ 1250 kW 1@ 968 kW (2200 kW) to utility	INTERNAL 10.7 TOTAL (12.5)	700 hp.	0.6	3.9	12	
SHER-DEN MALL	SHERMAN TEXAS	OPERATIONAL	SHOPPING CENTER	383	DUAL FUEL IC ENGINE	4@ 1250 kW	13.1	400 hp.	1.0	4.6	12	
CLARK UNIVERSITY	WORCESTER MASS.	GRID CONNECTED	COLLEGE	1080	DIESEL ENGINE	3@ 700 kW	INTERNAL 1.9	3 EXIST	?	?	4	
RICHMOND COLLEGE	NEW YORK	GRID CONNECTED	COLLEGE	1900	GAS TURBINES	4@ 800 kW (2500 kW) to utility	INTERNAL 1.7 TOTAL 3.0	?	?	2.4	3	

APPENDIX C. Building and Operating Components and Sizes for Previously Studied ICES (Contd.)

ICES (COMMUNITY) TYPES	LOCATION	SPECIAL NOTES	BUILDING TYPES	SQUARE FT(1000)	PRIME MOVERS		PEAK SUPPLEMENT		COOLING		REFERENCE NUMBER
					TYPE	SIZES	SIZE IN BOILER kw/sq.ft.	SIZE hp/sq.ft.	SIZE tons/sq.ft.		
MIUS LIVE MODEL	CHICAGO		410 GARDEN APTS	489	GAS IC ENGINE	6@ 500 kw	3.9	2@ 300 hp.	0.8	2.0	6
			63 TOWNHOUSE	98							
			212 RM. MOTEL	91							
			COMMERCIAL BLDG.	16							
			OFFICE BLDG.	75							
TOTAL	769										
HUD MIUS DEMONSTRATION	JERSEY CITY		486 HIGH RISE APTS. ELEMENTARY SCHOOL COMMERCIAL BLDGS	?	DIESEL ENGINE	5@ 600 kw	? ?	2@ 400 hp.	? ?	? ?	13
ROCHDALE VILLAGE	NEW YORK	OPERTIONAL	5860 APARTMENTS SHOPPING CENTER COMMUNITY CENTER TOTAL	7000 300 90 7400	DUAL FUEL IC ENGINES EXTRATION TURBINE	TOTAL 18 MW	2.6	NONE	0	1.7	2
FOX VALLEY	CHICAGO	INSULATION SUBSTANDARD	3226 DWELLING UNITS OFFICES & COMM- ERCIAL VILLAGE CENTER OTHER TOTAL	4871 1200 1709 519 8299	DIESEL ENGINES OR COAL EXTRAC- TION TURBINE	12@ 5 MW 60 MW	7.3	NONE	0	3.3	7
NASA-MIUS NEIGHBORHOOD MIUS	WASHINGTON D. C.	ALL ELECTRIC DISTRICT HEAT/COOL " GRID CONNECTED	713 SINGLE FAMILY 648 MULTI- FAMILY ELEMENTARY SCHOOL TOTAL	1070 723 22 1815	DIESEL ENGINE #2 FUEL	4.8@ 750 kw (ave. of 5 & 4 unit systems)	4.6	250 hp.	0.2	0.9	5

APPENDIX C. Building and Operating Components and Sizes for Previously Studied ICES (Contd.)

NASA-MIUS VILLAGE CENTER	WASHINGTON D. C.		HIGH SCHOOL MIDDLE SCHOOL COMMERCIAL CENTER W SUPPER MARKET 600 MID-RISE APARTMENTS 2 OFFICE BUILDINGS RECREATION BUILDING OTHER NON PEAK TOTAL	79 69 60 865 480 24 - 1577	DIESEL ENGINE NO. 2 FUEL	4@ 1750 kW	4.4	INCINERATOR 4@ 30001b/hr.	9.2	3.6	5
NASA-MIUS VILLAGE COMPLEX MIUS	WASHINGTON D. C.	ALL ELECTRIC DISTRICT HEAT/COOL " " " " " " GRID CONNECTED	2139 SINGLE FAMILY 1944 MULTI- 3 ELEMENTARY SCH. HIGH SCHOOL MIDDLE SCHOOL COMMERCIAL CENTER W SUPERMARKET 600 MID-RISE APTS. 2 OFFICE BLDGS RECREATION BLDG TOTAL	3210 2169 66 79 69 60 865 480 24 7022	DIESEL ENGINE NO. 2 FUEL	8@ 4415 kW	5.0	INCINERATOR 4@ 30001b/hr.	2.1	1.4	5
NASA-MIUS CENTRAL BUSINESS	WASHINGTON D. C.	GRID CONNECTED	8 OFFICE BLDGS. REGIONAL SHOPPING CENTER 4 HIGH RISE APTS. INN/HOTEL HOSPITAL COMMUNITY COLLEGE OTHER HIGH PEAK TOTAL	1920 2146 1153 177 109 64 - 5569	DIESEL ENGINE NO. 2 FUEL	10@ 4415 kW	7.9	INCINERATOR 7@ 30001b/hr.	4.6	3.2	5

APPENDIX D

Distribution of Prime Mover Utilization
by Megawatt Capacity

Number of Plants Within Designated Megawatt Ranges in Existence in 1974

Region State	Fossil						Combustion		Diesel		Combined	
	Coal		Oil		Gas		Turbine				Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
Region I												
Connecticut	1	0	2	0	0	0	8	1	1	0	0	0
Maine	0	0	1	1	0	0	1	1	4	0	0	0
Massachusetts	0	0	7	3	0	0	6	2	7	0	0	0
New Hampshire	0	0	2	0	0	0	2	1	0	0	0	0
Rhode Island	0	0	2	0	0	0	0	0	2	0	0	0
Vermont	1	0	1	0	0	0	4	0	7	0	0	0
Total	2	0	15	4	0	0	21	5	21	0	0	0
Region II												
New Jersey	0	0	0	0	0	0	4	5	1	0	1	0
New York	0	3	0	0	1	0	10	1	5	0	0	0
Puerto Rico	-	-	-	-	Not Available		-	-	-	-	-	-
Virgin Islands	-	-	-	-	Not Available		-	-	-	-	-	-
Total	0	3	0	0	1	0	14	6	6	0	1	0
Region III												
Delaware	0	0	1	0	0	0	3	1	0	0	0	0
Dist. of Columbia	0	0	0	0	0	0	0	0	0	0	0	0
Maryland	0	0	0	0	0	0	0	1	2	0	0	0
Pennsylvania	2	2	1	1	0	0	11	9	1	0	0	0
Virginia	0	0	1	2	0	0	1	2	3	0	0	0
West Virginia	0	0	0	0	0	0	0	0	0	0	0	0
Total	2	2	3	3	0	0	15	13	6	0	0	0

Number of Plants Within Designated Megawatt Ranges in Existence in 1974 (Contd.)

Region State	Fossil						Combustion		Diesel		Combined	
	Coal		Oil		Gas		Turbine				Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region IV</u>												
Alabama	0	1	0	0	1	0	2	0	0	0	0	0
Florida	0	1	0	3	1	0	2	0	0	0	0	0
Georgia	1	0	0	1	0	0	1	1	0	0	0	0
Kentucky	2	1	0	0	0	0	2	0	0	0	0	0
Mississippi	0	0	0	0	0	2	2	0	0	0	0	0
North Carolina	0	0	0	0	0	0	0	1	0	0	0	0
South Carolina	0	0	0	1	0	0	5	1	0	0	0	0
Tennessee	0	0	0	0	0	0	0	0	0	0	0	0
Total	3	3	0	5	2	2	14	3	0	0	0	0
<u>Region V</u>												
Illinois	0	0	0	0	0	1	5	1	4	0	0	0
Indiana	2	0	0	0	0	0	1	2	1	0	0	0
Michigan	5	0	0	0	1	0	11	1	2	0	0	0
Minnesota	6	0	0	0	4	0	2	3	22	0	0	0
Ohio	2	1	1	0	0	0	2	0	5	0	0	0
Wisconsin	2	4	1	0	1	0	5	2	9	0	0	0
Total	17	5	2	0	6	1	26	9	43	0	0	0

Number of Plants Within Designated Megawatt Ranges in Existence in 1974 (Contd.)

Region State	Coal		Fossil Oil		Gas		Combustion Turbine		Diesel		Combined Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region VI</u>												
Arkansas	0	0	0	0	2	1	1	1	0	0	0	0
Louisiana	0	0	0	0	2	2	1	0	2	0	1	0
New Mexico	0	0	0	0	6	2	1	0	0	0	0	0
Oklahoma	0	0	0	0	3	4	1	1	5	0	0	0
Texas	0	0	0	0	8	12	1	1	4	0	0	0
Location unknown in Region	0	0	0	0	0	0	3	0	2	0	0	0
Total	0	0	0	0	21	21	8	3	13	0	1	0
<u>Region VII</u>												
Iowa	1	4	0	0	9	0	2	1	38	0	0	0
Kansas	0	0	0	0	9	5	4	2	15	0	0	0
Missouri	1	2	0	1	6	1	7	1	4	0	0	0
Nebraska	0	0	0	0	6	0	0	2	3	0	0	0
Location unknown in Region	0	0	0	0	0	0	0	0	1	0	0	0
Total	2	6	0	1	30	6	13	6	61	0	0	0

Number of Plants Within Designated Megawatt Ranges in Existence in 1974 (Contd.)

Region State	Coal		Fossil Oil		Gas		Combustion Turbine		Diesel		Combined Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region VIII</u>												
Colorado	4	1	0	0	3	1	2	1	4	0	0	0
Montana	0	1	0	1	1	0	2	0	1	0	0	0
North Dakota	8	0	0	0	0	0	1	0	7	0	0	0
South Dakota	3	0	0	0	3	1	1	0	12	0	0	0
Utah	1	1	1	1	1	0	1	0	3	0	0	0
Wyoming	2	0	1	0	1	0	0	0	3	0	0	0
Total	18	3	2	2	9	2	7	1	30	0	0	0
<u>Region IX</u>												
American Samoa	-	-	-	-	Not Available		-	-	-	-	-	-
Arizona	0	0	1	0	0	1	1	0	1	0	0	0
California	0	0	2	5	0	0	7	2	3	0	0	0
Guam	-	-	-	-	Not Available		-	-	-	-	-	-
Hawaii	-	-	-	-	Not Available		-	-	-	-	-	-
Nevada	0	0	0	0	0	0	2	0	7	0	0	0
Total	0	0	3	5	0	1	10	2	11	0	0	0

Number of Plants Within Designated Megawatt Ranges in Existence in 1974 (Contd.)

Region State	Coal		Fossil Oil		Gas		Combustion Turbine		Diesel		Combined Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region X</u>												
Alaska	-	-	-	-	Not Available		-	-	-	-	-	-
Idaho	0	0	0	0	0	0	1	0	2	0	0	0
Oregon	0	0	1	0	1	1	0	0	1	0	0	0
Washington	0	0	2	2	0	0	2	1	1	0	0	0
Total	0	0	3	2	1	1	3	1	4	0	0	0
NATIONAL TOTAL	44	22	28	22	70	34	131	49	195	0	2	0

Number of Plants Within Designated Megawatt Ranges Planned to be Operating by 1984

Region State	Fossil						Combustion				Combined	
	Coal		Oil		Gas		Turbine		Diesel		Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region I</u>												
Connecticut	0	1	2	0	0	0	8	1	1	0	0	0
Maine	0	0	1	1	0	0	1	1	4	0	0	0
Massachusetts	0	0	5	0	0	0	5	4	8	0	0	0
New Hampshire	0	0	2	0	0	0	2	1	0	0	0	0
Rhode Island	0	0	1	0	0	0	0	0	3	0	0	0
Vermont	1	0	0	0	0	0	4	0	7	0	0	0
Total	1	1	11	1	0	0	20	7	23	0	0	0
<u>Region II</u>												
New Jersey	0	0	0	0	0	0	3	5	1	0	1	0
New York	1	2	0	0	1	0	10	1	5	0	0	0
Puerto Rico	-	-	-	-	Not Available		-	-	-	-	-	-
Virgin Islands	-	-	-	-	Not Available		-	-	-	-	-	-
Total	1	2	0	0	1	0	13	6	6	0	1	0
<u>Region III</u>												
Delaware	0	0	0	0	0	0	3	1	0	0	0	0
Dist. of Columbia	0	0	0	0	0	0	0	0	0	0	0	0
Maryland	0	1	0	0	0	0	0	1	2	0	0	0
Pennsylvania	2	1	0	0	0	0	11	10	1	0	0	0
Virginia	0	0	0	0	0	0	1	2	3	0	0	0
West Virginia	0	0	0	0	0	0	0	0	0	0	0	0
Total	2	2	0	0	0	0	15	14	6	0	0	0

Number of Plants Within Designated Megawatt Ranges Planned to be Operating by 1984 (Contd.)

Region State	Fossil						Combustion				Combined	
	Coal		Oil		Gas		Turbine		Diesel		Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region IV</u>												
Alabama	0	0	0	0	1	0	2	0	0	0	0	0
Florida	0	1	0	0	0	0	2	0	0	0	0	0
Georgia	1	0	0	1	0	0	1	0	0	0	0	0
Kentucky	2	0	0	0	0	0	3	0	0	0	0	0
Mississippi	0	0	0	0	0	2	2	0	0	0	0	0
North Carolina	0	0	0	0	0	0	0	1	0	0	0	0
South Carolina	0	0	0	1	0	0	5	1	0	0	0	0
Tennessee	0	0	0	0	0	0	0	0	0	0	0	0
Total	3	1	0	2	1	2	15	2	0	0	0	0
<u>Region V</u>												
Illinois	0	0	0	0	0	0	6	1	4	0	0	0
Indiana	2	0	0	0	0	0	1	2	1	0	0	0
Michigan	4	1	0	0	1	0	11	2	2	0	0	0
Minnesota	4	0	0	0	2	0	3	3	22	0	0	0
Ohio	1	0	1	0	0	0	2	0	4	0	0	0
Wisconsin	1	4	1	0	1	0	6	2	9	0	0	0
Total	12	5	2	0	4	0	29	10	42	0	0	0

D.7

Number of Plants Within Designated Megawatt Ranges Planned to be Operating by 1984 (Contd.)

Region State	Fossil						Combustion				Combined	
	Coal		Oil		Gas		Turbine		Diesel		Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
Region VI												
Arkansas	0	0	0	0	2	1	1	1	0	0	0	0
Louisiana	0	0	0	0	4	0	1	0	2	0	0	0
New Mexico	0	0	0	0	6	2	1	0	0	0	0	0
Oklahoma	0	0	0	0	2	3	1	2	5	0	0	0
Texas	0	0	0	0	6	16	0	3	4	0	1	0
Location unknown in region	0	0	0	0	0	0	3	0	2	0	0	0
Total	0	0	0	0	20	22	7	6	13	0	1	0
Region VII												
Iowa	1	4	0	0	4	1	2	2	32	0	0	0
Kansas	0	0	0	0	8	3	5	3	15	0	0	0
Missouri	2	1	0	1	4	1	7	2	3	0	0	0
Nebraska	0	0	0	0	3	0	0	2	3	0	0	0
Location unknown in region	0	0	0	0	0	0	0	0	1	0	0	0
Total	3	5	0	1	19	5	14	9	54	0	0	0

Number of Plants Within Designated Megawatt Ranges Planned to be Operating by 1984 (Contd.)

Region State	Fossil						Combustion				Combined	
	Coal		Oil		Gas		Turbine		Diesel		Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region VIII</u>												
Colorado	3	1	0	0	3	1	2	1	4	0	0	0
Montana	1	0	0	1	1	0	2	1	0	0	0	0
North Dakota	3	1	0	0	0	0	1	1	7	0	0	0
South Dakota	2	0	0	0	0	1	3	0	13	0	0	0
Utah	1	1	1	1	1	0	1	0	3	0	0	0
Wyoming	2	0	1	0	1	0	0	0	3	0	0	0
Total	12	3	2	2	6	2	9	3	30	0	0	0
<u>Region IX</u>												
American Samoa	-	-	-	-	Not Available		-	-	-	-	-	-
Arizona	0	0	1	0	0	1	1	0	1	0	0	0
California	0	0	2	3	0	0	10	3	3	0	0	0
Guam	-	-	-	-	Not Available		-	-	-	-	-	-
Hawaii	-	-	-	-	Not Available		-	-	-	-	-	-
Nevada	0	0	0	0	0	0	2	0	7	0	0	0
Total	0	0	3	3	0	1	13	3	11	0	0	0

Number of Plants Within Designated Megawatt Ranges Planned to be Operating by 1984 (Contd.)

Region	Fossil						Combustion		Diesel		Combined	
	Coal		Oil		Gas		Turbine				Cycle	
	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100	1-50	51-100
<u>Region X</u>												
Alaska	-	-	-	-	Not Available		-	-	-	-	-	-
Idaho	0	0	0	0	0	0	1	0	2	0	0	0
Oregon	0	0	1	0	1	1	0	0	1	0	0	0
Washington	0	0	2	2	0	0	2	1	1	0	0	0
Total	0	0	3	2	1	1	3	1	4	0	0	0
NATIONAL TOTAL	34	19	21	11	52	33	138	61	189	0	2	0

D.10

NATIONAL SUMMARY

TOTAL MW EXISTING AND PLANNED

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR			
1974	173589.38	82655.94	61843.78	30174.00	38883.57	1513.80	1780.00	58782.58	8683.20	396.00	2205.50	
1975	10623.80	6050.80	3084.50	8520.00	3762.00	-1.80	510.00	2150.00	555.00	106.00	76.30	
1976	9181.00	3912.00	1454.20	8489.00	965.00	1.30	1581.00	1695.00	200.00	0.0	-29.00	
1977	13033.00	4540.00	1072.00	9063.00	684.00	0.0	1170.00	2159.00	540.00	271.00	20.00	
1978	10508.00	2402.00	1150.00	7385.00	1567.00	8.00	236.00	2590.00	2396.00	135.00	746.00	
1979	19797.00	1714.00	317.50	7399.00	2818.00	19.00	320.00	1133.00	50.00	110.00	310.00	
1980	16019.00	2212.00	707.00	16277.00	2038.00	-15.00	1662.00	685.00	1085.00	110.00	1794.00	
1981	14560.50	922.30	-5.70	19193.00	738.00	4.80	350.00	614.00	3525.00	110.00	3639.00	
1982	14603.00	143.00	-313.00	25963.00	793.00	0.80	770.00	631.00	5350.00	110.00	6658.00	
1983	12873.00	136.00	-136.00	23796.00	999.00	3.00	450.00	443.00	1050.00	110.00	5417.00	
1984	7960.00	-98.00	520.00	28292.00	1267.00	0.0	452.00	378.00	1250.00	110.00	6272.00	

MW ADDED TO OR RETIRED FROM EXISTING SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR			
1974	173589.38	82655.94	61843.78	30174.00	38883.57	1513.80	1780.00	58782.58	8683.20	396.00	2205.50	
1975	6994.80	4855.80	981.50	1919.00	3148.00	-1.80	510.00	0.0	0.0	106.00	154.00	
1976	4171.00	3087.00	1532.20	4536.00	621.00	-3.70	1335.00	0.0	0.0	0.0	-6.00	
1977	6527.00	2045.00	972.00	1236.00	5.00	0.0	1130.00	0.0	0.0	271.00	0.0	
1978	3198.00	1402.00	1150.00	2107.00	438.00	3.00	236.00	0.0	0.0	135.00	590.00	
1979	4296.00	389.00	317.50	3434.00	328.00	13.00	50.00	0.0	0.0	110.00	430.00	
1980	1438.00	1602.00	707.00	1443.00	70.00	-15.00	360.00	0.0	0.0	110.00	526.00	
1981	2435.50	-302.70	-205.70	3415.00	60.00	-0.20	0.0	0.0	0.0	110.00	26.00	
1982	1283.00	-467.00	-313.00	2280.00	90.00	0.80	50.00	0.0	0.0	110.00	0.0	
1983	402.00	136.00	-101.00	2050.00	-1.00	3.00	0.0	0.0	0.0	110.00	420.00	
1984	1744.00	-98.00	520.00	900.00	60.00	0.0	0.0	-12.00	0.0	110.00	0.0	

MW ADDED AT NEW SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR			
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
1975	3629.00	1195.00	2103.00	6601.00	614.00	0.0	0.0	2150.00	555.00	0.0	-77.70	
1976	5010.00	825.00	-78.00	3953.00	344.00	5.00	246.00	1695.00	200.00	0.0	-23.00	
1977	6506.00	2495.00	100.00	7827.00	679.00	0.0	40.00	2159.00	540.00	0.0	20.00	
1978	7710.00	1000.00	0.0	5278.00	1129.00	5.00	0.0	2590.00	2396.00	0.0	156.00	
1979	15501.00	1325.00	0.0	3965.00	2490.00	6.00	270.00	1133.00	50.00	0.0	-120.00	
1980	14581.00	610.00	0.0	14834.00	1968.00	0.0	1302.00	685.00	1085.00	0.0	1268.00	
1981	12125.00	1225.00	200.00	15778.00	678.00	5.00	350.00	614.00	3525.00	0.0	3613.00	
1982	13320.00	610.00	0.0	23683.00	703.00	0.0	720.00	631.00	5350.00	0.0	6658.00	
1983	12471.00	0.0	-35.00	21746.00	1000.00	0.0	450.00	443.00	1050.00	0.0	4997.00	
1984	6216.00	0.0	0.0	27392.00	1207.00	0.0	452.00	390.00	1250.00	0.0	6272.00	

REGION 1

TOTAL MW EXISTING AND PLANNED

	FOSSIL				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM	OTHER
1974	1165.00	10829.70	0.0	3316.00	1477.70	219.60	0.0	1294.20	1642.20	0.0	0.0
1975	0.0	1445.50	0.0	906.00	0.0	0.0	110.00	0.0	0.0	0.0	0.0
1976	9.00	10.00	0.0	303.00	0.0	7.00	95.00	0.0	0.0	0.0	0.0
1977	0.0	-4.00	0.0	0.0	20.00	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	600.00	0.0	0.0	120.00	8.00	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	1150.00	0.0	9.00	270.00	0.0	0.0	0.0	0.0
1980	0.0	880.00	0.0	1150.00	110.00	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	376.30	0.0	0.0	0.0	2.00	0.0	0.0	0.0	0.0	0.0
1982	0.0	-53.00	0.0	2330.00	0.0	3.00	0.0	0.0	0.0	0.0	26.00
1983	0.0	696.00	0.0	2300.00	0.0	3.00	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED TO OR RETIRED FROM EXISTING SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM	OTHER
1974	1165.00	10829.70	0.0	3316.00	1477.70	219.60	0.0	1294.20	1642.20	0.0	0.0
1975	0.0	1000.50	0.0	906.00	0.0	0.0	110.00	0.0	0.0	0.0	0.0
1976	9.00	10.00	0.0	303.00	0.0	2.00	95.00	0.0	0.0	0.0	0.0
1977	0.0	-4.00	0.0	0.0	20.00	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	600.00	0.0	0.0	0.0	3.00	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	1150.00	0.0	3.00	0.0	0.0	0.0	0.0	0.0
1980	0.0	880.00	0.0	0.0	110.00	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	-23.70	0.0	0.0	0.0	2.00	0.0	0.0	0.0	0.0	0.0
1982	0.0	-53.00	0.0	1180.00	0.0	3.00	0.0	0.0	0.0	0.0	0.0
1983	0.0	696.00	0.0	0.0	0.0	3.00	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED AT NEW SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM	OTHER
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	445.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	5.00	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	120.00	5.00	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	6.00	270.00	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	1150.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	400.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	1150.00	0.0	0.0	0.0	0.0	0.0	0.0	26.00
1983	0.0	0.0	0.0	2300.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

REGION 2

TOTAL MW EXISTING AND PLANNED

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STP	GEOTHERM	
1974	4190.00	17722.00	3.00	2603.00	9697.00	76.00	17.00	4018.40	1330.00	0.0	0.0
1975	0.0	658.00	0.0	821.00	377.00	0.0	1.00	0.0	0.0	0.0	0.0
1976	0.0	860.00	0.0	1963.00	0.0	0.0	126.00	0.0	0.0	0.0	0.0
1977	0.0	223.00	0.0	262.00	0.0	0.0	0.0	0.0	0.0	0.0	32.00
1978	-18.00	850.00	0.0	912.00	120.00	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	1115.00	60.00	0.0	0.0	0.0	0.0	0.0	0.0
1980	1550.00	0.0	0.0	228.00	106.00	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	1100.00	120.00	0.0	0.0	0.0	1000.00	0.0	0.0
1982	0.0	0.0	0.0	3418.00	180.00	0.0	0.0	0.0	0.0	0.0	0.0
1983	-15.00	-342.00	0.0	1200.00	180.00	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	-238.00	0.0	4600.00	0.0	0.0	0.0	0.0	0.0	0.0	300.00

MW ADDED TO OR RETIRED FROM EXISTING SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM	
1974	4190.00	17722.00	3.00	2603.00	9697.00	76.00	17.00	4018.40	1330.00	0.0	0.0
1975	0.0	658.00	0.0	0.0	377.00	0.0	1.00	0.0	0.0	0.0	0.0
1976	0.0	860.00	0.0	1963.00	0.0	0.0	126.00	0.0	0.0	0.0	0.0
1977	0.0	223.00	0.0	262.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	-18.00	850.00	0.0	92.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	1115.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	228.00	-14.00	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	1100.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1983	-15.00	-342.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	-238.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED AT NEW SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM	
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	821.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.00
1978	0.0	0.0	0.0	820.00	120.00	0.0	0.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	60.00	0.0	0.0	0.0	0.0	0.0	0.0
1980	1550.00	0.0	0.0	0.0	120.00	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	120.00	0.0	0.0	0.0	1000.00	0.0	0.0
1982	0.0	0.0	0.0	3418.00	180.00	0.0	0.0	0.0	0.0	0.0	0.0
1983	0.0	0.0	0.0	1200.00	180.00	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	4600.00	0.0	0.0	0.0	0.0	0.0	0.0	300.00

REGION 3

TOTAL MW EXISTING AND PLANNED

	FOSSIL				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM	
1974	31339.30	11192.80	0.0	4614.00	5484.20	144.70	333.00	2079.00	1781.00	0.0	120.50
1975	662.00	2091.30	0.0	1606.00	0.0	0.0	0.0	0.0	0.0	0.0	-69.00
1976	0.0	456.00	0.0	60.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	1475.00	800.00	0.0	2782.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	906.00	0.0	0.0	0.0	0.0	100.00	0.0	0.0
1979	3067.00	-208.00	0.0	0.0	250.00	12.00	0.0	0.0	0.0	0.0	0.0
1980	626.00	1240.00	0.0	1988.00	0.0	0.0	0.0	0.0	0.0	0.0	26.00
1981	0.0	-167.00	0.0	3619.00	100.00	0.0	0.0	0.0	500.00	0.0	26.00
1982	800.00	347.00	0.0	1050.00	0.0	0.0	0.0	0.0	1550.00	0.0	0.0
1983	377.00	-136.00	0.0	1984.00	300.00	0.0	0.0	0.0	1050.00	0.0	0.0
1984	1292.00	0.0	0.0	2830.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED TO OR RETIRED FROM EXISTING SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM	
1974	31339.30	11192.80	0.0	4614.00	5484.20	144.70	333.00	2079.00	1781.00	0.0	120.50
1975	-163.00	2091.30	0.0	-130.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	456.00	0.0	60.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	650.00	800.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	906.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	316.00	-208.00	0.0	0.0	0.0	12.00	0.0	0.0	0.0	0.0	0.0
1980	0.0	630.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.00
1981	0.0	-167.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.00
1982	800.00	-263.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1983	-249.00	-136.00	0.0	900.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	666.00	0.0	0.0	900.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED AT NEW SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM	
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	825.00	0.0	0.0	1736.00	0.0	0.0	0.0	0.0	0.0	0.0	-69.00
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	825.00	0.0	0.0	2782.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.00	0.0	0.0
1979	2751.00	0.0	0.0	0.0	250.00	0.0	0.0	0.0	0.0	0.0	0.0
1980	626.00	610.00	0.0	1988.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	3619.00	100.00	0.0	0.0	0.0	500.00	0.0	0.0
1982	0.0	610.00	0.0	1050.00	0.0	0.0	0.0	0.0	1550.00	0.0	0.0
1983	626.00	0.0	0.0	1084.00	300.00	0.0	0.0	0.0	1050.00	0.0	0.0
1984	626.00	0.0	0.0	1930.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0

REGION 4

TOTAL MW EXISTING AND PLANNED

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO			
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM	OTHER	
1974	51052.89	12840.50	2034.90	6605.00	7465.19	61.00	135.00	8813.10	305.00	0.0	1923.00	
1975	2192.00	1067.00	0.0	1886.00	1744.00	0.0	0.0	391.00	555.00	0.0	74.00	
1976	1612.00	1317.00	-47.00	3587.00	150.00	0.0	552.00	60.00	0.0	0.0	-2.00	
1977	1527.00	2314.00	0.0	3945.00	65.00	0.0	0.0	0.0	240.00	0.0	-2.00	
1978	1736.00	-20.00	0.0	3149.00	253.00	0.0	0.0	0.0	1865.00	0.0	408.00	
1979	2492.00	1310.00	0.0	3249.00	430.00	0.0	0.0	117.00	0.0	0.0	336.00	
1980	3454.00	600.00	0.0	5736.00	430.00	-15.00	0.0	180.00	675.00	0.0	990.00	
1981	4125.00	1060.00	0.0	5991.00	0.0	0.0	350.00	122.00	0.0	0.0	2595.00	
1982	2702.00	0.0	0.0	5608.00	150.00	0.0	720.00	300.00	1200.00	0.0	3838.00	
1983	1046.00	0.0	0.0	7262.00	50.00	0.0	450.00	0.0	0.0	0.0	3875.00	
1984	0.0	342.00	0.0	9562.00	65.00	0.0	0.0	0.0	750.00	0.0	3772.00	

MW ADDED TO OR RETIRED FROM EXISTING SITES

	-----FOSSIL-----			COMBUSTION		COMBINED		HYDRO		GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR		
1974	51052.89	12840.50	2034.90	6605.00	7465.19	61.00	135.00	8813.10	305.00	0.0	1923.00
1975	1912.00	317.00	0.0	1065.00	1594.00	0.0	0.0	0.0	0.0	0.0	142.00
1976	416.00	492.00	-47.00	1890.00	0.0	0.0	552.00	0.0	0.0	0.0	0.0
1977	1067.00	819.00	0.0	0.0	65.00	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	-20.00	0.0	1969.00	253.00	0.0	0.0	0.0	0.0	0.0	410.00
1979	436.00	485.00	0.0	1169.00	0.0	0.0	0.0	0.0	0.0	0.0	410.00
1980	0.0	600.00	0.0	1215.00	0.0	-15.00	0.0	0.0	0.0	0.0	0.0
1981	1000.00	235.00	0.0	1215.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	0.0	150.00	0.0	0.0	0.0	0.0	0.0	0.0
1983	-139.00	0.0	0.0	0.0	50.00	0.0	0.0	0.0	0.0	0.0	420.00
1984	0.0	342.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED AT NEW SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO		
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM	OTHER
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	280.00	750.00	0.0	821.00	150.00	0.0	0.0	391.00	555.00	0.0	-68.00
1976	1196.00	825.00	0.0	1697.00	150.00	0.0	0.0	60.00	0.0	0.0	-2.00
1977	460.00	1495.00	0.0	3945.00	0.0	0.0	0.0	0.0	240.00	0.0	-2.00
1978	1736.00	0.0	0.0	1180.00	0.0	0.0	0.0	0.0	1865.00	0.0	-2.00
1979	2056.00	825.00	0.0	2080.00	430.00	0.0	0.0	117.00	0.0	0.0	-74.00
1980	3454.00	0.0	0.0	4521.00	430.00	0.0	0.0	180.00	675.00	0.0	990.00
1981	3125.00	825.00	0.0	4776.00	0.0	0.0	350.00	122.00	0.0	0.0	2595.00
1982	2702.00	0.0	0.0	5608.00	0.0	0.0	720.00	300.00	1200.00	0.0	3838.00
1983	1185.00	0.0	0.0	7262.00	0.0	0.0	450.00	0.0	0.0	0.0	3455.00
1984	0.0	0.0	0.0	9562.00	65.00	0.0	0.0	0.0	750.00	0.0	3772.00

REGION 5

TOTAL MW EXISTING AND PLANNED

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR	GEO THERM		
1974	60387.80	5648.00	1047.50	9169.00	7725.00	338.50	0.0	798.20	1951.00	0.0		100.00
1975	4484.00	789.00	-121.00	850.00	101.00	0.0	96.00	0.0	0.0	0.0		57.60
1976	3147.00	689.00	-53.00	1476.00	50.00	-2.00	0.0	31.00	0.0	0.0		0.0
1977	3159.00	936.00	0.0	0.0	0.0	0.0	0.0	40.00	0.0	0.0		0.0
1978	3113.00	1000.00	-40.00	2178.00	213.00	0.0	0.0	0.0	0.0	0.0		0.0
1979	3139.00	500.00	-228.00	1885.00	227.00	0.0	0.0	0.0	0.0	0.0		20.00
1980	1219.00	-371.00	0.0	2325.00	60.00	0.0	0.0	0.0	0.0	0.0		500.00
1981	2995.00	-4.00	0.0	2888.00	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1982	1864.00	-27.00	-313.00	3927.00	0.0	0.0	0.0	0.0	0.0	0.0		550.00
1983	1686.00	-82.00	0.0	2936.00	50.00	0.0	0.0	0.0	0.0	0.0		542.00
1984	1806.00	0.0	0.0	6430.00	60.00	0.0	0.0	0.0	0.0	0.0		1100.00

MW ADDED TO OR RETIRED FROM EXISTING SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR	GEO THERM		
1974	60387.80	5648.00	1047.50	9169.00	7725.00	338.50	0.0	798.20	1951.00	0.0		100.00
1975	3307.00	789.00	-121.00	0.0	57.00	0.0	96.00	0.0	0.0	0.0		12.00
1976	930.00	689.00	-53.00	320.00	20.00	-2.00	0.0	0.0	0.0	0.0		0.0
1977	629.00	-64.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1978	1856.00	0.0	-40.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1979	-69.00	0.0	-228.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		20.00
1980	559.00	-371.00	0.0	0.0	60.00	0.0	0.0	0.0	0.0	0.0		500.00
1981	1445.00	-4.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1982	484.00	-27.00	-313.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1983	456.00	-82.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1984	-224.00	0.0	0.0	0.0	60.00	0.0	0.0	0.0	0.0	0.0		0.0

MW ADDED AT NEW SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR	GEO THERM		
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1975	1177.00	0.0	0.0	850.00	44.00	0.0	0.0	0.0	0.0	0.0		45.60
1976	2217.00	0.0	0.0	1156.00	30.00	0.0	0.0	31.00	0.0	0.0		0.0
1977	2530.00	1000.00	0.0	0.0	0.0	0.0	0.0	40.00	0.0	0.0		0.0
1978	1257.00	1000.00	0.0	2178.00	213.00	0.0	0.0	0.0	0.0	0.0		0.0
1979	3208.00	500.00	0.0	1885.00	227.00	0.0	0.0	0.0	0.0	0.0		0.0
1980	660.00	0.0	0.0	2325.00	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1981	1550.00	0.0	0.0	2888.00	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1982	1380.00	0.0	0.0	3927.00	0.0	0.0	0.0	0.0	0.0	0.0		550.00
1983	1230.00	0.0	0.0	2936.00	50.00	0.0	0.0	0.0	0.0	0.0		542.00
1984	2030.00	0.0	0.0	6430.00	0.0	0.0	0.0	0.0	0.0	0.0		1100.00

REGION 6

TOTAL MW EXISTING AND PLANNED

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM		
1974	3973.00	1685.00	50351.50	830.00	1269.80	135.50	921.00	2026.60	28.00	0.0		28.00
1975	830.00	0.0	3251.50	0.0	492.00	0.0	230.00	0.0	0.0	0.0		-73.30
1976	1393.00	580.00	1502.00	0.0	200.00	3.00	0.0	0.0	0.0	0.0		-27.00
1977	3347.00	0.0	1208.00	950.00	677.00	0.0	270.00	0.0	0.0	0.0		-10.00
1978	2877.00	0.0	1190.00	0.0	80.00	0.0	0.0	0.0	0.0	0.0		-42.00
1979	5125.00	0.0	671.00	0.0	399.00	0.0	0.0	32.00	0.0	0.0		-46.00
1980	3942.00	0.0	760.00	3600.00	677.00	0.0	230.00	0.0	0.0	0.0		200.00
1981	4175.00	0.0	133.00	2105.00	204.00	0.0	0.0	0.0	0.0	0.0		60.00
1982	5583.00	0.0	0.0	3600.00	200.00	0.0	0.0	0.0	0.0	0.0		590.00
1983	5680.00	0.0	-136.00	1986.00	-6.00	0.0	0.0	0.0	0.0	0.0		250.00
1984	2815.00	0.0	520.00	300.00	989.00	0.0	0.0	0.0	0.0	0.0		200.00

MW ADDED TO OR RETIRED FROM EXISTING SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM		
1974	3973.00	1685.00	50351.50	830.00	1269.80	135.50	921.00	2026.60	28.00	0.0		28.00
1975	830.00	0.0	1148.50	0.0	492.00	0.0	230.00	0.0	0.0	0.0		0.0
1976	326.00	580.00	1580.00	0.0	200.00	3.00	0.0	0.0	0.0	0.0		-6.00
1977	1233.00	0.0	1108.00	950.00	360.00	0.0	230.00	0.0	0.0	0.0		0.0
1978	981.00	0.0	1190.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1979	990.00	0.0	671.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1980	916.00	0.0	760.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1981	0.0	0.0	-67.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1983	0.0	0.0	-101.00	0.0	-6.00	0.0	0.0	0.0	0.0	0.0		0.0
1984	615.00	0.0	520.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

MW ADDED AT NEW SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEO THERM		
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1975	0.0	0.0	2103.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		-73.30
1976	1067.00	0.0	-78.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		-21.00
1977	2114.00	0.0	100.00	0.0	317.00	0.0	40.00	0.0	0.0	0.0		-10.00
1978	1896.00	0.0	0.0	0.0	80.00	0.0	0.0	0.0	0.0	0.0		-42.00
1979	4135.00	0.0	0.0	0.0	399.00	0.0	0.0	32.00	0.0	0.0		-46.00
1980	3026.00	0.0	0.0	3600.00	677.00	0.0	230.00	0.0	0.0	0.0		200.00
1981	4175.00	0.0	200.00	2105.00	204.00	0.0	0.0	0.0	0.0	0.0		60.00
1982	5583.00	0.0	0.0	3600.00	200.00	0.0	0.0	0.0	0.0	0.0		590.00
1983	5680.00	0.0	-35.00	1986.00	0.0	0.0	0.0	0.0	0.0	0.0		250.00
1984	2200.00	0.0	0.0	300.00	989.00	0.0	0.0	0.0	0.0	0.0		200.00

REGION 7

TOTAL MW EXISTING AND PLANNED

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR			
1974	11344.10	70.00	5780.59	1684.00	1983.50	231.20	70.00	724.10	300.00	0.0	0.0	0.0
1975	558.60	0.0	-55.00	78.00	420.00	-8.10	0.0	0.0	0.0	0.0	0.0	87.00
1976	733.00	0.0	52.20	0.0	291.00	-5.80	0.0	0.0	0.0	0.0	0.0	0.0
1977	2040.00	0.0	-77.50	24.00	314.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	1234.00	0.0	0.0	0.0	546.00	0.0	0.0	27.00	31.00	0.0	0.0	0.0
1979	2008.00	0.0	-125.50	0.0	909.00	-2.00	0.0	0.0	0.0	0.0	0.0	0.0
1980	1909.00	0.0	-53.00	0.0	500.00	0.0	0.0	0.0	160.00	0.0	0.0	0.0
1981	874.00	0.0	-48.70	1150.00	200.00	2.80	0.0	0.0	400.00	0.0	0.0	0.0
1982	999.00	0.0	0.0	1150.00	23.00	-2.20	0.0	0.0	600.00	0.0	0.0	0.0
1983	349.00	0.0	0.0	2300.00	120.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	979.00	0.0	0.0	1100.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED TO OR RETIRED FROM EXISTING SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR			
1974	11344.10	70.00	5780.59	1684.00	1983.50	231.20	70.00	724.10	300.00	0.0	0.0	0.0
1975	-18.40	0.0	-55.00	78.00	234.00	-8.10	0.0	0.0	0.0	0.0	0.0	0.0
1976	533.00	0.0	52.20	0.0	291.00	-5.80	0.0	0.0	0.0	0.0	0.0	0.0
1977	1463.00	0.0	-77.50	24.00	84.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	-46.00	0.0	0.0	0.0	105.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979	1198.00	0.0	-125.50	0.0	55.00	-2.00	0.0	0.0	0.0	0.0	0.0	0.0
1980	-1.00	0.0	-53.00	0.0	9.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	-1.00	0.0	-48.70	0.0	0.0	-2.20	0.0	0.0	0.0	0.0	0.0	0.0
1982	-1.00	0.0	0.0	0.0	0.0	-2.20	0.0	0.0	0.0	0.0	0.0	0.0
1983	349.00	0.0	0.0	1150.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	299.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED AT NEW SITES

	-----FOSSIL-----				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE		PUMP-STR			
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	577.00	0.0	0.0	0.0	186.00	0.0	0.0	0.0	0.0	0.0	0.0	87.00
1976	200.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	577.00	0.0	0.0	0.0	230.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	1280.00	0.0	0.0	0.0	441.00	0.0	0.0	27.00	31.00	0.0	0.0	0.0
1979	810.00	0.0	0.0	0.0	854.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	1910.00	0.0	0.0	0.0	491.00	0.0	0.0	0.0	160.00	0.0	0.0	0.0
1981	875.00	0.0	0.0	1150.00	200.00	5.00	0.0	0.0	400.00	0.0	0.0	0.0
1982	1000.00	0.0	0.0	1150.00	23.00	0.0	0.0	0.0	600.00	0.0	0.0	0.0
1983	0.0	0.0	0.0	1150.00	120.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	680.00	0.0	0.0	1100.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

REGION 8

TOTAL MW EXISTING AND PLANNED

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM		
1974	6057.40	287.00	451.30	0.0	281.20	174.30	0.0	4785.00	324.00	0.0		0.0
1975	1151.20	0.0	0.0	330.00	202.00	6.30	0.0	242.00	0.0	0.0		0.0
1976	1420.00	0.0	0.0	0.0	30.00	-0.90	0.0	241.00	0.0	0.0		0.0
1977	1323.00	0.0	-58.50	0.0	132.00	0.0	0.0	129.00	100.00	0.0		0.0
1978	1541.00	0.0	0.0	0.0	123.00	0.0	0.0	0.0	0.0	0.0		0.0
1979	3091.00	0.0	0.0	0.0	25.00	0.0	0.0	0.0	0.0	0.0		0.0
1980	1719.00	0.0	0.0	0.0	25.00	0.0	0.0	0.0	100.00	0.0		0.0
1981	2391.50	0.0	-90.00	0.0	0.0	0.0	0.0	131.00	0.0	0.0		750.00
1982	1555.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		750.00
1983	2500.00	0.0	0.0	0.0	0.0	0.0	0.0	143.00	0.0	0.0		750.00
1984	568.00	0.0	0.0	0.0	100.00	0.0	0.0	378.00	0.0	0.0		750.00

MW ADDED TO OR RETIRED FROM EXISTING SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM		
1974	6057.40	287.00	451.30	0.0	281.20	174.30	0.0	4785.00	324.00	0.0		0.0
1975	381.20	0.0	0.0	0.0	0.0	6.30	0.0	0.0	0.0	0.0		0.0
1976	1090.00	0.0	0.0	0.0	30.00	-0.90	0.0	0.0	0.0	0.0		0.0
1977	1323.00	0.0	-58.50	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1978	0.0	0.0	0.0	0.0	55.00	0.0	0.0	0.0	0.0	0.0		0.0
1979	900.00	0.0	0.0	0.0	25.00	0.0	0.0	0.0	0.0	0.0		0.0
1980	-36.00	0.0	0.0	0.0	25.00	0.0	0.0	0.0	0.0	0.0		0.0
1981	-8.50	0.0	-90.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1983	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1984	388.00	0.0	0.0	0.0	0.0	0.0	0.0	-12.00	0.0	0.0		0.0

MW ADDED AT NEW SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO		OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR	GEOTHERM		
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1975	770.00	0.0	0.0	330.00	202.00	0.0	0.0	242.00	0.0	0.0		0.0
1976	330.00	0.0	0.0	0.0	0.0	0.0	0.0	241.00	0.0	0.0		0.0
1977	0.0	0.0	0.0	0.0	132.00	0.0	0.0	129.00	100.00	0.0		0.0
1978	1541.00	0.0	0.0	0.0	68.00	0.0	0.0	0.0	0.0	0.0		0.0
1979	2191.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
1980	1755.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.00	0.0		0.0
1981	2400.00	0.0	0.0	0.0	0.0	0.0	0.0	131.00	0.0	0.0		750.00
1982	1555.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		750.00
1983	2500.00	0.0	0.0	0.0	0.0	0.0	0.0	143.00	0.0	0.0		750.00
1984	180.00	0.0	0.0	0.0	100.00	0.0	0.0	390.00	0.0	0.0		750.00

REGION 9

TOTAL MW EXISTING AND PLANNED

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR			
1974	2680.00	22169.00	2088.00	493.00	2475.00	120.00	304.00	11097.00	922.00		396.00	0.0
1975	746.00	0.0	9.00	913.00	426.00	0.0	73.00	0.0	0.0		106.00	0.0
1976	867.00	0.0	0.0	1100.00	244.00	0.0	808.00	36.00	200.00		0.0	0.0
1977	162.00	271.00	0.0	1100.00	-60.00	0.0	286.00	0.0	200.00		271.00	0.0
1978	425.00	-28.00	0.0	0.0	112.00	0.0	236.00	0.0	400.00		135.00	200.00
1979	875.00	112.00	0.0	0.0	518.00	0.0	50.00	300.00	0.0		110.00	0.0
1980	600.00	-137.00	0.0	0.0	130.00	0.0	1432.00	505.00	0.0		110.00	78.00
1981	0.0	-343.00	0.0	1100.00	114.00	0.0	0.0	0.0	1625.00		110.00	208.00
1982	1100.00	-124.00	0.0	2370.00	240.00	0.0	50.00	20.00	0.0		110.00	904.00
1983	750.00	0.0	0.0	1300.00	305.00	0.0	0.0	300.00	0.0		110.00	0.0
1984	500.00	-202.00	0.0	3470.00	53.00	0.0	452.00	0.0	500.00		110.00	150.00

MW ADDED TO OR RETIRED FROM EXISTING SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR			
1974	2680.00	22169.00	2088.00	493.00	2475.00	120.00	304.00	11097.00	922.00		396.00	0.0
1975	746.00	0.0	9.00	0.0	394.00	0.0	73.00	0.0	0.0		106.00	0.0
1976	867.00	0.0	0.0	0.0	80.00	0.0	562.00	0.0	0.0		0.0	0.0
1977	162.00	271.00	0.0	0.0	-60.00	0.0	286.00	0.0	0.0		271.00	0.0
1978	425.00	-28.00	0.0	0.0	25.00	0.0	236.00	0.0	0.0		135.00	0.0
1979	525.00	112.00	0.0	0.0	248.00	0.0	50.00	0.0	0.0		110.00	0.0
1980	0.0	-137.00	0.0	0.0	-120.00	0.0	360.00	0.0	0.0		110.00	0.0
1981	0.0	-343.00	0.0	1100.00	60.00	0.0	0.0	0.0	0.0		110.00	0.0
1982	0.0	-124.00	0.0	1100.00	-60.00	0.0	50.00	0.0	0.0		110.00	0.0
1983	0.0	0.0	0.0	0.0	-45.00	0.0	0.0	0.0	0.0		110.00	0.0
1984	0.0	-202.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0		110.00	0.0

MW ADDED AT NEW SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO	GEO THERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR			
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
1975	0.0	0.0	0.0	913.00	32.00	0.0	0.0	0.0	0.0		0.0	0.0
1976	0.0	0.0	0.0	1100.00	164.00	0.0	246.00	36.00	200.00		0.0	0.0
1977	0.0	0.0	0.0	1100.00	0.0	0.0	0.0	0.0	200.00		0.0	0.0
1978	0.0	0.0	0.0	0.0	87.00	0.0	0.0	0.0	400.00		0.0	200.00
1979	350.00	0.0	0.0	0.0	270.00	0.0	0.0	300.00	0.0		0.0	0.0
1980	600.00	0.0	0.0	0.0	250.00	0.0	1072.00	505.00	0.0		0.0	78.00
1981	0.0	0.0	0.0	0.0	54.00	0.0	0.0	0.0	1625.00		0.0	208.00
1982	1100.00	0.0	0.0	1270.00	300.00	0.0	0.0	20.00	0.0		0.0	904.00
1983	750.00	0.0	0.0	1300.00	350.00	0.0	0.0	300.00	0.0		0.0	0.0
1984	500.00	0.0	0.0	3470.00	53.00	0.0	452.00	0.0	500.00		0.0	150.00

REGION 10

TOTAL MW EXISTING AND PLANNED

	FOSSIL				COMBUSTION		COMBINED	HYDRO		GEOTHERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR		
1974	1400.00	212.00	87.00	860.00	1025.00	13.00	0.0	23147.00	100.00	0.0	34.00
1975	0.0	0.0	0.0	1130.00	0.0	0.0	0.0	1517.00	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1327.00	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	-464.00	0.0	614.00	1990.00	0.0	0.0	0.0
1978	0.0	0.0	0.0	240.00	0.0	0.0	0.0	2563.00	0.0	0.0	180.00
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	684.00	50.00	0.0	0.0
1980	1000.00	0.0	0.0	1250.00	0.0	0.0	0.0	0.0	150.00	0.0	0.0
1981	0.0	0.0	0.0	1240.00	0.0	0.0	0.0	361.00	0.0	0.0	0.0
1982	0.0	0.0	0.0	2510.00	0.0	0.0	0.0	311.00	2000.00	0.0	0.0
1983	500.00	0.0	0.0	2528.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED TO OR RETIRED FROM EXISTING SITES

	FOSSIL			COMBUSTION		COMBINED		HYDRO		GEOTHERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR		
1974	1400.00	212.00	87.00	860.00	1025.00	13.00	0.0	23147.00	100.00	0.0	34.00
1975	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	-464.00	0.0	614.00	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	-860.00	0.0	0.0	0.0	0.0	0.0	0.0	180.00
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1983	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

MW ADDED AT NEW SITES

	FOSSIL				COMBUSTION		COMBINED		HYDRO	HYDRO	GEOTHERM	OTHER
	COAL	OIL	GAS	NUCLEAR	TURBINE	DIESEL	CYCLE	HYDRO	PUMP-STR			
1974	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1975	0.0	0.0	0.0	1130.00	0.0	0.0	0.0	1517.00	0.0	0.0	0.0	0.0
1976	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1327.00	0.0	0.0	0.0	0.0
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1990.00	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	1100.00	0.0	0.0	0.0	2563.00	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	0.0	0.0	0.0	0.0	684.00	50.00	0.0	0.0	0.0
1980	1000.00	0.0	0.0	1250.00	0.0	0.0	0.0	0.0	150.00	0.0	0.0	0.0
1981	0.0	0.0	0.0	1240.00	0.0	0.0	0.0	361.00	0.0	0.0	0.0	0.0
1982	0.0	0.0	0.0	2510.00	0.0	0.0	0.0	311.00	2000.00	0.0	0.0	0.0
1983	500.00	0.0	0.0	2528.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

DISTRIBUTION OF POWER PLANTS BY MEGAWATT CAPACITY
CCUNTRY 1974

MW	FOSSIL			NUCLEAR	COMBUSTION TURBINE	DIESEL	COMBINED CYCLE	HYDRO	HYDRO PUMP-STR	GEOTHERM	OTHER
	COAL	OIL	GAS								
1 - 10	9.00	3.00	6.00	0.0	11.00	169.00	0.0	2.00	0.0	0.0	2.00
11 - 20	8.00	7.00	23.00	0.0	47.00	17.00	1.00	1.00	0.0	0.0	1.00
21 - 30	12.00	8.00	17.00	0.0	42.00	7.00	0.0	1.00	1.00	0.0	2.00
31 - 40	10.00	5.00	8.00	0.0	16.00	2.00	0.0	0.0	0.0	0.0	2.00
41 - 50	5.00	5.00	16.00	0.0	15.00	0.0	1.00	0.0	1.00	0.0	0.0
51 - 60	3.00	2.00	9.00	0.0	13.00	0.0	0.0	0.0	0.0	0.0	1.00
61 - 70	8.00	8.00	4.00	0.0	10.00	0.0	0.0	1.00	0.0	0.0	0.0
71 - 80	5.00	2.00	14.00	1.00	15.00	0.0	0.0	1.00	0.0	0.0	1.00
81 - 90	5.00	5.00	4.00	1.00	5.00	0.0	0.0	1.00	0.0	0.0	0.0
91 -100	1.00	5.00	3.00	0.0	6.00	0.0	0.0	1.00	1.00	0.0	0.0
>100	258.00	142.00	130.00	32.00	63.00	0.0	4.00	36.00	11.00	1.00	3.00

CUMULATIVE DISTRIBUTION OF POWER PLANTS BY MEGAWATT CAPACITY
CCUNTRY 1974

MW	FOSSIL			NUCLEAR	COMBUSTION TURBINE	DIESEL	COMBINED CYCLE	HYDRO	HYDRO PUMP-STR	GEOTHERM	OTHER
	COAL	OIL	GAS								
1 - 10	9.00	3.00	6.00	0.0	11.00	169.00	0.0	2.00	0.0	0.0	2.00
11 - 20	17.00	10.00	29.00	0.0	58.00	186.00	1.00	3.00	0.0	0.0	3.00
21 - 30	29.00	18.00	46.00	0.0	100.00	193.00	1.00	4.00	1.00	0.0	5.00
31 - 40	39.00	23.00	54.00	0.0	116.00	195.00	1.00	4.00	1.00	0.0	7.00
41 - 50	44.00	28.00	70.00	0.0	131.00	195.00	2.00	4.00	2.00	0.0	7.00
51 - 60	47.00	30.00	79.00	0.0	144.00	195.00	2.00	4.00	2.00	0.0	8.00
61 - 70	55.00	38.00	83.00	0.0	154.00	195.00	2.00	5.00	2.00	0.0	8.00
71 - 80	60.00	40.00	97.00	1.00	169.00	195.00	2.00	6.00	2.00	0.0	9.00
81 - 90	65.00	45.00	101.00	2.00	174.00	195.00	2.00	7.00	2.00	0.0	9.00
91 -100	66.00	50.00	104.00	2.00	180.00	195.00	2.00	8.00	3.00	0.0	9.00
>100	324.00	192.00	234.00	34.00	243.00	195.00	6.00	44.00	14.00	1.00	12.00

CUMULATIVE FREQUENCY DISTRIBUTION OF POWER PLANTS BY MEGAWATT CAPACITY
CCUNTRY 1974

MW	FOSSIL			NUCLEAR	COMBUSTION TURBINE	DIESEL	COMBINED CYCLE	HYDRO	HYDRO PUMP-STR	GEOTHERM	OTHER
	COAL	OIL	GAS								
1 - 10	0.03	0.02	0.03	0.0	0.05	0.87	0.0	0.05	0.0	0.0	0.17
11 - 20	0.05	0.05	0.12	0.0	0.24	0.95	0.17	0.07	0.0	0.0	0.25
21 - 30	0.09	0.09	0.20	0.0	0.41	0.99	0.17	0.09	0.07	0.0	0.42
31 - 40	0.12	0.12	0.23	0.0	0.48	1.00	0.17	0.09	0.07	0.0	0.58
41 - 50	0.14	0.15	0.30	0.0	0.54	1.00	0.33	0.09	0.14	0.0	0.58
51 - 60	0.15	0.16	0.34	0.0	0.59	1.00	0.33	0.09	0.14	0.0	0.67
61 - 70	0.17	0.20	0.35	0.0	0.63	1.00	0.33	0.11	0.14	0.0	0.67
71 - 80	0.19	0.21	0.41	0.03	0.70	1.00	0.33	0.14	0.14	0.0	0.75
81 - 90	0.20	0.23	0.43	0.06	0.72	1.00	0.33	0.16	0.14	0.0	0.75
91 -100	0.20	0.26	0.44	0.06	0.74	1.00	0.33	0.18	0.21	0.0	0.75
>100	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

DISTRIBUTION OF POWER PLANTS BY MEGAWATT CAPACITY
COUNTRY 1984

MW	FOSSIL			NUCLEAR	COMBUSTION TURBINE	DIESEL	COMBINED CYCLE	HYDRO		GEOTHERM	OTHER
	COAL	OIL	GAS					HYDRO	PUMP-STR		
1 - 10	6.00	2.00	5.00	0.0	10.00	159.00	0.0	3.00	0.0	0.0	16.00
11 - 20	4.00	6.00	14.00	0.0	45.00	21.00	1.00	0.0	0.0	0.0	6.00
21 - 30	10.00	6.00	12.00	0.0	43.00	7.00	0.0	2.00	1.00	0.0	3.00
31 - 40	7.00	3.00	9.00	0.0	23.00	1.00	1.00	3.00	0.0	0.0	2.00
41 - 50	7.00	4.00	12.00	0.0	17.00	1.00	0.0	0.0	1.00	0.0	0.0
51 - 60	3.00	0.0	9.00	1.00	17.00	0.0	0.0	1.00	0.0	0.0	1.00
61 - 70	5.00	7.00	5.00	0.0	12.00	0.0	0.0	1.00	0.0	0.0	0.0
71 - 80	4.00	0.0	9.00	1.00	17.00	0.0	0.0	1.00	0.0	0.0	1.00
81 - 90	6.00	2.00	5.00	0.0	5.00	0.0	0.0	1.00	0.0	0.0	0.0
91 - 100	1.00	2.00	5.00	0.0	10.00	0.0	0.0	2.00	1.00	0.0	-1.00
>100	341.00	149.00	124.00	106.00	87.00	0.0	20.00	43.00	23.00	1.00	22.00

CUMULATIVE DISTRIBUTION OF POWER PLANTS BY MEGAWATT CAPACITY
COUNTRY 1984

MW	FOSSIL			NUCLEAR	COMBUSTION TURBINE	DIESEL	COMBINED CYCLE	HYDRO		GEOTHERM	OTHER
	COAL	OIL	GAS					HYDRO	PUMP-STR		
1 - 10	6.00	2.00	5.00	0.0	10.00	159.00	0.0	3.00	0.0	0.0	16.00
11 - 20	10.00	8.00	19.00	0.0	55.00	180.00	1.00	3.00	0.0	0.0	22.00
21 - 30	20.00	14.00	31.00	0.0	98.00	187.00	1.00	5.00	1.00	0.0	25.00
31 - 40	27.00	17.00	40.00	0.0	121.00	188.00	2.00	8.00	1.00	0.0	27.00
41 - 50	34.00	21.00	52.00	0.0	138.00	189.00	2.00	8.00	2.00	0.0	27.00
51 - 60	37.00	21.00	61.00	1.00	155.00	189.00	2.00	9.00	2.00	0.0	28.00
61 - 70	42.00	28.00	66.00	1.00	167.00	189.00	2.00	10.00	2.00	0.0	28.00
71 - 80	46.00	28.00	75.00	2.00	184.00	189.00	2.00	11.00	2.00	0.0	29.00
81 - 90	52.00	30.00	80.00	2.00	189.00	189.00	2.00	12.00	2.00	0.0	29.00
91 - 100	53.00	32.00	85.00	2.00	199.00	189.00	2.00	14.00	3.00	0.0	28.00
>100	394.00	181.00	209.00	108.00	286.00	189.00	22.00	57.00	26.00	1.00	50.00

CUMULATIVE FREQUENCY DISTRIBUTION OF POWER PLANTS BY MEGAWATT CAPACITY
COUNTRY 1984

MW	FOSSIL			NUCLEAR	COMBUSTION TURBINE	DIESEL	COMBINED CYCLE	HYDRO		GEOTHERM	OTHER
	COAL	OIL	GAS					HYDRO	PUMP-STR		
1 - 10	0.02	0.01	0.02	0.0	0.03	0.84	0.0	0.05	0.0	0.0	0.32
11 - 20	0.03	0.04	0.09	0.0	0.19	0.95	0.05	0.05	0.0	0.0	0.44
21 - 30	0.05	0.08	0.15	0.0	0.34	0.99	0.05	0.09	0.04	0.0	0.50
31 - 40	0.07	0.09	0.19	0.0	0.42	0.99	0.09	0.14	0.04	0.0	0.54
41 - 50	0.09	0.12	0.25	0.0	0.48	1.00	0.09	0.14	0.08	0.0	0.54
51 - 60	0.09	0.12	0.29	0.01	0.54	1.00	0.09	0.16	0.08	0.0	0.56
61 - 70	0.11	0.15	0.32	0.01	0.58	1.00	0.09	0.18	0.08	0.0	0.56
71 - 80	0.12	0.15	0.36	0.02	0.64	1.00	0.09	0.19	0.08	0.0	0.58
81 - 90	0.13	0.17	0.38	0.02	0.66	1.00	0.09	0.21	0.08	0.0	0.58
91 - 100	0.13	0.18	0.41	0.02	0.70	1.00	0.09	0.25	0.12	0.0	0.56
>100	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

APPENDIX E

Summary of Typical Zoning Ordinance
Provisions

APPENDIX E: Summary of Typical Zoning Ordinance Provisions

The following tables display for each ordinance:

- (i) the types of land uses allowed in each zoning district,
- (ii) the presence of provisions designed to facilitate common-site, multibuilding development,
- (iii) The types of ICES components permitted in each zoning district, and
- (iv) the presence of district-specific performance standards.

The "Permitted Uses" are the land use types with which developers can design communities within the use list constraint of each zone. The "Complexes" portion of the table indicates whether explicit provisions were included to aid developers of multibuilding projects, and the districts where Planned Unit Developments were permitted either by right or as a "Special Use." The district use lists were also examined to see the specific types of ICES components allowed within each district. With the exception of "Prime Movers," the ICES components listed in the tables were those most frequently mentioned in the reviewed zoning ordinances. "Prime Movers" denotes any type of power and steam production plant whether large or small, since no size or type distinction was encountered in any ordinance. The presence of district performance standards is also indicated for the more commonly considered and explicitly regulated nuisances or safety hazards -- air and noise emissions, and fuel storage. Water quality standards (including thermal emission regulations) are notable only because of their absence in all of the ordinances examined.

TABLE A.1. Luzerne County, Pennsylvania (1970)

ZONES	C1	A1	S1	R1-2	R-3	B-1,2, D	B3	B4	M1	M2	M3					
PERMITTED USES	RESIDENTIAL					COMMERCIAL			INDUSTRIAL							
SINGLE FAMILY	X	X	X	X	X											
TWO FAMILY		X		X	X											
APARTMENTS					X											
COMMERCIAL					X	X	X	X								
INDUSTRIAL									X	X	X					
COMPLEXES																
RESIDENTIAL	X	X	X	X	X											
COMMERCIAL	X	X	X	X	X											
INDUSTRIAL																
MIXED	X	X	X	X	X											
SPECIAL PURPOSE		X ^a	X ^b	X ^b		X ^c										
ALLOWS PUD?	X	X	X	X	X											
ICES COMPONENTS																
PRIME MOVERS										X	X					
GAS/LIQUID FUEL PROD'N										X	X					
WATER TREATMENT									X	X	X					
RESERVOIRS																
WASTE TREATMENT	X								X	X	X					
INCINERATORS										X	X					
LANDFILLS									X	X	X					
PERFORMANCE STANDARDS																
AIR										X	X					
WATER																
NOISE										X	X					
FUEL STORAGE																

^a Airport^c Shopping Center^b Hospital

TABLE A.2. Will County, Illinois (1969)

ZONES	R-1,2	R-3,4	A-1,2	C1-C8	C9 ^b	I1	I2	I3								
PERMITTED USES	RESIDENTIAL			COMMERCIAL		INDUSTRIAL										
SINGLE FAMILY	X	X	X													
TWO FAMILY		X														
APARTMENTS		X														
COMMERCIAL				X	X	X	X	X								
INDUSTRIAL						X	X	X								
COMPLEXES																
RESIDENTIAL	X	X	X													
COMMERCIAL				X	X	X	X	X								
INDUSTRIAL					X ^c	X	X	X								
MIXED					X	X	X	X								
SPECIAL PURPOSE			X ^a		X ^a											
ALLOWS PUD?	X	X	X	X	X	X	X	X								
ICES COMPONENTS																
PRIME MOVERS								X								
GAS/LIQUID FUEL PROD'N						X	X	X								
WATER TREATMENT						X	X	X								
RESERVOIRS						X	X	X								
WASTE TREATMENT			X	X	X	X	X	X								
INCINERATORS							X	X								
LANDFILLS			X				X	X								
PERFORMANCE STANDARDS																
AIR						X	X	X								
WATER																
NOISE						X	X	X								
FUEL STORAGE						X	X	X								

^aHospital

^cResearch and Light Industrial Park District

^bOffice and Research Park District

TABLE A.3. Columbia County, Pennsylvania (1966)

ZONES	A, R/E	R/S	C/N	C/TS	C/G	IND											
PERMITTED USES	RESIDENTIAL		COMMERCIAL			INDUSTRIAL											
SINGLE FAMILY	X	X															
TWO FAMILY		X															
APARTMENTS		X															
COMMERCIAL			X	X	X	X											
INDUSTRIAL						X											
COMPLEXES																	
RESIDENTIAL	X	X															
COMMERCIAL	X		X	X	X	X											
INDUSTRIAL	X					X											
MIXED						X											
SPECIAL PURPOSE																	
ALLOWS PUD?	X	X	X	X	X	X											
ICES COMPONENTS																	
PRIME MOVERS						X											
GAS/LIQUID FUEL PROD'N						X											
WATER TREATMENT						X											
RESERVOIRS						X											
WASTE TREATMENT						X											
INCINERATORS						X											
LANDFILLS	X	X	X		X	X											
PERFORMANCE STANDARDS																	
AIR																	
WATER																	
NOISE																	
FUEL STORAGE																	

TABLE A.4. Chicago, Illinois (1968)

ZONES	R-1,2	R3- R8	B1	B-2,3 6,7	B-4,5	C-1,2	C-3,4	M1	M-2,3							
PERMITTED USES	RESIDENTIAL			COMMERCIAL				INDUSTRIAL								
SINGLE FAMILY	X	X														
TWO FAMILY		X														
APARTMENTS		X	X													
COMMERCIAL			X	X	X	X	X	X	X							
INDUSTRIAL								X	X							
COMPLEXES																
RESIDENTIAL	X	X														
COMMERCIAL			X	X	X	X	X	X	X							
INDUSTRIAL								X	X							
MIXED								X	X							
SPECIAL PURPOSE		X ^{a, b}	X ^{a, b}													
ALLOWS PUD?	X	X	X	X	X	X	X	X	X							
ICES COMPONENTS																
PRIME MOVERS								X	X							
GAS/LIQUID FUEL PROD'N									X							
WATER TREATMENT	X	X	X	X	X	X	X	X	X							
RESERVOIRS	X	X	X	X	X	X	X	X	X							
WASTE TREATMENT																
INCINERATORS								X	X							
LANDFILLS								X	X							
PERFORMANCE STANDARDS																
AIR ^c																
WATER																
NOISE				X	X	X	X	X	X							
FUEL STORAGE						X	X	X	X							

^aHospital^cMunicipal Air Pollution Regulations^bUniversity

TABLE A.5. Bethlehem, Pennsylvania (1973)

ZONES	RR	R-S,G T,M	CB	CG	CL	CS ^a	CM ^b	I ^d	PI ^c	LI	HI						
PERMITTED USES	RESIDENTIAL		COMMERCIAL						INDUSTRIAL								
SINGLE FAMILY	X	X															
TWO FAMILY		X															
APARTMENTS		X	X	X													
COMMERCIAL			X	X	X	X	X		X	X	X						
INDUSTRIAL									X	X	X						
COMPLEXES																	
RESIDENTIAL			X			X											
COMMERCIAL						X	X										
INDUSTRIAL									X								
MIXED						X											
SPECIAL PURPOSE		X ^e						X ^{e,f}									
ALLOWS PUD?		X					X ^g		X								
ICES COMPONENTS																	
PRIME MOVERS									X	X	X						
GAS/LIQUID FUEL PROD'N											X						
WATER TREATMENT																	
RESERVOIRS									X	X	X						
WASTE TREATMENT									X	X	X						
INCINERATORS											X						
LANDFILLS									X	X	X						
PERFORMANCE STANDARDS																	
AIR																	
WATER																	
NOISE									X	X	X						
FUEL STORAGE																	

^a Shopping Center District^b Office/Research Center District^c Planned Industrial District^d Institutional District^e Hospital^f University^g Special Use

TABLE A.6. Danville, Illinois (1970)

ZONES	R-1,2	R3	R4	P1	B-1,2	B3	B-4,5 6	I1	I2							
PERMITTED USES	RESIDENTIAL			COMMERCIAL				INDUSTRIAL								
SINGLE FAMILY	X	X	X													
TWO FAMILY		X	X													
APARTMENTS			X	X												
COMMERCIAL				X	X	X	X									
INDUSTRIAL								X	X							
COMPLEXES																
RESIDENTIAL	X	X	X													
COMMERCIAL							X ^b									
INDUSTRIAL																
MIXED																
SPECIAL PURPOSE			X ^a	X ^a	X ^a	X ^a										
ALLOWS PUD?	X	X	X													
ICES COMPONENTS																
PRIME MOVERS									X							
GAS/LIQUID FUEL PROD'N									X							
WATER TREATMENT								X	X							
RESERVOIRS																
WASTE TREATMENT								X	X							
INCINERATORS									X							
LANDFILLS									X							
PERFORMANCE STANDARDS																
AIR																
WATER																
NOISE																
FUEL STORAGE																

^aHospitals

^bPlanned Shopping Center

TABLE A.7. Bloomington, Illinois (1968)

ZONES	R1-A, B	R2	R3A	R3B	RU-1, 2	C-1, 2	C3, M1, 1A	M2									
PERMITTED USES	RESIDENTIAL					COMM	INDUSTRIAL										
SINGLE FAMILY	X	X	X	X	X												
TWO FAMILY		X	X	X													
APARTMENTS			X	X													
COMMERCIAL						X	X										
INDUSTRIAL							X	X									
COMPLEXES																	
RESIDENTIAL	X	X	X	X	X												
COMMERCIAL																	
INDUSTRIAL																	
MIXED																	
SPECIAL PURPOSE		X ^{a, b}		X ^a	X ^{a, b, c}												
ALLOWS PUD?	X	X	X ^d	X ^d	X												
ICES COMPONENTS																	
PRIME MOVERS								X									
GAS/LIQUID FUEL PROD'N								X ^d									
WATER TREATMENT								X									
RESERVOIRS								X									
WASTE TREATMENT								X									
INCINERATORS								X									
LANDFILLS								X ^d									
PERFORMANCE STANDARDS																	
AIR																	
WATER																	
NOISE		NO MENTION															
FUEL STORAGE																	

^aHospital^bUniversity^cAirport^dSpecial Use

TABLE A.8. Lebanon, Pennsylvania (1971)

ZONES	RLD	RHD	CBD	CN	C-A	O-I ^a	M										
PERMITTED USES	RESIDENTIAL		COMMERCIAL				INDUSTRIAL										
SINGLE FAMILY	X	X															
TWO FAMILY		X															
APARTMENTS		X	X		X	X											
COMMERCIAL			X	X	X	X	X										
INDUSTRIAL							X										
COMPLEXES																	
RESIDENTIAL																	
COMMERCIAL																	
INDUSTRIAL																	
MIXED																	
SPECIAL PURPOSE	X ^{b, e}	X ^{b, d}				X ^{b, c, d}											
ALLOWS PUD?		NO MENTION															
ICES COMPONENTS																	
PRIME MOVERS																	
GAS/LIQUID FUEL PROD'N																	
WATER TREATMENT																	
RESERVOIRS																	
WASTE TREATMENT																	
INCINERATORS																	
LANDFILLS																	
PERFORMANCE STANDARDS																	
AIR																	
WATER																	
NOISE		NO MENTION															
FUEL STORAGE																	

^aOffice-Institutional District

^bHospital

^cUniversity

^dSpecial Use

TABLE A.9. Fairfax, Virginia

ZONES	R-1,2	R3	RT	M1	PD ^a	CPD ^b	CIL	C-1,2 3	I1	I2						
PERMITTED USES	RESIDENTIAL					COMMERCIAL			INDUSTRIAL							
SINGLE FAMILY	X	X			X	X										
TWO FAMILY		X	X		X	X										
APARTMENTS			X	X	X	X										
COMMERCIAL					X	X	X	X								
INDUSTRIAL									X	X						
COMPLEXES																
RESIDENTIAL					X	X										
COMMERCIAL						X										
INDUSTRIAL																
MIXED					X ^d	X										
SPECIAL PURPOSE	X ^c	X ^c				X ^c										
ALLOWS PUD?					X	X										
ICES COMPONENTS																
PRIME MOVERS										X						
GAS/LIQUID FUEL PROD'N										X						
WATER TREATMENT										X						
RESERVOIRS										X						
WASTE TREATMENT										X						
INCINERATORS										X						
LANDFILLS										X						
PERFORMANCE STANDARDS																
AIR							X	X	X	X						
WATER																
NOISE							X	X	X	X						
FUEL STORAGE																

^aPlanned Development District^bCommercial Planned Development District^cHospital^dLocal Shopping Only

TABLE A.10. Effingham, Illinois (1974)

ZONES	NU	R1	R2	R3	PRD ^b	B1	B2	B3	B4 ^c	B5	POM ^d	M1	M2			
PERMITTED USES	Residential					Commercial						Industrial				
SINGLE FAMILY	X	X	X	X	X	X	X	X				X				
TWO FAMILY				X	X	X	X	X				X				
APARTMENTS				X	X	X	X	X				X				
COMMERCIAL						X	X	X	X	X	X	X	X			
INDUSTRIAL											X ^e	X ^e	X			
COMPLEXES																
RESIDENTIAL																
COMMERCIAL																
INDUSTRIAL									X		X					
MIXED											X ^e					
SPECIAL PURPOSE				X ^a	X ^a						X					
ALLOWS PUD?					X						X					
ICES COMPONENTS																
PRIME MOVERS													X			
GAS/LIQUID FUEL PROD'N													X ^f			
WATER TREATMENT													X			
RESERVOIRS													X			
WASTE TREATMENT													X ^f			
INCINERATORS													X			
LANDFILLS													X ^f			
PERFORMANCE STANDARDS																
AIR																
WATER		No Mention														
NOISE																
FUEL STORAGE																

^aHospital^bFloating PUD Zone
Districts^cPlanned Shopping Center District
Applicable to other residential^dPlanned Office and Limited District
Industrial^eLight Manufacturing^fSpecial Use

TABLE A.11. Escambia-Santa Rosa Counties, Florida (Model Ordinance)

ZONES	R1, R2	R3	R4	C-1, 2	C3	I1	I2										
PERMITTED USES	RESIDENTIAL			COMMERCIAL		INDUSTRIAL											
SINGLE FAMILY	X	X	X														
TWO FAMILY		X	X														
APARTMENTS			X														
COMMERCIAL				X	X												
INDUSTRIAL						X	X										
COMPLEXES																	
RESIDENTIAL	X	X	X														
COMMERCIAL																	
INDUSTRIAL																	
MIXED																	
SPECIAL PURPOSE			X ^{a, b}														
ALLOWS PUD?	X	X	X														
ICES COMPONENTS																	
PRIME MOVERS							X										
GAS/LIQUID FUEL PROD'N							X										
WATER TREATMENT	X	X	X	X	X	X	X										
RESERVOIRS																	
WASTE TREATMENT	X	X	X	X	X	X	X										
INCINERATORS							X										
LANDFILLS																	
PERFORMANCE STANDARDS																	
AIR					X	X	X										
WATER																	
NOISE					X	X	X										
FUEL STORAGE																	

^aSports Complex

^bAirport

TABLE A.12. Genessee County, Michigan (Model Ordinance)

ZONES	RA	A1	A-2.3	C ^b	A	B	I										
PERMITTED USES	RESIDENTIAL				COMMERCIAL		INDUSTRIAL										
SINGLE FAMILY	X	X	X	X													
TWO FAMILY	X		X														
APARTMENTS	X																
COMMERCIAL					X	X											
INDUSTRIAL							X										
COMPLEXES																	
RESIDENTIAL	X ^a	X ^a	X ^a														
COMMERCIAL						X ^f											
INDUSTRIAL							X ^g										
MIXED																	
SPECIAL PURPOSE	X ^{c,d}	X ^d	X ^d														
ALLOWS PUD?	X ^e	X ^e	X ^e														
ICES COMPONENTS																	
PRIME MOVERS							X										
GAS/LIQUID FUEL PROD'N							X										
WATER TREATMENT	X	X					X										
RESERVOIRS							X										
WASTE TREATMENT							X										
INCINERATORS							X										
LANDFILLS							X										
PERFORMANCE STANDARDS																	
AIR							X										
WATER																	
NOISE							X										
FUEL STORAGE																	

^aCluster Provision

^bMobile Home District

^cAirport

^dHospital

^eSpecial Use

^fShopping Center Provision

^gIndustrial Park Provision

TABLE A.13. Marion County, Indiana (Model Ordinance)

ZONES	D1-D5	D6	D7-D10	DP ^a	CBD-1,2	CBD3	CBDS	C1	C2	C4	C-3, 5,6	C7	CS	I-1,2	I-3,4	I5
PERMITTED USES	RESIDENTIAL				COMMERCIAL									INDUSTRIAL		
SINGLE FAMILY	X	X	X	X												
TWO FAMILY		X	X	X												
APARTMENTS			X	X		X	X		X	X			X			
COMMERCIAL					X	X	X	X	X	X	X	X	X			
INDUSTRIAL												X		X	X	X
COMPLEXES																
RESIDENTIAL		X ^b		X			X						X			
COMMERCIAL							X			X ^d			X			
INDUSTRIAL							X ^c						X	X ^e	X ^e	X ^e
MIXED							X					X	X			
SPECIAL PURPOSE																
ALLOWS PUD?				X			X						X			
ICES COMPONENTS																
PRIME MOVERS														X	X	X
GAS/LIQUID FUEL PROD'N															X	X
WATER TREATMENT							X						X			X
RESERVOIRS							X						X			X
WASTE TREATMENT							X						X			X
INCINERATORS																X
LANDFILLS																
PERFORMANCE STANDARDS																
AIR																
WATER																
NOISE																
FUEL STORAGE																

^aPUD District^cR&D Park Provision^eIndustrial Park (Special Use).^bCluster Provision^dRegional Shopping Center

APPENDIX F

Summary of State Level Utility Facility
Siting Law

Appendix F. Summary of State Level Utility
Facility Siting Regulation

State	Minimum Capacity ¹ MWe	Minimum Transmission ² Voltage, Length kV x (miles)	Applicable Statute	Primary Regulatory Body	Requirements			
					Public Hearing	Permit	EIS ³	"One Stop" ⁴
Arizona	100	115	S.L. 40-360: Power Line & PP Siting(1971)	PP Siting Committee		X		X
Arkansas	50	100 x (10), 170 x (1)	1973 Utility Fac. Env. Protection Act	Public Service Commission	X	X	X	
California	50	69	1974 Comprehensive Energy Act	Engy. Res. Cons. & Dev. Comm.	X	X	X	X
Connecticut	Any	69	N/A	Power Fac. Evaluation Council		X		
Delaware	Any ⁵	Any ⁵	Coastal Zone Act of 1971	State Planning Office		X	X	
Florida	Any	"Associated Line"	Power Plant Siting Act of 1973	Division of State Planning		X		X
Kentucky	Any	400	1974 Power Plant Siting Law	Public Service Commission	X	X		
Maine	1	125	Site Selection Act	Land Use Regulatory Comm'n.		X		
Maryland	Any	69	Power Plant Siting Act	Dept. of Natural Resources			X	
Massachusetts	100	69 x (1)	1974 Power Plant Siting Law	Elec. Power Facil. Siting Coun.		X		X
Minnesota	50	200 x (1)	Power Plant Siting Act of 1971	Environmental Quality Comm'n.				
Montana	50	34.5	Utility Siting Act of 1973	Dept. of Natural Resources		X		
Nebraska	N/A	N/A	N/A	Power Review Board	X	X		
Nevada	Any	60	1971 Utility Environmental Prot. Act	Public Service Commission		X	X	
New Hampshire	50	100 x (10)	N/A	Bulk Power Site Eval. Comm'n.	X	X	X	
New Jersey	Any ⁵	Any ⁵	Coastal Area Fac. Review Act of 1973	Dept. of Environmental Prot.		X		
New Mexico	300	230	N/A	Energy Resources Board		X		
New York	50	100 x (10), 125 x (1)	1970 Public Services Law	State Power Siting Board		X		X
North Dakota	50	200	1973 Energy Facility Siting Act	Public Service Commission		X		
Ohio	50	125	N/A	Power Siting Commission		X		X
Oregon	200	200	1971 PP Siting and Env. Prot. Act	Nuclear & Thermal Energy Council		X		
Pennsylvania	N/A	N/A	N/A	Public Utility Commission	X	X		
South Carolina	75	125	U	U	U	U	U	U
Vermont	"Major"	"Major"	N/A	Environmental Review Board		X	X	
Washington	250	200	1970 Thermal Power Plant Siting Act	Thermal PP Site Eval. Council	X	X	X	
Wisconsin	300	100	Power Plant Siting Act of 1975	Public Service Commission		X		
Wyoming	100	"Associated Line"	1975 Industrial Plant Siting Act	Industrial Siting Council		X		

¹ Minimum Plant Size Required

N/A = Not Applicable

² Minimum Transmission Line Voltage and Length Regulated

U = Unavailable

³ Environmental Impact Statement Required

⁴ One-Stop Permit Procedure Used

⁵ Coastal Zone Facilities Only

State Level Utility Facility Siting Regulations

ARIZONA:

Power plant siting in
Arizona is controlled

by the Power Plant Siting Committee created in 1971. The committee is composed of representatives from several state agencies and other public representatives and has broad oversight authority over power plant sites and the installation of transmission lines. The primary criteria for site selection is based upon the protection of the environment and population groups and communities adjoining proposed sites. Power companies must file a 10-year forecast with the committee which provides a one-stop certification process.

ARKANSAS:

The siting of large
electrical power

plants is a major land use problem for Arkansas. The 1973 Utility Facility Environmental Protection Act provides that a company building a power plant or transmission lines must obtain a certificate of environmental compatibility from the Arkansas Public Service Commission (PSC). The applicant must describe the facility, its need, cost, alternative locations, and environmental impact. State agencies, localities, and citizens are given time for statements and public hearings. The commission then makes its decision based on the need for the facility; whether the facility is in the public interest; the environmental impact; and conformity to local, state, and regional laws. The act also requires each public utility to furnish a report annually to the Public Service Commission describing the major utility facilities which will be required to supply system demands during the two-year forecast period.

CALIFORNIA:

The regulation of
power plant siting

in California was included in a 1974 comprehensive energy bill that gives the state the power to enforce local rules and regulations and allows the state to overrule local decisions. Applicants for a power plant have to propose three alternative sites. After an extensive environmental impact statement is filed, a permit can be obtained in a one-step procedure from the new Energy Resource Conservation and Development Commission. The five-member commission is involved in forecasting and planning, certification of facility sites, research and development, and contingency planning for periods of energy shortage.

CONNECTICUT:

The principal responsibility for power plant siting rests with the Connecticut Power Facility Evaluation Council (PFEC). This body has sole jurisdiction over the location of transmission facilities and is required to evaluate the need and environmental impact of both transmission and generating facilities. Municipal governments may regulate, under the Inland Wetlands Act or other regulatory authority, the location of distribution lines, substations, and generating plants. Such regulation is subject to appeal to the PFEC. The Public Utilities Control Authority (PUCA) has jurisdiction over the manner and methods of construction for transmission facilities. There are also roles for the Federal Power Commission and the Nuclear Regulatory Commission in the siting and construction of certain generating facilities.

DELAWARE:

The Coastal Zone Act of 1971 bans all heavy industry and port or dock facilities within two miles of the shoreline. It requires a permit from the State Planning Office for all other manufacturing uses or expansion. In reviewing permit applications, environmental and economic impacts, effects on neighboring land uses, and effects on county and city comprehensive plans are considered.

FLORIDA:

Under the Electrical Power Plant Siting Act of 1973, the Division of State Planning is responsible for annual evaluation of the suitability of the ten-year site plans of the electrical utilities in the state. Power plants and related facilities are subject to a one-step certification. The Bureau of Comprehensive Planning has been delegated the Division's responsibilities for power plant siting. There are 55 electric utilities required to submit 10-year plans for review.

KENTUCKY:

The 1974 Power Plant Siting Law requires an application for certification of environmental compatibility. Based on the application, the state rules on compatibility with air and water pollution standards. A report is then submitted to the Public Service Commission which holds hearings and rules on the issuance of the permit.

MAINE:

Although Maine does not have a comprehensive power plant siting law, power plant and transmission line corridor siting are subject to the approval of the Land Use Regulation Commission in unorganized areas of the state. Power plant siting must comply with the provisions of the state's Site Selection Act in all other areas of the state.

MARYLAND:

The secretary of the DNR is empowered to select and acquire between four and eight power plant sites for future power generating facilities. The need for sites is to be determined by the State Planning Department. Selection is based upon a study of the desirability of each site. Decisions to purchase must be made within two years from the date a site is considered or it must be released. Acquisition may be by contract or condemnation. Sites so purchased are exempt from local zoning. Thereafter, an electric company may purchase or lease (for a 99 year term) a site held by the state at its appraised value. Appraisals are performed by specially constituted groups of three appraisers.

Major decisions are made by the secretary of natural resources with the advice of an advisory committee, other department heads and representatives of several disciplines from state academic institutions.

MASSACHUSETTS:

The 1974 Massachusetts Power Plant Siting

Law established the Electric Power Facilities Siting Council composed of nine gubernatorial appointees who administer a one-stop permit process for site approval.

MINNESOTA:

The 1973 Minnesota Legislature passed

the Power Plant Siting Act authorizing the Environmental Quality Council (EQC) to determine the location of large electric power generating plants and transmission lines. The State Planning Agency, as staff to EQC, is preparing criteria to inventory and rank potential sites and corridors.

MONTANA:

The Montana legislature expanded coverage of the state Utility Siting Act to include any plant that converts to electricity at least 500,000 tons of coal per year. (Approximately 125 MWe at 100% capacity factor.) The Utility Siting Act of 1973 required utilities to obtain a permit from the Department of Natural Resources prior to development of a project. The large application fee is used to plan for and meet the impact of new utility construction. The department has the authority to reject projects not in the public interest.

NEBRASKA:

Nebraska is the only state where power is controlled and supplied by the state. The Power Review Board of the Water Resources Department approves all power plant siting proposals submitted by the public power districts. Power plant siting plans are preceded by public hearings which guarantee public involvement in power siting discussions. Under Nebraska statutes, the state is divided into public power districts with directors of the districts elected by the public.

NEVADA:

The 1971 Utility Environmental Protection Act authorizes the Public Service Commission to review the environmental impact of proposed fossil fuel or nuclear power plants and transmission lines prior to issuing siting and operating permits. The governor's interagency Environmental Council reviews environmental statements and submits its findings to the Public Service Commission.

NEW HAMPSHIRE:

Approval for new power generation facilities and transmission lines must be given by the state Bulk Power Site Evaluation Committee created by the 1971 legislature. The committee regulates the planning, siting, and construction of bulk power supply facilities (defined as generating facilities of over 50 megawatts and transmission lines of more than 100 kilovolts) in cooperation with the Public Utilities Commission. The committee is composed of 13 designated state officials from the major resource agencies. In 1974, the Site Evaluation Committee also was designated by statute to review and approve the planning, siting, construction, and operation of energy facilities (defined to include oil refineries, liquified natural gas and coal conversion processing plants, and ancillary terminal pipeline and storage facilities). Planning activities to date include review and comment on the utility companies' ten-year construction plans, identification of possible sites, and environmental impact analyses of tentative sites for all construction within five years. Regulatory activities have been limited to review and hearing procedures and issuance of permits for energy facilities.

NEW JERSEY:

Under the Coastal area Facility Review Act of 1973, the state Department of Environmental Protection regulates land use in the coastal zone through development permit requirements. Energy facility siting is viewed as one of the major pressures facing New Jersey coastal areas, though regulations are primarily focused on anticipated Outer Continental Shelf drilling activities, floating off-shore nuclear systems, and deepwater ports.

NEW MEXICO:

The Energy Resources

board is formulating new power plant siting recommendations to give the state more influence in the siting procedure. The state now provides advice and technical assistance. The construction of power plants must comply with the state water laws requiring utilities to obtain a permit from the state engineer to ensure that water use does not injure other area water users.

NEW YORK:

Article VII of the
Public Services Law

enacted in 1970 requires utilities to obtain a certificate of environmental compatibility and need prior to site preparation for electric power transmission lines and fuel gas transmission facilities. Article VIII of the law enacted in 1972 established a state board on electric generating siting and environment. The article also required a certificate of environmental compatibility and need for the siting of major steam generating facilities.

The State Power Siting Board consists of five individuals appointed by the governor to provide one-stop certification of energy facilities and to develop a ten-year plan for the state's energy needs.

NORTH DAKOTA:

In 1973, the Legislature passed a bill requiring proposals for new energy facilities to be examined and approved by the state Public Services Commission. "Energy facilities" include anticipated coal gasification plants as well as electric generating stations and transmission lines.

OHIO:

The Ohio Power Siting Commission issues certificates of Environmental Compatibility and Public Need for electric generating plants, electric transmission lines, and gas transmission lines. Major utilities are required to furnish ten-year forecasts of needs and prospective sites for major facilities. Each year the commission must publish the general locations of proposed power plant sites and transmission lines. The Ohio law has a one-stop application process.

OREGON:

A 1971 legislative power plant siting and environmental protection bill created the Oregon Nuclear and Thermal Energy Council. Prior to passage of the legislation, the Nuclear Development Coordinating Committee and the Nuclear Plant Siting Task Force had been created by executive order. The council is responsible for implementing a state policy to develop energy resources and disposal of resulting waste in a manner consistent with state environmental policies.

Dams and power facilities on the Columbia River form part of a power pool that supplies electricity to the entire Pacific Northwest. Power plant siting permits are required from the Land and Conservation Development Commission.

PENNSYLVANIA:

There is no comprehensive legislation governing site selection procedures for generating plants and transmission lines. The Pennsylvania Public Utilities Commission's rules and regulations provide for plant and transmission line location approval based upon public utility, financial management, feasibility of land acquisition, needs for service in the area, prevention of competitive conditions, and environmental impact. Without the commission's approval, a utility company cannot acquire land using eminent domain or begin construction. An application for either a transmission line or generating facility must include, among other things, the location and identification of historic or scenic sites within specified distances. A copy of the application must be sent to local, county, and regional governmental bodies and planning agencies concerned with natural or historic resources and to the U.S. Department of Interior. The proposed Pennsylvania Power Facilities Planning and Site Approval Act would require the DER to prepare and maintain comprehensive bulk power facilities goals. A board would review and approve the plan. The DER would issue certificates approving construction after a public hearing. In addition, the DER would be empowered to purchase and resell or lease sites for future construction.

VERMONT:

Power plant siting in Vermont is covered in the state's land use law permit system, and is subject to review by the State Environmental Review Board. A 1969 law requires state approval environmental impact statements for major power lines and electrical substation facilities.

The state's review standards include protection from undue water and air pollution, relation to flood plains, the nature of soils and subsoils, and solid waste disposal. Other considerations include adequate water supply, drainage, traffic congestion, the burden on municipal services, and adverse effects on natural areas or historic sites.

WASHINGTON:

The 1970 Thermal Power Plant Siting Act

applies to any stationary thermal power plant with a generating capacity of 250,000 kilowatts or more and floating thermal power plants of 50,000 kilowatts or more including associated transmission lines. The purpose of the act is to insure that the location and operation of power plants will produce minimal adverse effects on the environment. The Thermal Power Plant Site Evaluation Council has authority to adopt rules, regulations and policies, to hold hearings, and to receive applications for site location.

After receipt of an application for certification, the Council commissions an independent study to determine environmental consequences of each proposed site application with the cost of the study being paid by the applicant. Public hearings are held within 60 days of receipt of the application after which the council makes a recommendation to the governor. The governor's decision is subject to judicial review. Under the act, the attorney general is mandated to appoint an assistant or special attorney general as counsel for the environment to represent public interest in protecting environmental concerns for the duration of certification proceedings.

WISCONSIN:

The newly-passed Wisconsin power plant

(late 1975) siting legislation requires all electric utilities to submit to the state Public Service Commission a ten-year plan of proposed operations and construction of facilities. The plan must include location of proposed generating facilities and transmission lines, alternative locations, projected power needs and supporting data. The plans of the utilities are circulated to several agencies, including the State Planning Office, for comment. After considering the comments of reviewing agencies, the Public Service Commission may approve the plans or request changes therein. Legislation prohibits any electric utility from acquiring land for any generating facility or high voltage line before obtaining permission from the Public Service Commission.

WYOMING:

In 1975, legislation regulating industrial plant siting, including power plant siting was enacted. The law creates a seven member Industrial Siting Council to review and grant permit applications for construction of plants. The council has the authority to delay construction until neighboring communities are capable of absorbing the influx of workers attracted by major projects.

APPENDIX G

Summary of Utility Commission Authority for
Reviewing Environmental Aspects of
Proposed Sites

APPENDIX G

Certificates, Licenses and Permits

State	The Commission has authority to -						
	Set legal standards or criteria for certification to include --						
	Guidelines or standards for evaluating --					Procedures to assure public participation in the certification proceedings through -	
	The effects of planned rights of way, sites and facilities on environmental values affecting -				Relative environmental impacts of alternative sites		
	Air pollution controls	Water pollution controls	Water rights and usage	Use of land			
FPC FCC	X	X	X	X	X X		X X
Alabama							
Alaska	X	X	X	X	X		X
Arizona							X
Arkansas				X			
California	X	X		X	X		X
Colorado	X	X	X	X	X		X
Connecticut							
Delaware 80/ District of Columbia							
Florida							X
Georgia							
Hawaii							
Idaho				X	X		X
Illinois	X	X	X	X	X		X
Indiana							X
Iowa							X
Kansas							X
Kentucky							X
Louisiana							X
Maine							X
Maryland							X
Massachusetts				X			X
Michigan							X
Minnesota							
Mississippi							X
Missouri							X
Montana 81/ Nebraska							
Nevada	X				X		X
New Hampshire	X	X	X	X	X		X
New Jersey	X	X	X	X	X		X
New Mexico	X	X			X		X
New York							X
North Carolina					X		X
North Dakota							X

APPENDIX C

Certificates, Licenses and Permits (Contd.)

State	The Commission has authority to -						
	Set legal standards or criteria for certification to include -						
	Guidelines or standards for evaluating --						
	The effects of planned rights of way, sites and facilities on environmental values affecting -				Relative environmental impacts of alternative sites		Procedures to assure public participation in the certification proceedings through -
	Air pollution controls	Water pollution controls	Water rights and usage	Use of land			
Ohio							
Oklahoma 80/							
Oregon							X
Pennsylvania					X		
Puerto Rico	X	X	X		X		X
Rhode Island	X	X	X	X			X
South Carolina	X	X	X	X	X		X
South Dakota							X
Tennessee							X
Texas							
Utah							X
Vermont			X		X		X
Virginia			X	X	X		X
Virgin							
Islands 80/							X
Washington							
West Virginia							X
Wisconsin	X	X		X	X		X
Wyoming	X	X		X	X		X
Jamaica							
Totals 83/							
Yes	13	12	10	14	17		40
No	41	42	44	40	37		14

Source: Federal Power Commission

APPENDIX G

Certificates, Licenses and Permits (Contd.)

State	The Commission has authority to require certificates of convenience and necessity for -									
	Initiating service				Constructing major additions -					
					Generating plant			Transmission lines		
	Electric				Electric			Electric		
	Private	Public	Cooperative		Private	Public	Cooperative	Private	Public	Cooperative
FPC FCC										
Alabama	X				X			X		
Alaska	X	X	X							
Arizona	X		X							
Arkansas	X		X		X		X	X		X
California	X		X		X 8/			X 13/	X 13/	X 13/
Colorado 27/	X	X	X		9/	9/	9/	9/	9/	9/
Connecticut 28/										
Delaware 29/	X		X							
District of Columbia										
Florida										
Georgia										
Hawaii										
Idaho	X				10/ X			10/ X		
Illinois					X			X 14/		
Indiana										
Iowa								X	X	X
Kansas	X		X					X	5/	X
Kentucky	X		X		X		X	X		X
Louisiana	X		X		X		X	X		X
Maine	X	X	X		X 1/	X 1/	X 1/	X 1/	X 1/	X 1/
Maryland	X 2/	X	X		X	X	X	X	X	X
Massachusetts								X 15/	X 15/	
Michigan										
Minnesota 30/										
Mississippi	X	X	X		X		X	X		X
Missouri	X									
Montana 31/										
Nebraska										
Nevada	X		X		X		X	X		X
New Hampshire					X			X		
New Jersey 32/										
New Mexico	X		X		X		X	X		X
New York	X				11/ Nuclear	6.11/		X	X	X
North Carolina	X									
North Dakota	X							X		

APPENDIX G

Certificates, Licenses and Permits (Contd.)

State	The Commission has authority to require certificates of convenience and necessity for -									
	Initiating service				Constructing major additions -					
					Generating plant			Transmission lines		
	Electric				Electric			Electric		
	Private	Public	Cooperative		Private	Public	Cooperative	Private	Public	Cooperative
Ohio	X				<u>12/</u>	<u>12/</u>	<u>12/</u>	<u>12/</u>	<u>12/</u>	<u>12/</u>
Oklahoma <u>29/</u>										
Oregon <u>33/</u>	X	X						X <u>16/</u>	X <u>16/</u>	X <u>16/</u>
Pennsylvania										
Puerto Rico										
Rhode Island	X	X	X		X	X	X	X	X	X
South Carolina	X				X			X		
South Dakota										
Tennessee	X									
Texas <u>34/</u>										
Utah	X		X		X		X	X <u>17/</u>		X
Vermont	X	X	X		X	X	X	X	X	X
Virginia	X		X		X		X	X		X
Virgin Islands <u>29/ 35/</u>										
Washington										
West Virginia	X	X	X		X	X	X	X	X	X
Wisconsin	X	X	<u>7/</u>		X	X	<u>7/</u>	X	X	<u>7/</u>
Wyoming	X	X	X		X	X	X	X	X	X
Jamaica <u>36/</u>										
Totals <u>37/</u>										
Yes	31	11	20		21	7	14	27	12	19
No	23	43	34		33	47	40	27	42	35

Source: Federal Power Commission

APPENDIX H

Summary of Best Practicable Control Techniques
Currently Available (BPCTCA) and Best Available
Technology Economically Achievable (BATEA) for Fossil
Power Facilities

APPENDIX H

Best Practicable Control Techniques Currently Available (BPCTCA) and Best Available Technology Economically Achievable (BATEA) for Steam Electric Plant Discharges.

Stream Pollutant	BPCTCA Limit, mg/l		BATEA Limit, mg/l		Limit for New Sources, mg/l	
	Max	Avg	Max	Avg	Max	Avg
All Streams						
pH (except once-through cooling)		6.0-9.0		6.0-9.0		6.0-9.0
PCBs		No discharge		No discharge		No discharge
Low-volume Waste Streams						
TSS	100	30	100	30	100	30
Oil and grease	20	15	20	15	20	15
Bottom-ash Transport Water						
TSS	100	30	100	30	100	30
Oil and grease	20	15	20	15	20	15
Flyash Transport Water						
TSS	100	30	100	30	No discharge	
Oil and grease	20	15	20	15	No discharge	
Metal-Cleaning Wastes						
TSS	100	30	100	30	100	30
Oil and grease	20	15	20	15	20	15
Copper (total)	1	1	1	1	1	1
Iron (total)	1	1	1	1	1	1
Boiler Blowdown						
TSS	100	30	100	30	100	30
Oil and grease	20	15	20	15	20	15
Copper (total)	1	1	1	1	1	1
Iron (total)	1	1	1	1	1	1
Once-through Cooling Water						
Free available chlorine	0.5	0.2	0.5	0.2	0.5	0.2
Cooling Tower Blowdown						
Free available chlorine	0.5	0.2	0.5	0.2	0.5	0.2
Zinc			1	1		
Chromium			0.2	0.2		
Phosphorus			5	5		
Other corrosion inhibitors	Limits determined on a case-by-case basis					
Material-storage Runoff						
TSS	50		50		50	
pH	6.0-9.0		6.0-9.0		6.0-9.0	

Source: Power, (April, 1977)

APPENDIX I

Typical Boiler Wastewater Emissions

APPENDIX I

Typical Coal Pile Runoff Pollutant Concentrations
at Four Selected Sites

Plant	A	B	C	D
Alkalinity	6	0	-	-
Total Solids	1,330	9,999	-	-
TDS	720	7,743	-	28,970
TSS	610	22	-	100
Ammonia	0	1.77	-	-
Nitrate	0.3	1.9	-	-
Phosphorus	-	1.2	-	-
Turbidity	505	-	-	-
Acidity	-	-	-	21,700
Total Hardness	130	1,109	-	-
Sulfate	525	5,231	6,837	19,000
Chloride	3.6	481	-	-
Aluminum	-	-	-	1,200
Chromium	0	0.37	-	15.7
Copper	1.6	-	-	1.8
Iron	0.168	-	0.368	4,700
Magnesium	0	89	-	-
Zinc	1.6	2.43	-	12.5
Sodium	1,260	160	-	-
pH	2.8	3	2.7	2.1

	Flow, gpd/MW	Dissolved solids, mg/l
Boiler cleaning	4	3,000
Fireside cleaning	5	3,000
Air-preheater cleaning	100	8,000
Lab drains	10	200
Boiler blowdown	100	50
Recirc ash-handling	300	3,000
Recirc wet scrubber	20	2,000
Ion-exchange regen	88	6,000
Evaporator	-	-
Miscellaneous	3.22	300
Floor drains (excess of recycle)	30	300
TOTAL (or AVG)	660	(3,668)

APPENDIX I (Contd.)

Characteristics of Once-through Ash Pond Discharges

Parameter	Flyash Pond Ave	Bottom Ash Pond Ave
Flow (gpm)	6,212.5	16,152
Total alkalinity (as CaCO_3)	-	85
Phen. alkalinity (as CaCO_3)	0	0
Conductivity ($\mu\text{mhos/cm}$)	810	322
Total hardness (as CaCO_3)	260.5	141.5
pH	4.4	7.2
Dissolved solids	508	167
Suspended solids	62.5	60
Aluminum	7.19	3.49
Ammonia (as N)	0.43	0.12
Arsenic	0.010	0.006
Barium	0.25	0.15
Beryllium	0.011	<0.01
Cadmium	0.037	0.0011
Calcium	136	40.12
Chloride	7.12	8.38
Chromium	0.067	0.009
Copper	0.31	0.065
Cyanide	<0.01	<0.01
Iron	1.44	5.29
Lead	0.058	0.016
Magnesium	13.99	5.85
Manganese	0.48	0.16
Mercury	0.0003	0.0007
Nickel	1.1	<0.059
Total phosphate (as P)	0.021	0.081
Selenium	0.0019	0.002
Silica	12.57	7.4
Silver	<0.01	<0.01
Sulfate	357.5	48.75
Zinc	1.51	0.09

APPENDIX J

Additional Prohibition of Fossil-Fuel Use
Caused by State Particulate Control Regulations

APPENDIX J. Additional Restrictions Resulting from State
Particulate Regulations

State and Regulation	<u>Sizes of Oil-Fueled Boilers Restricted</u>		<u>Size of Coal-Fueled Boilers Restricted</u>
	<u>Residual</u> (MW)	<u>Distillate</u> (MW)	<u>All Coals</u> (MW)
All states controlled by NSPS: Units > 250 x 10 ⁶ Btu .10 lb PM/10 ⁶ Btu	25-70	25-70	25-100
In addition to NSPS:			
Alabama - range for small size boilers	-	-	10-25
Alaska - all size boilers .10 lb PM/10 ⁶ Btu	-	-	10-25
Arizona - range for small size boilers to 10 x 10 ⁶ Btu	-	-	10-25
California - expressed as concentration limits	-	-	10-25
Connecticut - all size boilers .10 lb PM/10 ⁶ Btu	-	-	10-25
Delaware - H.I. > 1 x 10 ⁶ Btu - .3 lb/10 ⁶ Btu	-	-	10-25

APPENDIX J. Additional Restrictions Resulting from State
Particulate Regulations (Contd.)

State and Regulation	<u>Sizes of Oil-Fueled Boilers Restricted</u>		<u>Size of Coal-Fueled Boilers Restricted</u>
	<u>Residual</u> (MW)	<u>Distillate</u> (MW)	<u>All Coals</u> (MW)
District of Columbia - range for all sizes	10-25 80-100	10-25 80-100	10-25
Georgia - range for small size boilers	-	-	10-25
Illinois - all size boilers .10 lb/10 ⁶ Btu	-	-	10-25
Indiana - boilers < 250 x 10 ⁶ Btu: 0.6 lb/10 ⁶ Btu	-	-	10-25
Iowa - boilers < 250 x 10 ⁶ Btu: 0.6 lb/10 ⁶ Btu	-	-	10-25
Kansas - range for small boilers	-	-	10-25
Kentucky - range for small boilers	-	-	10-25
Louisiana - all sizes 0.6 lb/10 ⁶ Btu	-	-	10-25

APPENDIX J. Additional Restrictions Resulting from State
Particulate Regulations (Contd.)

State and Regulation	Sizes of Oil-Fueled Boilers Restricted		Size of Coal-Fueled Boilers Restricted
	Residual (MW)	Distillate (MW)	All Coals (MW)
Maine - range for small boilers	-	-	10-25
Maryland - expressed as concentration limits	10-25 80-100	10-25 80-100	10-25
Massachusetts - units < 250 x 10 ⁶ Btu: .10 lb/10 ⁶ Btu, units > 250 x 10 ⁶ Btu: .05 lb/10 ⁶ Btu	-	80-100	10-25
Michigan - units burning pulverized coal: .15 lb/10 ³ lb stack gas	-	-	10-25
Minnesota - units < 250 x 10 ⁶ Btu: 0.4 lb/10 ⁶ Btu	-	-	10-25
Mississippi - range for all sizes	-	-	10-25

APPENDIX J. Additional Restrictions Resulting from State
Particulate Regulations (Contd.)

State and Regulation	<u>Sizes of Oil-Fueled Boilers Restricted</u>		<u>Size of Coal-Fueled Boilers Restricted</u>
	<u>Residual</u> (MW)	<u>Distillate</u> (MW)	<u>All Coals</u> (MW)
Missouri - range for all sizes	-	-	10-25
Montana - range small boilers	-	-	10-25
Nevada - range small boilers	-	-	10-25
New Hampshire - range for small boilers	-	-	10-25
New Jersey - range for all fuel-burning equipment	-	-	10-25
New Mexico - liquid fuel: .005 lb/10 ⁶ Btu solid fuel > 250 x 10 ⁶ Btu: .05 lb/10 ⁶ Btu range for small units	10-25 80-100	10-25 80-100	10-25

APPENDIX J. Additional Restrictions Resulting from State
Particulate Regulations (Contd.)

State and Regulation	Sizes of Oil-Fueled Boilers Restricted		Size of Coal-Fueled Boilers Restricted
	Residual (MW)	Distillate (MW)	(All Coals) (MW)
North Carolina - range for all sizes	-	-	-
North Dakota - range for all sizes	-	-	10-25
Ohio - range for all sizes	-	-	10-25
Oklahoma - range for all sizes	-	-	10-25
Oregon - expressed as concentration limit, in ad- dition to NSPS	-	-	10-25
Pennsylvania - range for all sizes	-	-	10-25
Rhode Island - units < 250 x 10 ⁶ Btu: 0.2 lb/10 ⁶ Btu	-	-	10-25

APPENDIX J. Additional Restrictions Resulting from State
Particulate Regulations (Contd.)

State and Regulation	<u>Sizes of Oil-Fueled Boilers Restricted</u>		<u>Size of Coal-Fueled Boilers Restricted</u>
	<u>Residual</u> (MW)	<u>Distillate</u> (MW)	<u>(All Coals)</u> (MW)
South Carolina - units < 1300 x 10 ⁶ Btu: 0.6 lb/10 ⁶ Btu	-	-	10-25
South Dakota - solid fuel boilers: .3 lb/10 ⁶ Btu	-	-	10-25
Tennessee - range for small boilers	-	-	10-25
Washington - expressed as contraction limits	-	-	10-25
West Virginia - power plant regulation: 0.5 (H.I.) lb/hr	-	-	10-25
Wisconsin - units < 250 x 10 ⁶ Btu: 0.15 lb/10 ⁶ Btu	-	-	10-25
Wyoming - all size boilers .10 lb/10 ⁶ Btu	-	-	10-25

APPENDIX K

Additional Prohibition of Fossil Fuel Use Caused
by State SO₂ Regulatory Control

APPENDIX K. Additional Prohibition of Fossil Fuel Use Caused by
State SO₂ Regulatory Control

State and Regulation	Oil Fueled Boilers						Coal Fueled Boilers					Turbines		
	Residual			Distillate			Northwest	Central	N. Appalachia	C. Appalachia	Southwest	Oil		
	.01% (MW)	.5% (MW)	3.0% (MW)	.01% (MW)	.5% (MW)	3.0% (MW)						.1% (MW)	.3% (MW)	.5% (MW)
All states controlled by NSPS: units > 250 x 10 ⁶ Btu coal - 1.2; oil 0.8 lb SO ₂ /10 ⁶ Btu	-	-	25-100	-	-	25-100	25-100	25-100	25-100	25-100	-	No NSPS Emissions from all size turbines using .3% or .5% oil exceed standards for boilers. Tur- bines using .1% oil exceed stan- dards as indicated.		
Additional state regulations:														
Alaska - expressed as con- centration: 500 ppm SO ₂	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	-	-	-	-
Arizona - all size boilers coal - 0.8; oil - 0.8 lb SO ₂ / 10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
California - expressed as 0.5% SO ₂	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
Connecticut - all size boilers, all fuels 0.55 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	.15	-
Delaware - all size boilers distillate oil - .3%	-	-	-	-	10-100	10-25	-	-	-	-	-	-	-	-
District of Columbia - expressed as 0.5% SO ₂	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
Georgia - all size boilers coal - 1.2; oil - 0.8 lb SO ₂ / 10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	-	-	-	-

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APPENDIX K. Additional Prohibition of Fossil Fuel Use Caused by
State SO₂ Regulatory Control (Contd.)

State and Regulation	Oil Fueled Boilers						Coal Fueled Boilers					Turbines		
	Residual			Distillate			Northwest	Central	N. Appalachia	C. Appalachia	Southwest	Oil		
	.01% (MW)	.5% (MW)	3.0%	.01% (MW)	.5% (MW)	3.0%						.1% (MW)	.3% (MW)	.5% (MW)
Hawaii -														
units > 250 x 10 ⁶ Btu	-	-	-	-	-	-	-	-	-	-	-	-	-	-
.5%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
others - 2.0%	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Idaho -														
In addition to NSPS,														
coal - 1.0%	-	-	-	-	-	-	10-25	10-25	10-25	-	-	-	-	-
#1 distillate oil -														
.3%	-	-	10-25	-	10-25	10-25	-	-	-	-	-	-	-	-
#2 distillate oil -														
.5%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
#4-6 residual oil -														
1.75%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Illinois -														
boilers														
< 250 x 10 ⁶ Btu														
coal - 1.8;														
residual oil - 1.0;														
distillate oil - 0.3	-	-	10-25	-	10-100	10-25	10-25	10-25	10-25	-	-	-	-	-
Indiana -														
boilers														
< 250 x 10 ⁶ Btu;														
dependent on heat														
input	-	-	-	-	-	20-25	-	10-25	10-25	-	-	-	-	-
Iowa -														
boilers														
< 250 x 10 ⁶ Btu														
coal - 6.0;														
oil - 2.5 lb SO ₂ /														
10 ⁶ Btu	-	-	10-25	-	-	10-25	-	-	-	-	-	-	-	-
Kentucky -														
< 250 x 10 ⁶ Btu														
dependent on heat														
input	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	-	-	-	-
Maine -														
expressed as 1.5%	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-

APPENDIX K. Additional Prohibition of Fossil Fuel Use Caused by
State SO₂ Regulatory Control (Contd.)

State and Regulation	Oil Fueled Boilers						Coal Fueled Boilers					Turbines		
	Residual			Distillate			Northwest	Central	N. Appalachia	C. Appalachia	Southwest	Oil		
	.01% (MW)	.5% (MW)	3.0%	.01% (MW)	.5% (MW)	3.0%						.1% (MW)	.3% (MW)	.5% (MW)
Maryland -														
residual oil - 1.0%	-	-	10-25	-	-	-	-	-	-	-	-	-	-	-
distillate oil - .3%	-	-	-	-	10-100	-	-	-	-	-	-	-	-	-
coal - 1.0%	-	-	-	-	-	-	10-25	10-25	10-25	-	-	-	-	-
Massachusetts -														
Metro. Boston														
.28 lb S/10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	.15		
Other areas -														
.55 lb S/10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-		
#2 oil - .17 lb S/10 ⁶ Btu	-	10-25	10-25	-	10-100	10-25	-	-	-	-	-	.15-88.7		
Michigan -														
Wayne County														
pulverized coal - 1.0%	-	-	-	-	-	-	10-25	10-25	10-25	-	-	-	-	-
other coal - .5%	-	-	-	-	-	-	10-25	10-25	10-25	10-25	10-100	-	-	-
#1,2 oil - .3%	-	10-100	10-25	-	10-100	10-25	-	-	-	-	-	-	-	-
#4,5,6 oil - .7%	-	-	10-25	-	-	10-25	-	-	-	-	-	-	-	-
Minnesota -														
boilers														
< 250 x 10 ⁶ Btu:														
coal - 4.0														
oil - 2.0 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Mississippi -														
modified units														
< 250 x 10 ⁶ Btu:														
2.4 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Missouri -														
all units														
< 2000 x 10 ⁶ Btu:														
2.0%	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Montana -														
expressed as														
1.0 lb S/10 ⁶ Btu	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Nevada -														
units														
< 250 x 10 ⁶ Btu														
.7 (H.I.) lb S/10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	-	-	-	-

APPENDIX K. Additional Prohibition of Fossil Fuel Use Caused by
State SO₂ Regulatory Control (Contd.)

State and Regulation	Oil Fueled Boilers						Coal Fueled Boilers					Turbines		
	Residual			Distillate			Northwest	Central	N. Appalachia	C. Appalachia	Southwest	Oil		
	.01% (MW)	.5% (MW)	3.0% (MW)	.01% (MW)	.5% (MW)	3.0% (MW)						.1% (MW)	.3% (MW)	.5% (MW)
New Hampshire - In addition to NSPS: coal - 1.5 lb S/10 ⁶ Btu #2 oil - .4% #4 oil - 1.0% #5,6 oil - 1.5%	-	10-100	10-25	-	10-100	10-25	-	-	-	-	-	-	-	-
New Jersey - all units coal #2 oil - .2% #4,5,6 oil - .3%	-	10-100	10-25	-	10-100	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
New Mexico - coal units > 250 x 10 ⁶ Btu - .34 oil units > 1 x 10 ⁶ Btu - .34 1 lb SO ₂ /10 ⁶ Btu	-	-	-	-	-	-	-	-	-	-	25-100	-	-	-
North Carolina - all size boilers 1.6 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	-	-	-	-	-
North Dakota - all size boilers 3.0 lb SO ₂ /10 ⁶ Btu	-	-	-	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Ohio - all size boilers 1.0 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
Oklahoma - all size boilers coal - 1.2, oil - 0.8 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	-	-	-	-
Oregon - boilers 150 < H.I. < 250 x 10 ⁶ Btu coal - 1.6, oil - 1.4 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	-	-	-	-	-

APPENDIX K. Additional Prohibition of Fossil Fuel Use Caused by
State SO₂ Regulatory Control (Contd.)

State and Regulation	Oil Fueled Boilers						Coal Fueled Boilers					Turbines Oil		
	Residual			Distillate			Northwest	Central	N. Appalachia	C. Appalachia	Southwest	.1% S	.3% S	.5% S
	.01% S	.5% S (MW)	3.0% S	.01% S	.5% S (MW)	3.0% S								
Pennsylvania - Beaver, Monongakela Valleys Allegheny County, SE Airbasin Other areas (all limits dependent upon size of boiler)	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
Rhode Island - all sizes 1.1 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
South Carolina - Class I counties units > 10 x 10 ⁶ Btu: 2.3 lb SO ₂ /10 ⁶ Btu Class II counties units < 1000 x 10 ⁶ Btu and all units in Class III counties 3.5 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
South Dakota - all units 3.0 lb SO ₂ /10 ⁶ Btu	-	-	-	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Tennessee - units < 250 x 10 ⁶ Btu Class I counties: 1.6 lb SO ₂ /10 ⁶ Btu Class II counties: 3.0 lb SO ₂ /10 ⁶ Btu Class III counties: 4.0 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	-	-	-	-	-
Texas - In addition to NSPS AQCRs 106,153,210,211, 214,216,218 coal - 3.0; oil - 1.1 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-

APPENDIX K. Additional Prohibition of Fossil Fuel Use Caused by
State SO₂ Regulatory Control (Contd.)

State and Regulation	Oil Fueled Boilers						Coal Fueled Boilers					Turbines		
	Residual			Distillate			Northwest	Central	N. Appalachia	C. Appalachia	Southwest	Oil		
	.01% (MW)	.5% (MW)	3.0%	.01% (MW)	.5% (MW)	3.0%						.1% (MW)	.3% (MW)	.5% (MW)
Vermont - all fuels, all size boilers 2.0%	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
Virginia - In addition to NSPS, AQCR 4.7-1.06 (capacity) 1b SO ₂ /hr Regions not meeting NAAQS - 1.58 (capacity) 1b SO ₂ /hr Other areas - 2.64 (capacity) 1b SO ₂ /hr	-	-	10-25	-	-	10-25	10-25	10-25	10-25	10-25	10-100	-	-	-
Washington - expressed as 1000 ppm SO ₂	-	-	10-25	-	-	10-25	-	10-25	10-25	-	-	-	-	-
West Virginia - State region IV - 1.6 lb SO ₂ /10 ⁶ Btu	-	-	10-25	-	-	10-25	10-25	10-25	10-25	-	-	-	-	-
Wisconsin - AQCR 239 coal boilers < 250 x 10 ⁶ Btu: 1.1 lb SO ₂ /10 ⁶ Btu	-	-	-	-	-	-	10-25	10-25	10-25	10-25	10-25	-	-	-
Wyoming - coal boilers > 250 x 10 ⁶ Btu: 0.2 lb SO ₂ /10 ⁶ Btu	-	-	-	-	-	-	-	-	-	-	25-100	-	-	-

NOTE: Gas boilers unrestricted because of low SO₂ emissions.

APPENDIX L

States with NO_x Standards More Stringent Than NSPS

APPENDIX L. States with NO_x Standards More Stringent Than NSPS

State and Regulation	Oil Fueled Boilers		Coal Fueled Boilers					Gas Fueled Boilers	Turbines		
	Residual	Distillate	Northwest	Central	N. Appalachia	C. Appalachia	Southwest		Oil		Gas
									.01%S	.1%S	
All states controlled by NSPS:											
units > 250 x 10 ⁶ Btu	25-70 ^a 80-100	25-70 ^a 80-100	25-60(SS) 50-100(WB, DB,C)	25-60(SS) 50-100(WB, DB,C)	50-100(WB, DB,C)	50-100(WB, DB,C)	25-60(SS) 50-100(WB, DB,C)	25-70 ^a 80-100	No NSPS	No NSPS	No NSPS
coal - 07; oil 0.3 lb/10 ⁶ Btu									Emissions from all size turbines exceed standards for boilers		
gas - 0.2											
Arizona - all size boilers	10-25	10-25	10-25(SS)	10-25(SS)	-	-	10-25(SS)	-			
Connecticut - units > 5 x 10 ⁶ Btu unless											
by commissioner	10-25	10-25	10-25(SS)	10-25(SS)	-	-	10-25(SS)	-			
District of Columbia - units > 100 x 10 ⁵ Btu	10-25	10-25	10-25(SS)	10-25(SS)	-	-	10-25(SS)	-			
New Mexico - units > 1 x 10 ⁶ Btu (oil)											
units > 250 x 10 ⁶ Btu (coal): .45 lb/10 ⁶ Btu	10-25	10-25	-	-	25-60(SS)	25-60(SS)	-	-			
Oklahoma - units > 50 x 10 ⁶ Btu	10-25	10-25	10-25(SS)	10-25(SS)	-	-	10-25(SS)	-			
South Dakota - all size oil boilers	10-25	10-25	-	-	-	-	-	-			
Wyoming - all size coal boilers											
units > 1 x 10 ⁶ Btu (oil)	10-25	10-25	-	-	-	-	-	-			

^a May exceed limit depending on type of boiler.