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COOPERATIVE EXTENSION
WASHINGTON STATE UNIVERSITY
ENERGY PROGRAM

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State Electricity Restructuring and CHP/DG Development

Introduction

In the U.S. today, commercial and industrial combined heat and power (CHP) and other forms of distributed generation (DG)[1] proceed within a much broader framework of energy production, distribution and regulation. Changes in the broader framework largely determine the opportunities for CHP/DG development, and the shape that it takes.

Certainly the most important change in recent years has been the nationwide movement to restructure the electricity industry away from traditional concepts of regulated monopoly services, and toward competitive markets for electricity and related services.[2] Federal and state actions toward this end have accelerated in the past several years; they continue to be vigorously debated today; and they will evolve substantially over the next decade. This chapter discusses the nature of these changes and their likely impacts on development of CHP/DG by commercial and industrial energy users.

Electricity restructuring impacts CHP/DG in at least two major ways: it transforms the commercial environment in which CHP/DG projects proceed, and it changes laws and regulations that directly apply to these projects. This discussion will address both types of impacts, but it may be helpful to start by recapping the characteristics of CHP/DG that place it in the regulatory arena to begin with.

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[1] There is no universally accepted definition of 'distributed generation' or 'DG.' The 'distributed' component of DG generally refers to small, dispersed technologies (whether grid-connected or not) that are capable of supplementing or substituting for electricity and/or related services provided at the distribution level of electric utility systems. Depending on the utility system and the context, 'small' can mean anything from a few kilowatts for residential applications to 10 megawatts (MW) or more for industrial or large commercial applications, and some argue that DG should include facilities of as much as 50 MW or more connected at the sub-transmission level.

The 'generation' component of DG usually refers to *electricity* generation, but it also includes *co*-generation of electricity and thermal energy (combined heat and power or 'CHP'). CHP facilities can therefore be viewed as a subset of DG, except where they are too large (e.g., hundreds of MW) to be considered 'distributed' in the sense just described.

DG itself can be understood as a subset of 'distributed resources' or 'DR,' a broader term that includes not only distributed *generation*, but other distributed energy resources such as demand-side management, energy storage and energy efficiency measures. Electric industry restructuring described in this chapter most directly affects generation (including cogeneration), rather than demand-side, storage or efficiency resources, so the following discussion focuses primarily on 'CHP/DG' rather than 'DR.'

[2] Electric industry restructuring is often referred to, somewhat confusingly, as 'deregulation.' It is true that many jurisdictions are 'deregulating' the generation component of utility operations, or at least regulating it differently. However, the transmission and distribution components remain subject to regulation, and recent legal and regulatory initiatives have as much to do with those components as with generation. Some changes relevant to CHP/DG have less to do with 'deregulation' of generation *per se* than with other facets of restructuring, so this chapter uses the broader term 'restructuring' in preference to 'deregulation.'

CHP/DG Characteristics Relevant to Regulation

CHP and other types of DG involve conversion of some form of energy input, to a different form or forms of energy output. Energy *inputs* typically take the form of fuels that can be burned, gasified and/or oxidized. They can also take the form of solar, wind, hydro or geothermal energy, which are not 'fuels' in the conventional sense, but are inputs to the energy conversion process. CHP/DG *outputs* are normally electricity and useful thermal energy, but can also include mechanical energy. Different energy inputs are subject to different regulatory regimes and–more importantly for CHP/DG projects–so are different forms of energy outputs.

Energy Inputs to CHP/DG Conversion Process

Among the inputs just listed, natural gas is now the fuel of choice for most CHP and emerging DG technologies, including combined cycle plants, microturbines, fuel cells and advanced internal combustion engines. Other typical CHP/DG fuels include diesel, propane, and increasingly, 'opportunity fuels' such as methane gas from wastewater treatment or landfill operations, or biomass from agricultural crops or forest waste. Each of these fuels (as well as the non-fuel inputs mentioned above) may be subject to environmental and health and safety regulations. However, only natural gas supply traditionally has been subject to comprehensive economic regulation by Federal and state utility regulators.

In recent years, CHP/DG operators have been able to purchase commodity natural gas[3] either directly from their local distribution utility, or from competitive nonutility suppliers, to be delivered through their local distribution utility at regulated delivery rates. Gas purchases from competitive suppliers may provide more flexibility and more opportunities for savings, but like other competitive purchases, they may entail higher risks as well. On the other hand, gas purchases directly from local distribution utilities are generally at regulated rates tied directly to the utility's cost of service (rather than allowed to fluctuate according to their value in competitive markets), and averaged across classes of utility customers (rather than individually negotiated).

Energy Outputs from CHP/DG Conversion Process

Electricity

By definition, CHP and DG plants supply electricity. Electricity supply, in general, is regulated by the Federal government (mainly under the Federal Power Act and the Public Utility Holding Company Act), and by every state (under statutes establishing state public utility commission jurisdiction).

For those considering CHP/DG, it is important to understand that:

- Federal jurisdiction is limited to facilities used for *transmission* (as distinct from local distribution), or *wholesale sales* of electricity, in *interstate commerce*.
- State jurisdiction has focused on *generation* and *local distribution*, and typically is limited to entities that produce and deliver electricity '*to the public*' or '*for public use*' (i.e., the public at large, as distinct from selected customers under individual contracts).

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[3] For many years, natural gas (like electricity) was bought and sold as a 'bundled' product – that is, the costs of the gas itself, its transmission through interstate pipelines, and its delivery through a local utility's distribution lines, were bundled into a single price paid by consumers. In recent years, regulators have 'unbundled' gas supply into its component parts, so that consumers can see and respond to separate charges for the gas itself (the 'commodity'), the cost of transmission, and the cost of local distribution.

These concepts are key to understanding the impact of both traditional regulation and electric restructuring on CHP/DG, and are discussed in more detail later.

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Heating & Cooling

Federal law does not establish a regulatory scheme for thermal output from CHP or other DG plants, but many state laws do. These state laws typically apply to the production and distribution of 'steam' or 'heat.' They are part of the same statutory scheme that confers state regulatory jurisdiction over other utility commodities and services (electricity, natural gas, water, etc.) that are furnished '*to the public*' or '*for public use,*' but not otherwise.

As is true for electricity, whether thermal energy is provided for a 'public use' in most states depends ultimately on whether it is offered for sale to the general public, or to some more circumscribed groups or individuals under negotiated contracts. The application of this standard to specific situations varies considerably from state to state. The important thing is that the use of thermal energy from CHP/DG plants to heat or cool other facilities may render the plant's owners 'public utilities' subject to state regulation, at least where restructuring legislation has not altered the historic jurisdiction of state utility regulators.

Why Regulation Matters for CHP/DG

Whether operating in states with traditional regulatory regimes or states that have adopted restructuring,[4] regulation can profoundly affect CHP/DG projects. For example, under traditional state laws, CHP/DG projects whose economics depend on electric or thermal sales to off-site users or multiple customers, can find themselves 'public utilities,' subject to full-scale commission regulation[5]–including setting of rates, supervision of service, access to company books and records, and control over securities issuances. For CHP/DG owners serving only a few users, the costs and complexity of regulation can overwhelm any possible benefits from operations. On the other hand, some traditional laws exempt cogeneration, renewable or other preferred resource facilities engaged in limited distribution, or whose energy sales are merely

[4] By late 2000, about half the states had adopted restructuring legislation and/or regulations and most others were considering it. (See Figure 1 below.) Various Federal restructuring proposals had been offered in Congress, but none had been adopted.

[5] The same is true under at least one recent restructuring law. New Jersey's February 1999 *Electric Discount and Energy Competition Act* amended NJ R.S. §48:2-13e. to authorize the Board of Public Utilities to regulate thermal sales from cogenerators and district heating systems to residential dwellings if it finds insufficient competition, based on ease of market entry, presence of competitors, and availability of like or substitute services in the geographic area.

‘incidental’ to their main business,[6] and some restructuring laws now exempt all electricity sales directly to retail customers under contract.[7] These kinds of provisions offer CHP/DG owners much greater flexibility to size their projects and to operate them efficiently.

Another example of the significance of regulation for CHP/DG is in the area of supplemental, standby and backup rates charged by utilities to customers employing CHP/DG. These are the rates utilities establish, and regulators approve, for delivering power needed by a customer beyond what its CHP/DG facility produces; for ensuring power during planned maintenance outages of the customer’s generation facility; or for providing emergency power during unplanned outages. Historically, some vertically integrated utilities have discouraged their customers from installing their own generation in competition with utility-owned generation by setting these rates at levels that make it uneconomic for customers to operate CHP/DG facilities. Restructuring removes generation functions from the regulated utility, but these practices nevertheless persist under rate designs that compensate distribution-only utilities based on how much energy flows through their systems (preserving historical disincentives to set supplemental, standby and backup rates that make self-generation feasible and possibly reduce throughput). The relation of such rates to the rates the utility charges non-generating customers, and the standards regulators use to set them, can easily make the difference between an economic CHP/DG project and an uneconomic one.

Even where regulation does not apply directly to CHP/DG projects, it shapes the commercial environment that determines their economic viability and their value. For example, most restructuring initiatives require as part of the transition from regulation to competition, that utility customers pay substantial charges to cover ‘stranded’ generation costs incurred by utilities under regulation, but unrecoverable in competitive markets. During the transition period (which may last for years), customers usually are required to pay these ‘stranded cost’ charges to the utility even if they choose to install their own, more efficient CHP/DG solutions–nullifying any economic advantage from CHP/DG installations, and removing any commercial incentive to pursue them.

These are just a few examples of how regulation impacts CHP/DG deployment. These and other examples will be discussed in more detail in the following section. The important point here is that regulation directly impacts not only the sizing and configuration of CHP/DG installations, but their economic viability relative to competing energy solutions.

Traditional Regulatory Framework

Monopoly Providers & Captive Ratepayers

The ‘traditional’ regulatory framework described here refers to the structure of law and regulation applied to U.S. electric utilities from the 1930s into the 1990s. It remains in place in states that have not restructured their electric industry (about half of the states), and elements of it remain even in states that have restructured or are in the process of doing so.

The traditional framework rests on the theory that electric utilities are ‘natural monopolies.’ To economists, this means that a single firm can supply the market with electricity at a lower cost than could several competing firms, by capturing economies of scale unavailable to smaller

[6] See references at footnote 10.
[7] E.g., California Public Utilities Code §§216(i) & 331(c), added by California’s 1996 restructuring law (AB 1890).

producers. This was generally considered to be the case when utilities were vertically integrated[8], generation investment represented their greatest cost, and larger and larger generating technologies continued to deliver economies of scale (circumstances that no longer exist for most utilities).

Under these conditions, states have been willing to sanction monopoly electricity providers. In return, and in order to protect the public from monopoly abuses, state law has defined these providers as 'public utilities' subject to comprehensive regulation of their rates and services by state utility commissions.

The state-sanctioned monopoly typically takes the form of an exclusive right to provide electric service within a defined geographic territory. Within that territory, *other electricity providers cannot offer competing services*, and *consumers cannot access electricity from any provider other than the utility*.[9] The utility's exclusive right to serve does not preclude others from generating power in the territory, but it generally does preclude them from selling it to others.

Many states provide exceptions to these basic propositions, but they are narrow ones. They may permit limited distribution or sale of electricity from preferred generation resources such as cogeneration, landfill gas, biomass, or other nonconventional power sources (or of heat from renewables such as solar or geothermal). Often these exceptions are limited to furnishing power for the producer's own use or that of its tenants or affiliates, or for use by one or two others on contiguous private property. Occasionally they permit sales of surplus power or heat, incidental to the supplier's main business.[10]

Apart from these limited exceptions, however, the characteristics of traditional electricity regulation that most directly impact CHP/DG are as follows:

Vertically integrated utilities provide monopoly electricity services within defined geographic territories;

- Other providers cannot compete to sell or deliver electricity in those territories;
- Consumers cannot choose an electricity supplier other than the utility; and
- Regulators set utility rates, which are based on utility costs to provide the service rather than on its value to customers.

[8] 'Vertical integration,' in which the utility owns and operates generation, transmission, and distribution assets, has been by far the dominant paradigm for investor-owned utilities in the U.S. until recent restructuring efforts, which view generation as a competitive function that can and should be separated from monopoly transmission and distribution functions.
[9] Subject to narrow exceptions discussed below.
[10] For more detailed discussion of such provisions, see Nimmons, J., et al., *Legal, Regulatory & Institutional Issues Facing Distributed Resources Development* (National Renewable Energy Laboratory, 1996), pp. 72-87; Bloomquist, R., Nimmons, J. and Rafferty, K., *District Heating Development Guide* (Washington State Energy Office, 1987), pp. 64-76.

Emerging Regulatory Framework

Competitive Generation Markets & Customer Choice

The Beginnings of Competition: PURPA Cogenerators and Small Power Producers

The first significant change in the traditional regulatory framework resulted from the 'energy crises' of the 1970s. Responding to mid-1970s' oil shortages, in 1978 the U.S. Congress enacted the Public Utility Regulatory Policies Act, commonly known as 'PURPA.'[11] PURPA authorized and encouraged the beginnings of competition in electricity supply by removing important barriers to the development of cogeneration facilities meeting certain operating and efficiency standards, and of small power production facilities using renewable resources.[12]

To open up markets for electricity from these sources, PURPA required electric utilities to purchase their output at the utility's 'avoided cost'–i.e., the cost the utility otherwise would have incurred to produce the power itself or to buy it from others. To prevent utility discrimination against emerging competitive cogenerators and renewable resource suppliers, PURPA also required utilities to provide them with backup, maintenance and supplemental power on the same terms the utilities charged customers without their own generation. Through these mechanisms, PURPA helped create a robust cogeneration and renewable resource industry. But the competition it spawned was limited to *wholesale* power sales into the utilities' grids: *retail* power sales to end-users remained the exclusive province of state-regulated investor-owned utilities and self-regulated municipal utilities, and end-users remained dependent on monopoly providers for electricity services.

When PURPA was enacted, it appeared that oil prices would continue to rise dramatically, and that the cost of power generation that relied largely on oil and gas would continue to spiral upward, making it attractive for cogenerators and renewables producers to sell to utilities at the utilities' avoided costs. But oil and gas prices–and thus utility avoided costs–began to fall by the mid-1980s. By the early 1990s, the returns available from wholesale power sales at utility avoided costs were no longer sufficient to support investment in cogeneration or small renewables projects in many cases. PURPA remains on the books for now, despite increasing calls for its repeal. Nonetheless, the realities of low avoided cost payments and changing energy markets have rendered it a dead letter in many areas of the country.

Broadening Wholesale Competition: The 1992 Energy Policy Act and IPPs

By the late 1980s, investor interest had shifted toward large (often 400 MW or greater) combined cycle, electric–only plants owned by nonutility, independent power producers ('IPPs'). These plants did not qualify as PURPA cogeneration or small power production facilities and so were not entitled to PURPA's avoided cost or other benefits. However, they typically produced cheaper power that could compete favorably with utility-owned generation in wholesale markets.

The emergence of low-cost power from these non-utility IPPs in the late 1980s gave further impetus to the idea that competition could lead to lower-cost electric generation, and contributed to Congressional enactment of the Energy Policy Act of 1992.[13] The 1992 Act opened the door further to wholesale competition by requiring transmission-owning utilities to provide nonutility generators with open access to their interstate transmission systems for wholesale power sales,

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[11] See U.S. House of Representatives Conference Report No. 95-1750 accompanying H.R. 4018, October 10, 1978.
[12] *PURPA* §210; 16 USC Sec. 824a-3.
[13] See U.S. House of Representatives Conference Report 102-1018 accompanying H.R. 776; October 5, 1992.

on terms and at prices comparable to those available to the utilities' own generation units.[14] These principles have since been implemented through orders of the Federal Energy Regulatory Commission (FERC), and nondiscriminatory open access to transmission became available in practice to large nonutility generators beginning in 1996.

Moving Toward Retail Competition: State Electricity Restructuring Initiatives
As the FERC moved to implement wholesale competition under the 1992 Act, state utility commissions and legislatures with jurisdiction over utility *generation*, *retail* sales and *local distribution* systems began to consider competitive models for those activities as well. State efforts to restructure the electric industry proceed from the premise that the generation component of electric service is no longer a 'natural monopoly,' and no longer needs or justifies special regulatory protections.

Some economists argued from the start that electric utilities were not really natural monopolies. In the mainstream, however, there was little disagreement that all three segments of the industry, and thus the industry as a whole, were a natural monopoly during its first few decades. By the 1970s, many argued that economies of scale in power generation had come to an end, while transmission and distribution remained natural monopolies. Hence, the simple reasoning went, generation need no longer be regulated, although regulation of the other two stages of the industry should continue. Most observers now believe that the generation stage of the industry has lost enough of its economies of scale to qualify for deregulation[15]

Stated differently, the argument is that the justification for state-sanctioned generation monopolies has disappeared. Restructuring therefore aims to eliminate special monopoly protections[16] and resultant regulatory controls[17] to allow electric generators to compete for retail customers, and customers to choose their generation suppliers and services.

Achieving these objectives has turned out to be a complex undertaking for a number of reasons. First, most U.S. investor-owned utilities have been vertically integrated: they own and operate generation facilities, high-voltage transmission systems to transport power over long distances, and lower-voltage local distribution networks to serve end-use customers. To make generation competitive while continuing to regulate transmission and distribution, *generation must somehow be separated* from the other two utility functions (through asset divestiture or structural separation into a different company).

[14] The Federal Power Act (FPA) confers federal regulatory jurisdiction over facilities for *transmission* and *wholesale sales* of power in *interstate commerce*, but not over facilities used in '*local distribution*' or in *retail sales* directly to end-users, which are subject to the jurisdiction of state legislatures and utility commissions. 16 U.S.C. §824(b).
[15] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era* (Public Utilities Reports, Inc., 1997), p. 4.
[16] E.g., exclusive service territories that bar entry to competing generators.
[17] E.g., commission ratesetting based on utility costs, to protect against monopoly pricing abuses.

Second, to the extent that allowing generation competition deprives utilities of earnings fairly expected on generation assets they built to meet regulatory obligations to serve the public, then *utilities must somehow be compensated for 'stranded' generation costs* that become unrecoverable in competitive markets.

Third, separating the ownership and operation of generation from that of transmission and distribution does not change the physical reality that generation output must still be delivered to energy consumers. Where the generating facility is physically located on the site where its output is used, delivery is not an issue. But most existing generation in the U.S. consists of large central station plants remote from the populations they serve, and most electricity delivery occurs across utility-owned transmission and distribution systems. Even local generation facilities situated across town or down the street from their end-users may find it most efficient to deliver electricity through utility-owned and controlled wires systems. In either case, most *generators need open access to wires delivery systems* to reach competitive markets for their services. Consumers who choose to rely on competitive generators may likewise need continuing access to utility wires to supplement, back up, and/or permit routine maintenance of their generation supply.

A fourth consideration for restructuring is that regulated utilities have long served as institutional vehicles to implement energy policies favoring conservation, energy efficiency, and renewable resources.

Unrestrained competition among generators will likely disadvantage some of these higher-cost emerging technologies in the short run. Restructuring efforts have recognized that *emerging efficiency and environmental technologies warrant continuing support*, and most legislation has retained some measures to encourage them.

Finally, although restructuring legislation usually deals comprehensively with the issues just outlined, it may not fully reconcile or conform them with existing state utility laws. This leaves room for interpretation and confusion as to the relationship of earlier laws still on the books to new restructuring schemes.

Status of State Electricity Restructuring

Different Strokes for Different States

As noted above, U.S. interest in electricity restructuring at the state level began in earnest in the mid-1990s. In 1994, California's regulatory commission staff published one of the first wide-ranging discussions of restructuring issues, followed by a more refined version the next year.[18] Other states' regulators initiated investigations beginning at about the same time, and the first legislation to implement restructuring (also referred to as 'deregulation' or 'retail choice') emerged in 1996.[19]

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[18] Popularly known as the 'Yellow Book' and the 'Blue Book.'

[19] See New Hampshire HB 1392 (5/21/96), Rhode Island HB 8124 (8/7/96), and California AB 1890 (9/24/96).

Only four years later, about half the states have enacted some form of electricity restructuring legislation. Most of the others are considering it or in the process of enacting it, or their commissions have issued administrative orders addressing restructuring. The following chart summarizes the status of state restructuring efforts as of late 2000.

Although certain basic features are common among states that have adopted restructuring legislation, the legislation varies greatly in scope and complexity.[20] Legislative provisions are often subject to state utility commission interpretation and implementation, which also varies

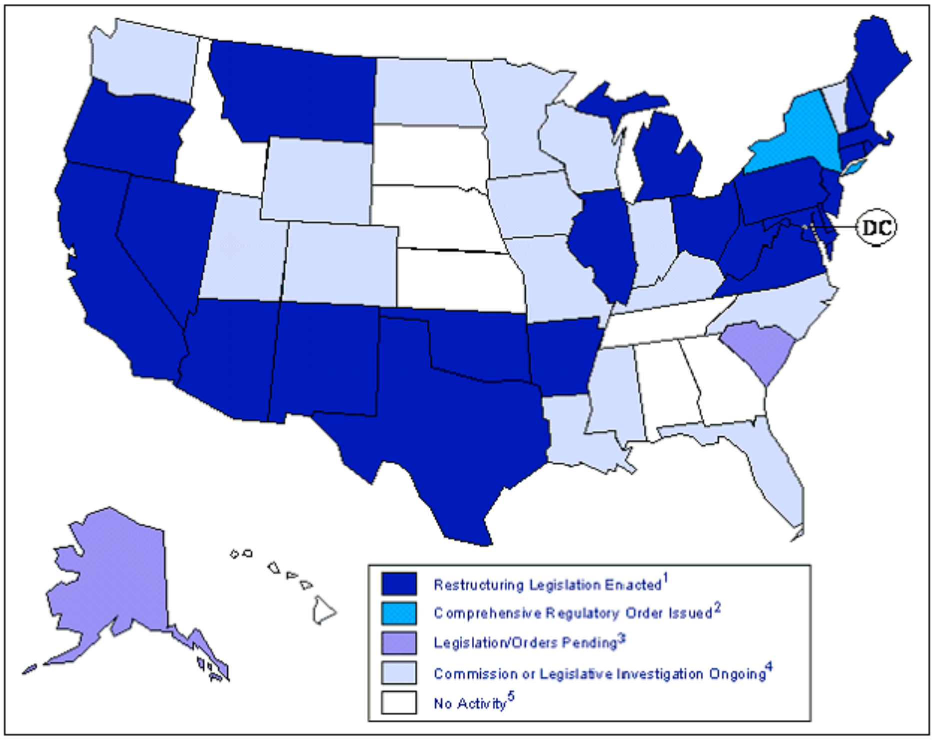

Figure 1. Status of State Electric Industry Restructuring Activity
Source: Energy Information Administration,
http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.[21]

[20] For example, New Hampshire's 1996 legislation is about 6 pages long, Illinois' 1997 law runs 43 pages, California's AB 1890 comprises 70 pages, and New Jersey's 1999 law totals about 90 pages.

[21] States listed under each category in the map are:

1 Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia.

2 New York.

3 Alaska and South Carolina.

4 Colorado, Florida, Indiana, Iowa, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin, and Wyoming.

5 Alabama, Georgia, Hawaii, Idaho, Kansas, Nebraska, South Dakota, and Tennessee.

The Energy Information Administration website cited is a helpful central source of information on state electricity restructuring, containing links to legislation and administrative actions and utility sites in each state. Other useful sites include http://www.spratley.com/leap/ and http://www.naruc.org/Stateweb.htm.

widely by state. In addition, many of the new provisions have yet to be fully implemented, and energy markets are changing rapidly as fuel prices change, new participants and technologies emerge, and competition takes hold. For these reasons, the impacts of restructuring on CHP/DG development are anything but uniform or static: they will vary considerably by locale and over time as new rules are adopted and implemented. Still, it is possible to identify general topics common to many restructuring schemes that are likely to impact CHP/DG decisions, and to describe some of their implications for future CHP/DG development.

Key Restructuring Issues Affecting CHP/DG

When Restructuring Starts, How it Works, and its Impact on Rates
Restructuring initiatives generally focus on broad issues involved in transitioning from regulation to competition. To the extent they address CHP/DG, it is only as one facet of a larger competitive generation market, currently dominated by multi-megawatt merchant plants designed to sell power into the transmission grid, or through it to the utilities' largest customers.

Until now, at least, most CHP/DG plants in the U.S. have been designed mainly to meet the needs of their site or site host. They have been less oriented toward supplying power or heat to other users, in part because traditional regulation has usually made those options difficult, costly and impractical. So long as CHP/DG projects consume all of their electric and thermal outputs on-site; do not distribute or sell to persons other than the facility owner; and do not rely heavily on the grid for backup, supplemental, or maintenance power, restructuring will impact them mainly through its effect on energy markets and prices generally. However, to the extent that competitive generation and access to distribution expands opportunities for community energy systems, district heating and cooling, or retail sales of electricity and thermal products, restructuring can more directly influence CHP/DG choices.

Table 1 lists key restructuring issues, addressed by recent state initiatives, that impact CHP/DG by transforming its overall commercial environment and/or by direct application to CHP/DG projects. The issues are listed by the subsection number below where each is more fully discussed.

Implementation of Retail Choice
As indicated previously, states are in various stages of considering and adopting restructuring initiatives that allow retail electricity customers to choose their generation suppliers. Among the states that have so far adopted legislation or comparable administrative orders, implementation dates vary widely, from as early as 1998 to as late as 2004. So too do approaches to phasing in choice for different classes of customers as each state transitions toward full competition. Moreover, phase-in dates for retail choice have often been delayed by legal challenges over other matters integral to state restructuring schemes (most often the treatment of utility stranded generation costs).[22]

[22] Examples include New Hampshire, where retail access originally scheduled to begin by January 1, 1998, was delayed nearly three years by federal court challenges to the disallowance of 'stranded costs' claimed by Public Service of New Hampshire; and Arizona, where competition originally scheduled to begin in January 1999 has been delayed over challenges to its utilities' restructuring settlements.

Table 1
Key Restructuring Issues Affecting CHP/DG

Issue	Description
5.1 Implementation of retail choice	When will end-users be free to choose competitive generation suppliers, including CHP/DG providers?
5.2 Separation of utility generation functions & divestiture of assets	Must utilities separate competitive generation from regulated delivery functions, and must they divest their generating assets to achieve that?
5.3 Open access & comparability for utility distribution services	Can nonutility generators and end-users access utility distribution systems for their own transactions, with reasonable prices and delivery terms?
5.4 Utility's obligation to serve & its status as 'default provider'	Will utilities retain their traditional obligation to serve any customer who applies for service, and what services will they be obligated to provide? Will utilities remain responsible to serve customers who do not choose other generation suppliers?
5.5 Liability for transition charges	Will utilities be compensated for generation costs that become uneconomic in competitive markets? If so, who will pay and under what conditions?
5.6 Special treatment for CHP/DG, renewables & other technologies	Does restructuring legislation treat users of CHP/DG any differently than other energy users or other utility customers, and, if so, in what ways?
5.7 Transitional rate reductions & post-transition rates	How will restructuring impact utility rates during the transition to fully competitive retail generation markets, and once the transition ends?

Some states have set a single date by which all customers of regulated utilities[23] are able to choose their generation suppliers, and by which distribution access and other restructuring elements are to be in place.[24] Other states have phased in customer choice over periods of months or years, usually beginning with larger industrial and commercial customers and phasing

[23] Much state restructuring legislation focuses primarily on investor-owned utilities regulated by statewide public utility commissions. Most such commissions have limited or no jurisdiction over publicly-owned, municipal and cooperative utilities, which are self-regulating under their own state enabling legislation, separate from that which subjects investor-owned utilities to commission supervision.
[24] For example, California regulators set March 1, 1998, as the date when all customers served by the state's investor-owned utilities were entitled to choose among competing generation suppliers. Michigan's legislation set January 1, 2002, as that date for customers of its two largest investor-owned utilities. [Michigan 90th Legislature, Public Act No. 141, June 5, 2000; §10a.(1)]

in residential customers over time.[25] Still others have phased in competition by allowing a fixed percentage of each utility customer class to choose their suppliers in each of several time periods.[26]

Since states vary so widely in their implementation approaches and their schedules often change as they transition toward competition, it is impossible to generalize much further than this. The best source of current information on individual states' implementation schedules is the worldwide web, where a number of electricity restructuring sites continually update this information.

Separation of Utility Generation Functions & Divestiture of Assets

Restructuring initiatives recognize that utilities which continue to own, operate and derive revenues from their own generation, face inherent conflicts of interest in providing distribution services to nonutility generators competing for the utilities' once-captive customers. Restructuring schemes seek to eliminate or neutralize such conflicts through several mechanisms. One mechanism, discussed in this section, is to eliminate conflicts by removing their source–i.e., by removing generation functions from the utility through regulatory treatment, corporate reorganization, or divestiture of generation assets, and allowing the utility to retain only its delivery functions (distribution and, in some cases, transmission). Other mechanisms, discussed in the section below, attempt to ensure that those delivery functions are carried out in ways that do not hinder or discriminate against nonutility generators competing with whatever generation functions the utility may retain.

States have followed several approaches to separate generation from other functions of a regulated utility. One is for commissions to allow the utility to retain generation assets and operations within the regulated utility company, but not to consider generation-related costs or revenues when setting utility rates. This approach (referred to as '*functional*' separation) effectively treats utility-owned generation as a competitive, 'nonutility' business within the utility, not supported by utility ratepayers, and not subject to commission-set earnings limits.

Another approach ('*structural*' separation) is to require that generation assets and operations be transferred to a legally distinct corporate entity, sometimes a subsidiary but more often an affiliated corporation under the utility's parent holding company (if it has one), with financial implications similar to those just described. Although legally speaking this amounts to divestiture of utility generation assets, the term divestiture is perhaps more commonly used to describe situations where the utility sells or transfers such assets to an unrelated third party.

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[25] Illinois, for example, required its electric utilities to provide 'delivery services' for competitive generation by *October 1999* for nonresidential customers with at least 4 MW of monthly demand or whose annual use comprised 33% of kWh sales to their customer class, and to multi-site commercial customers with at least 9.5 MW; by *October 2000* for eligible government customers; by *June 2000* for customers in certain Standard Industrial Classifications; by *January 2001* for all remaining nonresidential customers; and by *May 2002* for all residential customers. (See 220 ILCS §5/16-104.) New York's Public Service Commission has phased in retail access differently for each of its seven major jurisdictional utilities over periods beginning in mid-1998 and ranging from one to three years. (See schedule summary at http://www.eia.doe.gov/cneaf/electricity/chg_str/retail.html#NY.)

[26] Pennsylvania law, for instance, establishes retail choice on a first-come first-served basis for customers comprising up to 33% of the peak load of each customer class by January 1, 1999; up to 66% by January 1, 2000; and up to 100% of all distribution customers by January 1, 2001. [66 Pa. C.S. §2806(b).] Arizona's Commission was authorized to open utility territories to competitive generation by January 1999 for at least 20% of the utilities' 1995 retail load, with 15% of that reserved for residential customers, and to open the utilities' entire territory to competition by January 2001. [ARS §40-202-B.1.]

Restructuring legislation commonly requires or at least permits functional separation, and sometimes structural separation through divestiture of generation assets. Arizona law, for example, declares state policy favoring competitive generation and confirms its commission's authority to "not consider the profits or losses associated with electric generation service when regulating electric distribution service."[27] Illinois authorizes its commission to "adopt rules requiring functional separation between the generation services and the delivery services" of Illinois utilities, and "between an electric utility's competitive and non-competitive services."[28] New Hampshire law, couched in broad policy terms, offers this additional guidance:

> Generation services should be subject to market competition and minimal economic regulation and *at least functionally separated from transmission and distribution services* which should remain regulated for the foreseeable future. However*, distribution service companies should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs*.[29]

States also differ with respect to structural separation or divestiture. For example, Pennsylvania's commission "may permit, but shall not require, an electric utility to divest itself of facilities or to reorganize its corporate structure."[30] New Jersey's commission can require electric utilities either to functionally separate non-competitive business functions from competitive generation services, or to divest some or all of their generation assets and operations to unaffiliated companies.[31] Michigan goes further by requiring an electric utility that controls more than 30 percent of the generating capacity in a relevant market to either divest its excess capacity, or to contract to sell it to a nonretail purchaser or transfer it to an independent, unaffiliated brokering trustee for at least a 5-year term.[32]

California law illustrates another approach to the question of separating generation from regulated distribution activities. It provides that if a public utility wants to retain ownership of generation assets within the distribution utility, then it must demonstrate to the commission's satisfaction that this would be 'consistent with the public interest' and would not 'confer undue competitive advantage.'[33] This approach places the burden squarely on the utility to overcome

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[27] ARS §40-202-B.8.
[28] 220 ILCS §16-119A.(b).
[29] NHRS §374-F:3-III; emphasis added. This provision is unusual in explicitly mentioning distributed resources, and also in establishing a legislative policy that regulated distribution utilities can own such resources to minimize system costs.
[30] 66 Pa. C.S. 2804(5).
[31] See *Electric Discount and Energy Competition Act* (A-10/S5, 208th N.J. Legislature), February 1999; §11a; see also §8h.
[32] Michigan 90th Legislature, Public Act No. 141 (Enrolled Senate Bill 937), June 5, 2000; §10f(1).
[33] California Public Utilities Code §377.

anticompetitive concerns. But whatever approach is used, the intent of all of them is to reduce or eliminate any incentive the utility might otherwise have to discriminate against competing generators and in favor any generation it might retain.

Open Access and Comparability for Utility Distribution Services

Unless a user's generation supply is located on its own site, at least two additional conditions need to be met to ensure meaningful competition. First, users and competitive generation providers need legal and physical access to distribution lines running to and from user sites so that electricity and related services can be delivered. Second, they need some assurance that the utility in control of those lines will provide and price its distribution services in ways that do not discriminate against users who choose to take generation from other sources, or against nonutility suppliers who provide that generation.

To address these needs, restructuring initiatives typically require utilities to provide *open access* to their distribution systems for nonutility suppliers and end-users, and to ensure *comparability*–i.e., delivery service at prices and on terms comparable to those enjoyed by any generation units retained by the distribution utility itself.

Open Access. The specificity and scope of open access requirements differ among states. Restructuring laws often provide only broad policy guidance on this topic, leaving it to state utility commissions and individual utilities to come up with methods to implement open access.[34] However, some legislation is more specific. Pennsylvania directs its commission to:

> …allow customers to choose among electric generation suppliers in a competitive generation market through direct access. Customers should be able to choose among alternatives such as firm and interruptible service, flexible pricing and alternate generation sources, including reasonable and fair opportunities to self-

[34] New Hampshire, New Jersey, Illinois, and California restructuring laws are examples of this approach. New Hampshire's 1996 statute simply states that "Non-discriminatory open access to the electric system for wholesale and retail transactions should be promoted. Comparability should be assured for generators competing with affiliates of groups supplying transmission and distribution services. The commission should monitor companies providing transmission or distribution services and take necessary measures to ensure that no supplier has an unfair advantage in offering and pricing such services." [New Hampshire Revised Statutes, Chapter 374F, §3-IV.]
Similarly, New Jersey's 1999 statute declares only that "The traditional retail monopoly …for electric power generation and supply services should be eliminated, so that all New Jersey energy consumers will be afforded the opportunity to access the competitive market … and to select the electric power supplier of their choice." It goes on to authorize the Board of Public Utilities to direct New Jersey's electric utilities to submit restructuring filings that include mechanisms to implement retail choice. [*Electric Discount and Energy Competition Act* (A-10/S5, 208th New Jersey Legislature, February 1999, §§2.b.(4) and 5.b.] Illinois' 1997 law similarly directs each of the state's electric utilities to submit to the Illinois Commerce Commission a detailed implementation plan for 'delivery services' needed to transport nonutility-generated electricity to retail customers. [220 ILCS §5/16-105.] California's 1996 restructuring law is somewhat more specific in stating that "In order to achieve meaningful wholesale and retail competition in the electric generation market, it is essential to …[p]rovide customers and suppliers with open, nondiscriminatory, and comparable access to transmission and distribution systems." [California Public Utilities Code §330(k), to be implemented by the Public Utilities Commission pursuant to §365.] Unlike many restructuring statutes, California's is explicit in mandating open, nondiscriminatory, and comparable access not only for generation suppliers, but for end-use *customers* – presumably including those with on-site generation or CHP that may not be eligible for backup, supplemental, or maintenance power on such terms under PURPA, but will now be entitled to those services under California law.

generate and interconnect. These alternatives may be provided by different electric generation suppliers.[35]

Michigan's June 2000 restructuring law offers additional specification in providing that:

> a) An electric utility shall take all necessary steps to ensure that merchant plants [nonutility generation plants over 100 kW] are connected to the transmission and distribution systems within their [*sic*] operational control. If the commission finds … that an electric utility has prevented or unduly delayed the ability of the plant to connect to the facilities of the utility, the commission shall order remedies designed to make whole the merchant plant, including … reasonable attorney fees [and] may also order fines of not more than $50,000.00 per day.
>
> b) The commission shall establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities. The standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations. The standards shall be consistent with generally accepted industry practices and guidelines and shall be established to ensure the reliability of electric service and the safety of customers, utility employees, and the general public. The merchant plant will be responsible for all costs associated with the interconnection unless the commission has otherwise allocated the costs and provided for cost recovery.[36]

<u>Comparability.</u> The requirement that electric utilities not only provide distribution access, but provide it on terms comparable to those available to their own generating units, is also a common feature of these laws. A typical example is Pennsylvania's 1995 law directing its commission to require the state's utilities to:

> provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, *on rates, terms of access and conditions that are comparable to the utility's own use of its system.*[37]

This and similar statutes in other states mean that utilities that retain their own generation facilities and deliver their output to customers through their distribution systems, cannot systematically make it easier for their own generation facilities to connect with their systems, or cheaper to transport their power, than it is for their nonutility competitors to do the same thing.

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[35] 66 Pa. C.S. 2804(2).

[36] Michigan 90th Legislature, Public Act No. 141 (Enrolled Senate Bill 937), June 5, 2000; §10e.

[37] 66 Pa. C.S. §2804(6); emphasis added. Note also the New Hampshire and California statutes quoted at footnote 35, above.

What's sauce for the goose must be sauce for the gander, and CHP/DG facilities exporting electricity to offsite customers through utility distribution systems are entitled to the same treatment as utility-owned generation facilities.

Utility's Obligation to Serve and its Status as 'Default Provider'

Traditional regulation grants utilities the status of monopoly providers within exclusive geographic territories, in return for which utilities assume a legal *obligation to serve* anyone who applies for service within the territory. By sanctioning competition in what historically have been monopoly territories, restructuring raises questions as to whether the utility will have any continuing obligation to serve customers who are free to choose other suppliers, and what the nature of that obligation will be. What services might it be obligated to provide? Will it continue to be the provider of last resort ('default provider') for those who cannot or do not choose other suppliers? For CHP/DG facilities, will the distribution utility continue to be available and responsible to provide power to supplement their production, to supply emergency backup, and/or to serve load during scheduled maintenance outages?

Restructuring initiatives typically address the existence and nature of the utility's continuing obligation to serve, although specifics vary as they do on other key issues. One approach is simply to extend the utility's normal obligation to serve for a specified time, subject to later commission review. New Jersey, for example, requires electric utilities to continue to provide "basic generation service" (i.e., regulated service for customers who do not or cannot obtain service from alternative suppliers) for at least three years after the start of retail choice, and until the commission finds that this is no longer necessary or in the public interest.[38]

Another approach is to continue the utility's traditional obligation to serve during the early phases of the transition to competition, but to narrow or modify that obligation as competitive markets develop. Pennsylvania's law is illustrative:

> *Obligation To Serve*.—An electric distribution company's obligation to provide electric service following implementation of restructuring and the choice of alternative generation by a customer is revised as follows:
>
> (1) While an electric distribution company collects [a transition charge] or until 100% of its customers have choice, whichever is longer, the electric distribution company shall continue to have the *full obligation to serve*, including the *connection* of customers, the *delivery* of electric energy and the *production or acquisition* of electric energy for customers.
> (2) At the end of the transition period, the Commission shall promulgate regulations to define the electric distribution company's obligation to *connect* and *deliver* and *acquire* electricity under paragraph (3) ...
> (3) If a customer contracts for electric energy and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or Commission-approved alternative supplier shall acquire electric energy at prevailing market prices to serve that customer and shall recover fully all reasonable costs.
> (4) If a customer that chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local

[38] *Electric Discount and Energy Competition Act* (A-10/S5, 208th New Jersey Legislature, February 1999, §§9.a.

> distribution company shall treat that customer exactly as it would any new applicant for energy service.[39]

Other states also recognize the changing nature of the distribution utility's obligation to serve, and redefine it to be more consistent with the utility's evolving role to facilitate competitive generation markets. New Hampshire's statute, for example, clearly states that 'A utility providing distribution services must have an obligation to *connect all customers in its service territory to the distribution system*," but it does not establish a similar obligation to produce, acquire or deliver power to customers.[40] Illinois generally obligates electric utilities to continue offering the regulated services they offered prior to restructuring until those services are declared competitive, but it also obligates them to offer regulated delivery services, certain power purchase options, and real-time (hourly or periodic) pricing consistent with customer needs in competitive markets.[41]

Special obligations to serve are often established for residential and smaller commercial customers expected to possess less leverage than larger customers in competitive markets. In Illinois, for example, utilities must continue to offer 'bundled' services to these customers, albeit at market-based rather than cost-based prices for components (notably generation) that the Illinois commission declares competitive.[42] Other states require their regulated utilities to act as 'the supplier of last resort' for generation services for low-usage customers unable to obtain service from other generation suppliers.[43]

Liability for Transition Charges

To fulfill their traditional legal obligation to serve customers, vertically integrated utilities historically made large investments in central station generating plants designed to serve the public. Traditional regulation virtually assured them recovery of those investments by barring competition within their service territories, and setting cost-based rates designed to yield a fair return on their investments. Restructuring threatens recovery of utility generation investments by removing traditional barriers to competition, and by allowing market forces to determine investment returns. These changes undermine utility expectations of recovering prudently incurred costs, and arguably violate the regulatory compact underlying historic generation investments.

Restructuring legislation recognizes this, and uniformly establishes mechanisms to compensate utilities for generation costs that become uneconomic and unrecoverable (i.e., '*stranded*') in competitive markets. These mechanisms are referred to as 'stranded cost' or 'competitive transition' charges.[44] They take various forms, but their effect is *to impose additional charges on energy consumers who continue to take any form of service from the utility*. These charges may persist until a specific date established by state legislation, or until the utility recovers its historic generation costs, or until the transition to full competition is complete.

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[39] 66 Pa. C.S. §2807(e); emphasis added.
[40] NHRS §374-F:3-V.
[41] 220 ILCS §5/16-103.
[42] Id.
[43] See, e.g., Arizona's legislation at ARS §4-202-B.5.
[44] 'Transition charges' include stranded generation costs, but may also include other components such as benefits for utility employees displaced by competition; charges for research and development of promising new energy technologies; initiatives supporting renewables, energy efficiency, or the environment; or low-income energy assistance.

California law on stranded generation costs typifies the basic principle adopted by many states:

> The commission shall identify and determine those costs and categories of costs for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts … that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market [and these] uneconomic costs shall be recovered from *all customers* on a *nonbypassable* basis ...[45]

Some states' laws are more narrowly circumscribed, balancing utility stranded cost recovery against customer interests in minimizing rates and requiring utilities to mitigate stranded generation investment. New Hampshire law, for example, is explicit on this point, emphasizing that "utilities have had and continue to have an obligation to take all reasonable measures to mitigate stranded costs" (including reducing expenses, renegotiating power purchase contracts, refinancing debt, and writing off some uneconomic assets).[46] Some states expressly permit, but do not require, utilities to impose transition costs.[47]

Consistent with the California language quoted above, transition or stranded cost charges typically apply to all utility customers who remain connected to the distribution system, and they are usually 'nonbypassable.' This means that customers who remain connected *cannot avoid or reduce these charges by installing their own generation* or buying it from nonutility sources. Methods for calculating transition charges vary widely, but the end result can amount to a very substantial component of rates charged to customers during the transition period.

For users considering CHP/DG, the important thing is to be aware that *nonbypassable and potentially sizeable transition charges will offset–and may exceed–anticipated cost savings, possibly rendering projects uneconomic for as long as those charges remain in place*. On the other hand, some states have expressly exempted certain types of CHP/DG facilities and uses from transition cost charges, as discussed in the next section.

Special Treatment for CHP/DG, Renewables, and Other Technologies
Many state restructuring laws provide special treatment for certain on-site or self-service generation (including cogeneration or CHP), and/or for generation employing renewable resources. Such treatment may take the form of exemptions from transition charges or from public utility regulation that could otherwise apply, and may include other provisions favoring specified types of CHP/DG.

<u>Transition Charge Exemptions.</u> Exemptions from transition charges are common for self-generation or cogeneration, and/or for renewables and other preferred resources. California's 1996 restructuring law, for example, affirmed the state's policy to encourage cogeneration as 'an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply.' It directed California's utility commission to exempt from transition charges load served on-site or over-the-fence by certain cogeneration equipment that was operational or committed to by specified dates, as well as load served by some emergency

[45] California Public Utilities Code §367.
[46] NHRS §374-F:3(c); see 66 Pa. C.S. §2808(c)(4) for similar language in Pennsylvania.
[47] See, e.g., the Illinois statute at 220 ILCS §5/16-108(f).

generation equipment.[48] California also exempts from transition charges certain 'changes in usage' by customers that result in reduced purchases of utility-supplied power. Among others, these include changes resulting from modifications to customer production equipment, operations, or processes; fuel switching, including fuel cells; and increased efficiency or replacement of certain cogeneration equipment.[49]

Illinois law offers another example of transition charge exemptions for self-generation and cogeneration facilities that meet specified criteria. It prohibits the state's utilities from imposing transition charges on electricity taken by a retail customer from cogeneration or self-generation facilities:

1. located on the customer's premises and serving only that customer;
2. sized for the customer's electrical load or, in the case of cogeneration facilities, sized for its thermal load and meeting PURPA operating and efficiency standards;
3. as to which the customer has an exclusive right to receive all the electric output, or for cogeneration facilities, an 'identified' amount, for at least a 5-year period; and
4. in the case of cogeneration facilities sized for the customer's thermal load, any excess electricity is sold at wholesale and subject to FERC jurisdiction.[50]

Illinois customers served by cogeneration or self-generation facilities that do *not* meet these criteria generally *are* subject to transition charges on all power taken from their own facilities as if the utility had supplied it, through at least December of 2006.[51] The law provides an exception for industrial customers taking power from their own self-service facilities installed before January 1997, or which are fueled by byproducts from their manufacturing process and sell more than 300 average megawatts into wholesale markets.[52]

Like Illinois, New Jersey exempts from transition charges 'electricity sold solely to the on-site customer of an on-site generating facility,' but the exemption will end if aggregate sales displace customer purchases exceeding 5 percent of the utility's 1997 gross revenues.[53]

Utility Regulatory Exemptions. In addition to transition charge exemptions, restructuring legislation may create or expand exemptions from 'public utility' status and resulting regulation for certain types of self-generation and cogeneration. As noted earlier,[54] many states' traditional utility laws provide limited regulatory exemptions for these resources, usually based on public policy favoring energy efficiency and renewable resources. Restructuring legislation, in order to advance public policy favoring competitive generation, sometimes expands these exemptions or establishes new ones.

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48 Cal. Pub. Utils. Code §372.

49 Id., §371.

50 220 ILCS §5/16-108(f), reflecting amendments made by Senate Bill 24, enacted July 1999.

51 Id. Pennsylvania law similarly provides that if customer-installed on-site generation, operating in parallel with the utility, significantly reduces purchases through the utility's system, a competitive transition charge will recover the customer's fully-allocated share of transition or stranded costs. 66 Pa. C.A.§2808(a).

52 Id.

53 *Electric Discount and Energy Competition Act* (A-10/S5, 208th New Jersey Legislature, February 1999, §28. The exemption does not apply to electricity sold from on on-site generation facility to off-site end-users.

54 See text accompanying footnote 9, and references cited there.

For example, California's 1996 restructuring law creates new exemptions from state regulatory jurisdiction for the ownership, operation, control, or management of generation facilities used for '*direct transactions*' (i.e., contracts between a generator and one or more retail customers to buy or sell power), or which *sell into the state's wholesale power exchange*.[55] The law also affirms pre-existing exemptions for cogeneration and nonconventional power facilities supplying power solely for their own or their tenants' use, or selling to not more than two other users on the same or adjacent property.[56]

Similarly, Michigan's recent legislation expressly provides that '[a] person using self-service power is not an electric supplier, electric utility, or a person conducting an electric utility business.'[57] It defines 'self-service power' to mean any of the following:

a) Electricity generated and consumed at an industrial site or contiguous industrial site or single commercial establishment or single residence without the use of an electric utility's transmission and distribution system.

b) Electricity generated primarily by the use of by-product fuels, including waste water solids, and the electricity is consumed as part of a contiguous facility, with the use of an electric utility's transmission and distribution system, but only if the point or points of receipt of the power within the facility are not greater than 3 miles distant from the point of generation.

c) A site or facility with load existing on [June 3, 2000] that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirement of this subdivision regardless of whether self-service power was being generated on [June 3, 2000].

d) A commercial or industrial facility or single residence that meets the requirements of subdivision (a) or (b) meets this definition whether or not the generation facility is owned by an entity different from the owner of the commercial or industrial site or single residence.[58]

Restructuring legislation may also contain provisions that are not, strictly speaking, exemptions from public utility status and regulation, but are functionally similar. The same Michigan law, for example, defines 'merchant plants' as nonutility-owned or -operated electric generating facilities over 100 kW capacity, and permits such plants to sell their capacity to anyone, provided only that they obtain a license if they sell at retail.[59] Regardless of form, what is important here is that restructuring initiatives often provide exemptions or alternative regulatory avenues for CHP/DG resources, not justified by or limited to traditional resource preferences, but in the broader interest of advancing competitive generation markets.

[55] Cal. Pub. Utils. Code §§216(i), 331(c).
[56] Id., §§216(i), 218(b)-(d).
[57] Michigan 90th Legislature, Public Act No. 141 (Enrolled Senate Bill 937), June 5, 2000; §10a(6). The same section makes clear that Michigan does not impose transition or similar charges on 'self-service power.'
[58] Id.
[59] Id., §§10g.(d) & 10e.(1).

Transitional Rate Reductions and Post-Transition Rates

Most state restructuring initiatives include provisions designed to freeze rates at pre-existing levels or to reduce them for at least some classes of utility customers during the transition to competition. These rate protections are significant here, not because they apply differently to customers with CHP/DG than to others but because, like transition or stranded cost charges, they can shape the competitive landscape for CHP/DG relative to other user options.

One of the first state electricity restructuring laws, New Hampshire's 1996 statute, observed that the state suffered from the nation's highest electric rates, and that the most compelling reason to restructure electric utilities was to reduce consumer costs by harnessing competitive forces. The legislation established the policy principle that its utilities 'in the near term, should work to reduce rates for all customers', but left it to the public utilities commission to implement this principle.[60]

Most restructuring legislation has been much more specific. For example, Pennsylvania's 1996 restructuring act caps electric utility rates for periods extending as late as 2005. *Total* charges to customers who continue to buy utility generation (bundled customers), and *nongeneration* charges to customers who buy generation from others, are capped at 1996 rates until mid-2001, or until the utility is no longer recovering transition costs and its customers can choose other suppliers. In addition, the *generation* component charged to bundled customers is subject to the 1996 rate cap through 2005, or until the same conditions are met.[61]

Other state restructuring laws go beyond capping rates to require actual rate reductions during the transition to full competition. Illinois legislation, for example, generally directs the Illinois commission not to increase or decrease rates from 1997 through 2004, but it creates significant exceptions. The most important is a directive to the state's larger utilities to reduce residential base rates by at least 15 percent below 1997 rates, and for the largest utilities, to reduce them an additional 5 percent beginning in 2001 or 2002 (depending on the utility).[62]

Other states require comparable rate reductions, at least for smaller customers and sometimes for all customer classes. Thus, for example, California law provides for reductions of 10-20 percent below 1996 rates for residential and small commercial customers from the start of retail access in 1998 through 2002.[63] New Jersey's 1999 legislation requires its electric utilities to reduce aggregate rates for each customer class to at least 5-10 percent below 1997 rates, and authorizes the state Board of Public Utilities to order further reductions.[64] For its largest utilities, Michigan mandates a 5 percent residential rate reduction and caps other rates at May 2000 levels from that date through 2003 (2005 for small commercial and manufacturing customers). After 2003, rates remain capped until 2014 or the date when the utility meets a 'market test' establishing that it controls less than 30 percent of the relevant generation market or has divested, sold, or transferred certain excess generation capacity.[65]

[60] New Hampshire HB 1392, §129:1-I.; §374-F:1-I.; & §374-F:3-XI.; May 1996.
[61] 66 Pa. C.S. §2804(4).
[62] 220 ILCS §5/16-111. Under this section, the commission can also approve utility applications for performance-based rates, real-time pricing tariffs, alternatives to traditional rate-of-return regulation, and elimination of fuel adjustment clauses, and utilities can seek rate increases if their rates fall below certain average indices.
[63] Cal. Pub. Utils. Code §330(a), (w).
[64] *Electric Discount and Energy Competition Act* (A-10/S5, 208th N.J. Legislature), February 1999; §4.c.-d.
[65] Michigan 90th Legislature, Public Act No. 141 (Enrolled Senate Bill 937), June 5, 2000; §10d(1)-(2) and 10f(1).

Rate caps, rate freezes, and rate reductions enacted by these and other restructuring statutes are transitional. As these examples illustrate, they are designed to end on specified dates or on the occurrence of specified conditions. While they remain in force, they have the effect of maintaining or reducing the amount that customers will need to pay their utilities for at least the generation portion of rates, regardless of the current cost of generation or the market value of power. This is clearly of benefit to eligible customers in the short term, but it can reduce the relative attractiveness of alternative sources such as CHP/DG that may actually be more competitive than utility generation in the longer run (i.e., once mandated rate protections expire).

Once rate protections and transition or stranded cost charges expire and truly competitive generation markets emerge, CHP/DG will need to compete with other generation sources on the merits. Its success will likely depend on the extent to which it can add value beyond the pure 'commodity' value of electricity–e.g., in the form of heating and cooling, reliability, redundancy, power quality, or similar characteristics–and on the post-transition rate designs that commissions adopt. Post-transition rate designs are a major and complex topic, well beyond the scope of this chapter. However, one of the most imortant issues for CHP/DG will be the extent to which distribution rates accurately reflect incremental costs to expand or upgrade utility distribution systems. Where they do not, CHP/DG benefits will continue to be limited primarily to site hosts, and projects valued accordingly. Where distribution rates do reflect utility expansion costs and provide clear price signals to customers who can help defer or avoid those costs, CHP/DG proponents will know where and when their projects add value to grid operations and may be able to leverage that value for the benefit of site hosts and others.

Summary and Conclusions

CHP/DG projects that consume all of their electric and thermal outputs on-site, do not distribute or sell to others, and do not require grid services for backup, maintenance power, or other ancillary services, will be affected by electricity restructuring mainly through its overall effect on energy markets and prices. However, the advent of competitive generation and access to utility distribution systems creates new opportunities for industrial and commercial CHP and self-generation using local resources. It also expands opportunities for community energy systems, district heating and cooling, and other forms of retail electricity and thermal sales.

That said, it is difficult to generalize about the impacts of state electricity restructuring on CHP/DG because state initiatives in this area are anything but simple or uniform. This chapter identifies key themes common to most restructuring schemes, but it also illustrates the wide variation among states in designing and implementing specific facets of competition and retail access. What is true under all of these approaches, however, is that:

- energy users will increasingly be free to choose CHP/DG alternatives, whether located on their own sites or elsewhere;
- CHP/DG suppliers will increasingly gain access to local utility distribution systems to transport and/or sell their electric output to others, allowing more flexible plant sizing and more efficient plant operations;
- local distribution utilities will increasingly supply unbundled, differentiated delivery services instead of, or in addition to, bundled services that include generation;
- during the transition to competition in states that restructure, competitive valuation of CHP/DG will need to take into account transition charges that customers cannot avoid, as well as rate caps and rate reductions that affect the value of alternative solutions; and

- in some states, CHP/DG projects may benefit from transition charge exemptions that can improve their economics relative to other solutions, and/or exemptions that allow them flexibility to compete without burdensome regulatory oversight.

In the end, users or developers considering CHP/DG will need to thoroughly understand their state's restructuring scheme, or its traditional regulatory scheme if the state has not restructured. However, in states that have, there are likely to be significantly increased opportunities for flexible and efficient CHP/DG installations over the long run, once the transition to competition is complete.

Federal Environmental Requirements

Throughout this section, readers will be introduced to important federal agencies and important national environmental acts that every cogenerator must be familiar with. In these days of global warming and concern over the environment, the environmental impacts of cogeneration is an important consideration. This section introduces the Environmental Protection Agency and significant national environmental acts and laws. The States have also enacted environmental statutes and promulgated rules and regulations that may impact CHP development. Though beyond the scope of this guide, developers should always contact the state environment office and/or office of energy facility siting to ensure compliance with all state environmental requirements.

Federal Environmental Guidelines

Environmental Protection Agency
The Environmental Protection Agency (EPA) is a federal agency invested with authority over pollution control. It is responsible for the development of detailed, specific standards prescribing the limits of pollution for various contaminants and sources. It is entrusted by Congress to reduce pollution to levels "requisite to protect the public health."

National Environmental Policy Act of 1969
On January 1, 1970, the National Environmental Policy Act of 1969 (P.L. 91-190) became law. The Act declares that all practical means will be applied to conduct federal activities in a way that will promote the general welfare and harmony of the environment. Section 102 of the Act directs that to the fullest extent possible the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this Act, and all agencies of the federal government shall include in every recommendation or report on proposals for legislation and other major federal activities significantly effecting the quality of the human environment, a detailed statement by the responsible official on:

- the environmental impact of the proposed action
- any adverse environmental effects which cannot be avoided should the proposed action be implemented
- alternatives to the proposed action
- the relationship between local sort-term use of man's environment and the maintenance and enhancement of long-term productivity
- any irreversible or irretrievable commitments of resources which would be involved if the proposed action should be implemented.

Primary environmental considerations in implementing cogeneration systems are regulations controlling air emissions (see chapter entitled Air Emissions Permitting Guidance) and water effluents of specific pollutants caused by fuel combustion. The most limiting regulations for fuel combustion systems are those dealing with air pollution caused by siting and operational requirements. To a lesser extent water quality and solid waste regulations also impact combustion systems.

Preparing Environmental Impact Statements
When a proposed action is projected to have a significant impact on the quality of the human environment, an environmental impact statement (EIS) must be prepared. An EIS is intended to

provide decision-makers and the public with a complete and objective evaluation of significant environmental impacts, both beneficial and adverse, resulting from a proposed action and all reasonable alternatives. An EIS is a major vehicle for fulfilling the substantive environmental goals set forth in the National Environmental Policy Act.

Preparing a New EIS

The process includes the following:

- scoping the EIS to focus the analysis on significant issues and reasonable alternatives
- publishing a notice of intent in the Federal Register to notify persons or agencies interested in, or affected by, a proposed action and to seek information and/or participation in scoping
- conducting the analysis and preparing the draft EIS
- issuing the draft EIS for public and other agency comments
- analyzing the comments and preparing the final EIS
- issuing the final EIS for comment
- reaching and recording the decision.

Once the draft EIS is completed and has gone through internal review, it is printed, filed with the EPA, and issued for public review and comment. A period of at least 60 days from the date the draft EIS is transmitted to EPA must be allowed for public review. A notice as to the availability of the draft EIS is normally published in the Federal Register and a press release is usually prepared for national and/or local media to announce the availability of the draft and to announce any public meeting or hearings.

Copies of the draft EIS are distributed to federal, state, and local agencies, individuals, and organizations on the mailing list and they are invited to be participants in public meetings.

Public meetings/hearings are usually held during the draft review period to receive comments on the draft. Once all meetings/hearings are held and public and agency comments received, the input is recorded and a final EIS is prepared. All relevant comments that are substantive and that relate to inadequacies or inaccuracies in the analysis or methodologies used, identify new impacts or recommend reasonable new alternatives or mitigation measures, or involve substantive disagreements on interpretation of significance are taken into account.

If substantive comments are received, the official in charge must determine whether the new impacts, new alternatives, or new mitigation measures should be analyzed in either the final EIS, a supplement to the draft EIS, or a completely revised and recirculated draft EIS.

Once it is determined that a final EIS should be prepared, all substantive comments, changes, corrections, and revisions are incorporated into a preliminary final EIS. The document is then circulated for internal concurrence and must be approved by the manager responsible for authorizing the action covered by the EIS.

Following approval, the EIS is printed, filed with the EPA, and distributed to the public. A notice of availability must be published in the Federal Register and a press release is issued to national and/or local media. Copies are generally made available to all substantive comments and others who have a strong interest in the proposal(s).

The Record of Decision (ROD) is not issued until a 30-day no-action period has lapsed following the publication of the EPA notice on the final EIS in the Federal Register and other program-specific requirements, if any, have been met.

Comments on the final EIS, if any, must be reviewed to determine if they identify significant issues not previously addressed or introduce new significant information. If substantial comments are received, the manager responsible for preparing the EIS must determine whether a supplemental draft EIS or supplemental final EIS is warranted. If not, the commentator(s) are advised, if possible and appropriate, of the availability date for the ROD.

The public must be advised of the availability of the ROD and a notice of availability is published in the Federal Register as well as in national and/or local press. Copies of the decision are made available to substantive commentators and to others known to have a strong interest in the proposal(s).

Following the 30-day availability period, a decision may be made. Decisions on an EIS are recorded in a public ROD. No action concerning a proposal may be taken until the ROD has been issued, except under conditions specified in 40 C.F.R. 1506.1.

Incorporating by Reference (40 C.F.R. 1502.4)
Incorporating previous analysis by reference in an EIS is a technique used to avoid redundancies in analysis and to reduce the bulk of NEPA documents. Materials or analyses incorporated by reference are not limited to NEPA documents. Special technical or professional studies and analysis prepared by other federal agencies, state, local, tribal governments, or private interests may be incorporated by reference. If a document is incorporated by reference is at the heart of the EIS, it should be circulated for comment as part of the draft.

Supplementing (40 C.F.R. 1502.9(c))
Supplements to an existing draft or final EIS are prepared when additional environmental analysis is needed. The relationship between the supplement and the existing EIS is lateral, i.e., the proposed action and alternatives are analyzed to the same level of specificity and detail. A supplemental EIS is often used to address alternative not previously analyzed and may lead to new decisions.

A supplement is generally prepared when:

- there are substantial changes in the proposed action that are relevant to environmental concerns
- there are significant new circumstances or facts relevant to environmental concerns and bearing on the proposed action or its impacts which were not addressed in the existing analyses
- using another agency's environmental document and additional analysis is needed.

An example of when supplementing an EIS may be appropriate is when a substantial change is proposed for a planned transmission line, pipe line, or power plant which was analyzed in a previous EIS.

Using Another Agency's EIS (40 C.F.R. 1506.3)
The purpose of using another agency's environmental document for NEPA compliance is to reduce paperwork, eliminate duplication, and/or make the process more efficient. Use of another agency's EIS is accomplished by either formally cooperating in its development or adopting all or parts of the EIS.

Tiering (40 C.F.R. 1508.28)
Tiering is used to prepare new, more specific, or more narrow environmental documents without duplicating relevant parts of previously prepared, more general, or broader documents. The more specific or more narrow environmental documents incorporate by reference the general discussion and analysis from the broader document and concentrate on the issues and impacts of the project which are not specifically covered in the broader document.

Tiering is appropriate when:

- The analysis for the proposed action will be a more site- or project-specific refinement or extension of the existing analysis.
- The decisions associated with the existing environmental document will not be changed as a result of the tiering.

Existing environmental analysis should be used in analyzing impacts associated with a proposed action to the extent possible and appropriate. This approach builds on work that has already been done, avoids redundancy, and provides a coherent and logical record of the analytical and decision making process (NEPA Handbook, 14-1790-1).

Several questions must be addressed before an existing environmental analysis may be used:

- Have any relevant environmental analysis related to the proposed action been prepared?
- Who prepared and cooperated in the preparation of the analysis?
- Do any of the existing analysis fully analyze the proposed action and alternatives?

In determining whether an existing environmental impact statement covers a proposed action currently under consideration, the criteria are as follows:

- The new proposed action is a feature of or essentially the same as the alternative selected in the document being reviewed.
- A reasonable range of alternatives to the new proposed action was analyzed in the document being reviewed, i.e., there are no unresolved conflicts involving alternative resource uses for the new proposed action.
- The circumstances or information upon which the document being reviewed is based are still valid and germane to the new proposed action, i.e., there is no significant change in circumstances and no significant new information.
- The methodology or analytical approach used in the document being reviewed is appropriate for the new proposed action.

- The direct and indirect impacts of the new proposed action are not significantly different than, or are essentially the same as those identified in the document being reviewed.

Water Quality

Federal Water Pollution Control Act (WPCA)
Under the Federal Water Pollution Control Act an industry or "point source discharging pollutants into navigable water must have a National Pollution Discharge Elimination permit. A "point source" is a discernible, confined, discrete source.

The Act authorizes states to adopt water quality standards. State standards consider the value of water for public drinking supplies, propagation of fish and wildlife, and recreation, among other uses. Each standard considers the respective uses and value of the water and includes criteria based on those uses.

A "point source" wishing to discharge anything into navigable waters must comply with federal and state water quality standards. Applicants must obtain a certificate that all discharges will comply with the standards.

A certificate is required for any discharge. It applies even when a water user does not add anything to discharged water. For instance, a dam or diversion adds nothing to the water, but it may diminish flow needed to dilute downstream wastes. It may also change naturally-occurring temperatures and the dissolved oxygen level. If a state rule on one of these water quality parameters is violated, a certificate of compliance will be denied.

The Act requires that discharges comply "with any other appropriate requirement of state law." It requires federal permits and licenses be granted subject to any appropriate requirement of state law.

New Source Performance Standards
New Source Performance Standards for water quality have been established for several industrial source categories, including steam electric power generating. These standards apply to facilities generating electricity for distribution and sale, with the exception of facilities with less than 25 MW rated net generation capacity or any units that are part of an electric utilities system with a total net generating capacity less than 150 MW. No water quality standards exist or are proposed for other combustion systems that can be used in cogeneration.

National Pollutant Discharge Elimination System Permit (402 Permit)
A National Pollutant Discharge Elimination Systems (NPDES) permit is required where a waste water source is discharged to "waters of the United States." If a cogeneration project affects the quality of water in any way by adding sediments, decreasing oxygen content, or increasing temperature, this may be construed as discharging a pollutant and requires a NPDES permit. For more information, contact the regional EPA office.

A NPDES permit is usually required in all states for industrial wastewater. The permit application must indicate the type of facility to be operated, quantities of wastewater, pollution control system used, and composition of the waste waters. States are responsible for regulating solid wastes for industrial sources that may impact surface and ground waters. A coal-fired boiler will generate fly ash and bottom ash that must be disposed of in approved landfills. Boiler wastes are usually exempt from hazardous waste regulations. However, the state may require an analysis of the wastes to assess whether surface or ground waters may be contaminated, especially by heavy metals in the bottom ash.

Table 2
NPDES Permit Application Forms

Permit Category	Application Form
Any industrial, commercial, manufacturing, or mining activity	Standard Form C [EPA Form 7550-23A (7-73)]
a. In quantities exceeding 50,000 gallons on any day of the year	
b. In quantities of 50,000 gallons or less but which discharges a toxic pollutant	

The application requires information on waste source flow and expected characteristics, disposal method, water supply, waste water disposal, water supply volumes, water utilization, planned improvements, storm water treatment, plant operation, materials and chemicals used, and production.

Solid and Hazardous Waste

Resource Conservation and Recovery Act (RCRA)
Solid and hazardous waste management is regulated under the Resource Conservation and Recovery Act (RCRA) which addresses pollution of the terrestrial environment by solid and hazardous wastes, including those generated by air- and water-pollution control devices. These regulations are not expected to have much impact on combustion systems used in cogeneration applications as most of the wastes produced by these systems are exempt from the regulations. These wastes include fly ash, bottom ash, slag, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels. Management of these wastes will be controlled by state regulations. Solid or liquid waste that may meet the criteria of hazardous wastes are those containing corrosion inhibitors used to prevent boiler tube fouling in steam turbine systems.

Other Federal Environmental Regulations

Endangered Species Act of 1973
In 1973, the United States Congress passed the Endangered Species Act, P.L. 93-205. This act protects fish, wildlife and plants endangered or threatened with extinction. The Act also protects the ecosystems on which they depend. Federal agencies are to work with state and local agencies to protect endangered species.

Various species of fish, wildlife, and plants in the United States have been rendered extinct or in danger of extinction as a consequence of economic growth and development. These species of fish, wildlife, and plants have been found to have esthetic, ecological, educational, historical, recreational, and scientific value. Therefore, the United States encourages the states and other interested parties to develop and maintain conservation programs that meet national and international standards to preserve the nation's heritage in fish, wildlife, and plants. The ecosystem upon which endangered and threatened species depend must also be preserved.

It is declared to be the policy of Congress that all federal departments and agencies shall seek to conserve endangered and threatened species and shall utilize their authorities in furtherance of the purposes of the Act. Federal agencies shall cooperate with state and local agencies to resolve water resource issues in concert with conservation of endangered species.

Each federal agency shall, in consultation with and assistance of the Secretary, ensure that any action authorized, funded, or carried out by such agency (action) is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of the habitat of such species...unless the agency has been granted an exemption for such action. In fulfilling the requirements of this paragraph each agency must use the best scientific and commercial data available.

A federal agency shall consult with the Secretary on any proposed agency action if there is reason to believe that an endangered or threatened species may be present in the area affected by a project and the implementation of such action will likely affect such species.

A biological assessment to identify any endangered species or threatened species for the purpose of identifying any endangered or threatened species which is likely to be affected by such action. Such assessment must be completed within 180 days if a permit or license application is involved (unless the agency provides the applicant with a written statement setting forth the estimated length of the proposed extension and the reason therefore). The assessment must be completed before any permit or license is granted and before any contract for construction is entered into or before any construction is begun. Such assessment may be undertaken as part of a federal agency's compliance with the requirements of section 102 of the National Environmental Policy Act of 1969 (42 U.S.C. 4332).

Any person who may wish to apply for an exemption under provisions of the Act for that action may conduct a biological assessment to identify any endangered species or threatened species which is likely to be affected by such action. Any such biological assessment must, however, be conducted in cooperation with the Secretary and under the supervision of the appropriate federal agency. Power plant sites, as well as pipe line and transmission line considerations, may well be impacted by provisions of the Endangered Species Act.

Air Emissions Permitting Guidance

Introduction

This guidance document provides a limited overview of the permitting process and key issues for Combined Heat and Power (CHP) facilities. The federal and state statutes and regulations provide the basis for the regulatory process. Each project is evaluated on a case-by-case basis. The air quality of the local area and the size and characteristics of the project affect the complexity of the permitting process. The reader should always consult state or local air agencies for specific requirements applicable to the particular location and project.

Definitions of key terms are summarized in a glossary at the end of this chapter.

Overview of the Clean Air Act

The Clean Air Act (CAA) was enacted in 1970 by Congress to protect ambient air quality, and has been amended several times. The most recent significant amendments occurred in 1990.[66] The CAA requires permitting of pollution sources and is implemented by the U.S. Environmental Protection Agency (EPA) and the States. The CAA is designed to address a number of problems:

- *Ambient Air Quality.* The CAA was established to protect the health and welfare of the public. The National Ambient Air Quality Standards serve as the benchmark for determining *clean air* and *dirty air*.
- *New Source Review.* Congress recognized that air pollution is directly related to human activities and that managing existing and new sources of air pollution was necessary. The air permitting process was formalized.
- *Acid rain.* Emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) react in the atmosphere to form compounds that are transported long distances and cause acidification in lakes, streams and soils; nutrient saturation of coastal waters and river basins; and damage to crops and forests.
- *Photochemical smog.* NO_X emissions react with volatile organic compounds (VOCs), such as gasoline vapors, in sunlight to produce ground-level ozone, or "smog." This can cause lung damage and exacerbate asthma and emphysema.
- *Regional haze.* Very small particles (less than a few microns in diameter) in fossil fuel emissions degrade visibility and are thought to cause lung problems. EPA has been given authority to regulate haze in national parks.
- *Mercury contamination.* Mercury is a neurotoxin that accumulates in human tissue and causes serious neurological problems. Humans are exposed primarily through repeated consumption of fish that accumulate mercury compounds.

[66] The following summary of the Clean Air Act draws significantly from "A Guide to the Clean Air Act for the Renewable Energy Community," by David Wooley for the Renewable Energy Policy Project, February 2000.

Structure of the Clean Air Act
The major elements of the 1990 amendments of the CAA are summarized as follows:

- Title I is an extremely important Title for CHP facilities because it establishes the system, described below, of criteria pollutants, national ambient air quality standards and attainment and non-attainment areas.

- Title II addresses vehicle tailpipe emissions and fuel standards on vehicles, and is not relevant to CHP.

- Title III addresses protection of human health from air toxics. It does not affect CHP projects.

- Title IV regulates emissions of sulfur dioxide and nitrogen oxides in order to control acid rain through a market-based emission allowance system (described below). It is applicable to relevant to CHP facilities over a certain size, as described below.

- Title V requires a comprehensive operating permit for all major sources of air pollution including most CHP facilities.

- Title VI regulates emissions of compounds such as chlorofluorocarbons implicated in the destruction of the stratospheric ozone layer. These provisions don't affect CHP facilities.

Air Quality Standards and State Implementation Plans

The National Ambient Air Quality Standards (NAAQS) are set by the EPA, under the authority of the CAA. The NAAQS limit the allowable outdoor concentration of six *criteria pollutants*:

- Carbon monoxide (CO)
- Nitrogen oxides (NO_x)
- Sulfur dioxide (SO_2)
- Particulate matter (PM/PM-10) [67]
- Ozone
- Lead

State air agencies develop State Implementation Plans (SIPs) to implement the NAAQS. States generally have significant discretion in choosing emission control strategies (such as stack-gas cleaning devices for power plants, or vehicle inspection and maintenance programs) to achieve NAAQS. The plans are submitted to EPA for approval. Once the SIP is approved, the SIP control strategies are implemented through permits for all *major sources* of air pollution. (See definition of *major source* below.) If the EPA rejects the SIP and the State does not submit a satisfactory revised SIP, then EPA develops a Federal Implementation Plan for the State, including emission control strategies and permits.

[67] EPA has designated PM-10 (particulate matter with an aerodynamic diameter less than 10 microns) as a criteria pollutant by promulgating National Ambient Air Quality Standards (NAAQS) for this pollutant as a replacement for total particulate matter (PM). Thus, the determination of potential to emit for PM-10 emissions as well as total PM emissions is required in applicability determinations.

New Source Review
If a new source of air pollution, or a modification of an existing source is proposed in a way that increases emissions, a new source permit is required or an existing permit must be modified. New Source Review (NSR) is a pre-construction review and permitting program. This program is intended to ensure that new emissions will not degrade air quality in *attainment areas* (areas that meet NAAQS) or interfere with plans to achieve attainment in *non-attainment areas* (areas that do not meet NAAQS).

NSR comprises two programs:

- Prevention of Significant Deterioration (PSD), which applies in attainment or unclassifiable areas; and
- Non-Attainment Area (NAA), which applies in non-attainment areas and imposes stricter requirements.

For a given project, PSD may be applicable for one pollutant and NAA may be applicable for another pollutant.

Sources are defined as *major* or *minor*, as defined and discussed below. Both major and minor sources must obtain a permit. The following discussion focuses on major source permitting.

New *major sources* and *modified major sources* in attainment areas must use *Best Available Control Technology (BACT)* and in non-attainment areas must use *Lowest Achievable Emission Rate (LAER)*. In addition, in non-attainment areas new sources must offset their emissions by purchasing emission reduction credits from existing sources that agree to reduce emissions by an amount greater than the emissions from the new source. BACT and LAER, and other aspects of PSD and NAA, are described in more detail below.

Direct Federal Controls
In addition to the NAAQS/SIP process, the federal government exerts direct control, independent of the States, in several areas, as summarized below.

Acid rain. In the 1990 CAA Amendments, Congress imposed plant-by-plant SO_2 emission limits on hundreds of power plants, and allowed use of a “cap and trade” system (discussed below) to comply with the limits.

Interstate air pollution. EPA can impose more stringent controls to prevent emissions from one state interfering with the ability of another state to meet NAAQS.

Air toxics. EPA is directed to set national emission performance standards for 189 toxic substances (sometimes called Hazardous Air Pollutants, or HAPs), applicable to specific categories of industrial sources (such as chemical plants). At this point, "electric utility steam generating units"[68] are exempted from these "Maximum Achievable Control Technology" (MACT) limits. However, it is expected that EPA in early 2001 EPA will propose MACT standards for:

- industrial/commercial/institutional boilers;
- stationary combustion turbines; and
- reciprocating internal combustion engines.

These standards will set flue gas concentration limits for key air toxics emissions from these categories, and will likely become effective in 2002. EPA has also determined that it will develop MACT standards for "electric utility steam generating units," which may be proposed in 2003.

New Source Performance Standards
New Source Performance Standards (NSPS) is an emission standard prescribed for criteria pollutants from certain stationary source categories under Section 111 of the Clean Air Act. All new emission units are required to meet applicable NSPS. If the facility is subject to Prevention of Significant Deterioration (PSD) regulations then emission units must meet Best Available Control Technology (BACT) requirements. BACT requirements can be more stringent than NSPS requirements.

Operating Permits
Once a pre-construction permit has been approved under NSR, operating permits must be obtained under Titles IV and V.

Prevention of Significant Deterioration (PSD)[69]

PSD permits are required prior to facility construction for *major sources* in attainment areas. The key criteria for determining applicability are:

- The project is located in an *attainment area*; and
- The project is a major source or is classified as a major modification because the net emissions increase exceeds established thresholds.

Location in Attainment Area
The PSD program is applicable if the source would be located in an area formally designated by a State as *attainment* or unclassifiable for a given criteria pollutant.[i] An *attainment area* is an area that meets NAAQS for a given pollutant.[ii] A source's location can be attainment or

[68] The CAA defines "electric utility steam generating unit" as "any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that co-generates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electric output to any utility power distribution system for sale shall be considered an electric utility steam generating unit." In an interpretive ruling issued in May 2000 (Federal Register, 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories; Final Rule," May 25, 2000) EPA clarified that the upcoming combustion turbine MACT will affect all combustion turbines, whether they are simple cycle or combined cycle.
[69] This section as well as succeeding sections draw substantially from "New Source Review Manual," a draft guidance document prepared by EPA dated October 1990.

unclassified for some pollutants and simultaneously non-attainment for others. If the project would emit only pollutants for which the area has been designated non-attainment, NAA rather than PSD would apply, as discussed below.

Major Source or Major Modification

Before defining *major source*, it is important to understand what is meant by the basic term *source*. A CHP facility would be a *stationary source*, which is defined as any building, structure, facility, or installation that emits or may emit any air pollutant subject to regulation under the CAA.[iii] *Building, structure, facility*, or *installation* generally means all the pollutant-emitting activities that:

1. belong to the same Standard Industrial Classification (SIC) major group (2-digit SIC code);[iv]
2. are located on one or more contiguous or adjacent properties; and
3. are under common ownership or control.

A frequent question, particularly at large industrial complexes, is how to deal with multiple emissions units at a single location that do not fall under the same two-digit SIC code. In this situation the source is classified according to the primary activity at the site, which is determined by its principal product (or group of products) produced or distributed, or by the services it renders. Facilities that convey, store, or otherwise assist in the production of the principal product are called *support facilities*. An emissions unit serving as a support facility for two or more primary activities (sources) is to be considered part of the primary activity that relies most heavily on its support.

It is important to note that if a new support facility would by itself be a major source based on its source category classification and potential to emit, it would be subject to PSD review even though the primary source, of which it is a part, is not major and therefore exempt from review.

Evaluations regarding the second criterion ("contiguous or adjacent") are made on a case-by-case basis. Facilities that are miles away may still be considered "adjacent" if they are judged to be functionally inter-related.

The third criterion is also addressed on a case-by-case basis. While ownership is generally clear, whether or not there is "common control" is sometimes a contentious issue. This is discussed below under "Netting Issues for CHP."

A key criterion in determining PSD applicability is whether the source is sufficiently large to be a *major* stationary source or *major modification*. A *major source* is one that has the potential to emit more than 250 TPY of any pollutant regulated under the CAA. However, there are 28 industrial categories that are subject to a 100 tons per year (TPY) threshold.[v] In addition to many specific categories of industrial process facilities, the 28 categories include several of potential relevance to CHP projects:

- fossil fuel-fired steam electric plants of more than 250 million British thermal units (Btu) per hour heat input; and
- fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu per hour heat input.

A situation sometimes occurs in which an emissions unit that is included in the 28 listed source categories (and so is subject to a 100 TPY threshold), is located within a parent source whose primary activity is not on the list (and is therefore subject to a 250 TPY threshold). An *emissions unit* is any part of a stationary source that emits or has the potential to emit any pollutant subject to regulation under the CAA. A source which, when considered alone, would be major (and hence subject to PSD) cannot "hide" within a different and less restrictive source category in order to escape applicability.

A *major modification* is a physical change or change in the method of operation at an existing major source that causes a net emissions increase of any regulated pollutant at a level that is considered *significant* (as discussed below). When a *minor* source, i.e., one that does not meet the definition of *major*, makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a major source that is subject to PSD review.

Source size is defined in terms of *potential to emit*, which is the facility's capability at maximum design capacity to emit a pollutant, except as constrained by federally-enforceable conditions.[vi] These conditions could include:

- Requirements to install and operate air pollution control equipment at prescribed efficiencies;
- Restrictions on design capacity utilization; and/or
- Restrictions on hours of operation.

A permit condition that temporarily restricts production to a level at which the source does not intend to operate for any extensive time is not valid if it appears to be intended to circumvent the pre-construction review requirements for major source by making the source temporarily minor. Such permit limits cannot be used in the determination of potential to emit.

In the absence of federally enforceable restrictions, the potential to emit calculations should be based on uncontrolled emissions at maximum design or achievable capacity (whichever is higher) and year-round continuous operation (8,760 hours per year).

By limiting the potential to emit with enforceable restrictions, a source may be able to avoid qualifying as a major source. Such "synthetic minors" may not be required to obtain an operating permit under Title V; however, such sources will still need a state-issued minor source permit which sets out the federally-enforceable limits.

If a source cannot escape the major source or major modification designation, calculation of the potential emissions at the highest possible level will provide future flexibility. For example, a high level of potential emissions could allow later operational changes that result in increased emissions without triggering major modification designation.

When determining the potential to emit for a source, emissions should be estimated for individual emissions units using an engineering approach. These individual values should then be summed to arrive at the potential emissions for the source. For each emissions unit, the estimate should be based on the most representative data available. Methods of estimating potential to emit may include:

- federally enforceable operational limits, including the effect of pollution control equipment;
- performance test data on similar units;
- equipment vendor emissions data and guarantees;
- test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111(d) standards for designated pollutants;
- AP-42 emission factors;[vii]
- emission factors from technical literature; and
- State emission inventory questionnaires for comparable sources.

If a new source is not considered major, a PSD permit is not required. However, if there is an increase in emissions, a minor source state construction permit may be required.

For a modification to an existing source to be designated as a major modification, there must be a *significant* emissions increase. If a project would cause increases in net emissions for any pollutant as summarized in Table 3, those increases would be considered significant and would be subject to PSD.

If a proposed project is near a national park or other areas of special natural, scenic, recreational, or historic value, there are additional criteria affecting determination of significance that may apply. In this case, it is extremely important to consult early with the state air agency and with the U.S. Forest Service.

The significance thresholds and the calculation of net emissions increase are of crucial importance for project proposers. If the net emissions increase is not significant, BACT should not be required.

Emissions Netting

Emissions netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine if a *net emissions increase* of a pollutant will result from a proposed physical change or change in method of operation. If a net emissions increase is shown to result, PSD applies to each pollutant's emissions for which the net increase is significant, as shown in Table 3.

Table 3
Significant Emission Rates for Pollutants Regulated Under the Clean Air Act[viii]

Pollutant Emissions (tons/year)	
Criteria Pollutants	
Carbon monoxide	100
Nitrogen oxides[a]	40
Sulfur dioxide[b]	40
Particulate matter (PM/PM-10)	25/15
Ozone (VOC)	40 (of VOC's)
Lead	0.6
Non-Criteria Pollutants	
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl chloride	1
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide (H_2S)	10
Total reduced sulfur compounds (including H_2S)	10

[a] Nitrogen dioxide is the compound regulated as a criteria pollutant; however, significant emissions are based on the sum of all oxides of nitrogen.
[b] Sulfur dioxide is the measured surrogate for the criteria pollutant sulfur oxides. Sulfur oxides have been made subject to regulation explicitly through the proposal of 40 CFR 60 Subpart J as of August 17, 1989.

The PSD definition of a *net emissions increase*[ix] can be summarized with the following equation:

Net Emissions Change

EQUALS
Emissions <u>increases</u> associated with the proposed source or modification
MINUS
Source-wide emissions <u>decreases</u> that are *creditable* and *contemporaneous*
PLUS
Source-wide emissions <u>increases</u> that are *creditable* and *contemporaneous*

The first component narrowly includes only the emissions increases associated with a particular change at the source. The second and third components more broadly includes all contemporaneous, creditable emission increases and decreases that are *source-wide*, i.e., occurring anywhere at the entire source. EPA has required that netting must take place at the same source; emissions reductions cannot be traded between sources. This point is discussed further below, under “Netting Issues for CHP.”

Generally, consideration of contemporaneous emissions changes is allowed only in cases involving existing <u>major</u> sources. In other words, minor sources are usually not eligible to net emissions changes. This point is discussed further below, under “Netting Issues for CHP.”

If the proposed emissions increase at a major source is by itself (without considering any decreases) less than significant, the permitting agency may not consider previous contemporaneous small (i.e., less than significant) emissions increases at the source. In other words, the netting equation (the summation of contemporaneous emissions increases and decreases) may not be triggered unless there will be a significant emissions increase from the proposed modification. Usually, at least two basic questions should be asked when evaluating the construction of multiple minor projects to determine if they should have been considered a single project. First, were the projects proposed over a relatively short period of time? Second, could the changes be considered as part of a single project?

It is important to note that when any emissions decrease is claimed (including those associated with the proposed modification), all source-wide *creditable* (i.e., enforceable, as discussed further below) and *contemporaneous* emissions increases and decreases of the pollutant subject to netting must be included in the PSD applicability determination. A deliberate decision to split an otherwise *significant* project into two or more smaller projects to avoid PSD review would be viewed as circumvention and would subject the entire project to enforcement.

Generally, to be *contemporaneous*, the changes in emissions must occur within a period beginning 5 years before the date construction is expected to commence and ending when the emissions increase from the modification occurs. The netting analysis requires two consecutive years of actual emissions data. Generally, this is the most recent two years. However, if these years are not representative (for example, due to a major outage), then another consecutive two year period can be chosen from within the 5 year contemporaneous period.

An increase resulting from a physical change at a source occurs when the new emissions unit becomes operational and begins to emit a pollutant. A replacement that requires a shakedown period becomes operational only after a reasonable shakedown period, not to exceed 180 days. Since the date construction actually will commence is unknown at the time the applicability determination takes place and is simply a scheduled date projected by the source, the contemporaneous period may shift if construction does not commence as scheduled.

Many states have developed PSD regulations that allow different time frames for definitions of contemporaneous. Where approved by EPA, the time periods specified in these regulations govern the contemporaneous timeframe.

There are further restrictions on the contemporaneous emissions changes that can be credited in determining net increases. To be *creditable*, a contemporaneous reduction must in effect be federally enforceable on and after the date construction on the proposed modification begins.

The actual reduction must take place before or at the time of the emissions increase from any of the new or modified emissions units occurs. In addition, the reviewing agency must ensure that the source has maintained any contemporaneous decrease that the source claims has occurred in the past. The source must either demonstrate that the decrease was federally enforceable at the time the source claims it occurred, or it must otherwise demonstrate that the decrease was maintained until the present time and will continue until it becomes federally enforceable. An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit that was never constructed or operated, including units that received a PSD permit.

The following basic criteria should be used when quantifying the increase or decrease:

- For proposed new or modified units that have not begun normal operations, the potential to emit must be used to determine the increase from the units.
- For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the period just prior to the change that resulted in the emissions increase. These emissions are calculated using the actual hours of operation, capacity, fuel combusted and other parameters that affected the unit's emissions over the averaging period. In certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level, the reviewing agency may presume that source-specific allowable emissions (or a fraction thereof) are equivalent to (and therefore are used in place of) actual emissions at the unit.
- A source cannot receive emission reduction credit for reducing any portion of actual emissions that resulted because the source was operating out of compliance.

An emissions increase or decrease is creditable only if the relevant reviewing authority has not relied on it in issuing a PSD permit for the source, and the permit is still in effect when the change in actual emissions from the proposed modification occurs. A reviewing authority relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment or ambient standard. In other words, an emissions increase or decrease already considered in a source's PSD permit can't be considered a contemporaneous increase or decrease since the increases or decrease was relied upon for the purpose of issuing the permit. This is done to avoid "double counting" of emissions changes.

For the purpose of minimizing confusion and improper applicability determinations, the following six-step procedure is recommended in applying the emissions netting equation:

Step 1. Determine the emissions increases from the proposed project.

Step 2. Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

Step 3. Determine which emissions units at the source have experienced an increase or decrease in emissions during the contemporaneous period.

Step 4. Determine which emissions changes are creditable.

Step 5. Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

Step 6. Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

Netting Issues for CHP
Often, start-up of a CHP unit will make it possible for other facilities to reduce emissions. For example, a CHP project at an industrial facility or district energy plant[70] will allow the retirement or reduced operation of existing boilers. Alternatively, a CHP facility might be installed at a district energy plant in order to supply heat to new customers, who can then cease operation of their boilers.

Generally, the CHP project proposer will desire to get credit for these emission reductions through a process called *netting*, which is defined and discussed above under "Emissions Netting." Netting is desirable because it may make it possible to avoid PSD requirements. There are, however, a number of aspects of the netting process that are potentially problematic for some CHP projects.

Single Source
EPA requires that netting must take place at the same source, i.e., emission reductions cannot be traded between sources. Generally, air quality regulators prefer to see facilities aggregated into one source and therefore one permit. Within a group of units that is considered one source, netting is not a problem. However, while the permitting authority may encourage combining the permits, this presents significant problems in "third party projects," where the CHP facility is built by a third party which then sells the thermal output and perhaps some or all of the electric output. The third party CHP developer will generally want to avoid this because of liability and control issues. There may be emissions elsewhere in the host plant that the CHP developer does not wish to be liable for, and if permitting is combined the CHP project owner will have less control over its asset.

"Control" will be a key consideration in determining whether permitting for a CHP facility should be combined into the permit for the purchaser of output from the CHP facility. Generally, the greater the proportion of the total CHP output used by the "host" facility, the stronger the case that the CHP facility, even if owned by a third party, is under the control of the user. An unofficial guidance suggests that if over 50 percent of the output of the facility is purchased by a user, then the proposed facility is under the control of that user. However, it is not clear how this would be applied in a CHP facility, which produces at least two forms of output (electricity and thermal energy, and sometimes mechanical energy). For example, would a unit of thermal output be counted the same as a unit of electric output?

CHP facilities provide significant environmental benefits by producing multiple useful energy outputs from the same fossil fuel. CHP facilities are also increasingly implemented through third party contracts. The CHP industry is currently seeking clarification from EPA on how CHP projects can be considered in the permitting process so that these environmental benefits are recognized. One area requiring clarification is how "control" is assessed, and how to recognize emission reductions while recognizing the problems posed for third party CHP developers by combining permits with users.

Major and Minor Sources
Generally, consideration of contemporaneous emissions changes is allowed only in cases involving existing major sources. In other words, minor sources are usually not eligible to net

[70] A district energy plant is a facility that produces steam, hot water and/or chilled water for distribution through a network of pipes to multiple buildings to meet thermal energy needs, including space heating, air conditioning, domestic hot water and industrial processes.

emissions changes. Industry representatives are currently discussing with EPA the conditions under which district heating systems could consider in the netting equation emission reductions in minor sources connecting to a district heating system. For example, it may be possible to implement contracts allowing the building boiler to be considered part of the district energy plant source and addressing limits on any future operation of the boiler, as discussed in the next paragraph.

Removal of Netted Sources

The requirement that a contemporaneous reduction must in effect be federally enforceable on the date construction on the proposed modification begins is of particular relevance to district energy CHP. This is because if the district energy system is to get credit for emissions eliminated in building boilers it must show that these reductions are enforceable. Ideally, this would be accomplished through permanent shutdown and possibly removal of the boilers. However, this may not always be practicable, or the building may wish to retain the boiler for back-up. Industry representatives are currently exploring whether some type of contractual commitment could meet the criterion of federal enforceability of the reduction in emissions from a building boiler that would no longer be operated because it is receiving district heating service. For example, in combination a contractual commitment bringing the building boiler into the district heating plant permit, a limit on the potential to emit in the building boiler and provisions for ongoing monitoring of boiler operations could be included.

Best Available Control Technology (BACT)

For sources subject to PSD permitting, Best Available Control Technology (BACT) must be applied. BACT is an emission limitation that the regulatory authority, on a case-by-case basis, determines is achievable taking into account energy, environmental and economic impacts and other costs. For criteria pollutants, BACT must be at least as stringent as NSPS.

The key steps in the BACT analysis are:

- Identify all control technologies
- Eliminate technically infeasible ones
- Rank technologies by control effectiveness
- Evaluate technologies considering energy, environmental, and economic impacts
- Select most effective option

In this analysis all available control technologies are ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent–or "top"–alternative. That alternative is established as BACT unless the applicant demonstrates that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Individual BACT determinations are performed for each pollutant subject to a PSD review emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review.

Applicants are expected to identify all demonstrated and potentially applicable control technology alternatives. Information sources to consider include:

- EPA's BACT/LAER Clearinghouse and Control Technology Center;
- New Source Review (NSR) bulletin board
- control technology vendors;
- federal/state/local new source review permits and associated inspection/performance test reports;
- environmental consultants; and
- technical journals, reports and newsletters air pollution control seminars.

Air Quality Analysis

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from a proposed project, in conjunction with other applicable emissions increases and decreases from existing sources, will not cause or contribute to a violation of any applicable NAAQS or *PSD increment*. Ambient impacts of noncriteria pollutants must also be evaluated if they exceed major source thresholds.

NAAQS and PSD Increments

NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations) and the modeled ambient impact caused by the applicant's source after completion of the major modification.

A *PSD increment*, on the other hand, is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

Class I, II and III Areas

PSD requirements provide for a system of area classifications that affords states an opportunity to identify local land use goals. There are three area classifications. Each classification differs in terms of the amount of growth it will permit before significant air quality deterioration would be deemed to occur:

- Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration.
- Class II areas can accommodate normal well-managed industrial growth.
- Class III areas have the largest increments and thereby provide for a larger amount of development than either Class I or Class II areas.

Congress established certain areas, including wilderness areas and national parks, as mandatory Class I areas. These areas cannot be re-designated to any other area classification. All other areas of the country were initially designated as Class II. Procedures exist under the PSD regulations to re-designate the Class II areas to either Class I or Class III, depending upon a state's land management objectives.

Unique Analyses Required

A separate air quality analysis must be submitted for each regulated pollutant. Each air quality analysis will be unique, due to the variety of sources and meteorological and topographical conditions that may be involved. Nevertheless, the air quality analysis must be accomplished in a manner consistent with the requirements set forth in either EPA's PSD regulations[ix] or a state or local PSD program approved by EPA.[x] Generally, the analysis will involve:

- an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results; and
- predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

Considerable guidance on collecting and analyzing ambient monitoring data and in performing air dispersion modeling is contained in EPA publications.[xii] [xiii]

Ambient Data Requirements

An applicant must provide an ambient air quality analysis that may include pre-application monitoring data, and in some instances post-construction monitoring data, for any pollutant proposed to be emitted by the new source or modification. In theory, this requirement could require the applicant to establish and operate a site-specific monitoring network for the collection of ambient pollutant and meteorological data. However, the available data collected by the State is usually sufficient.

Air Quality Modeling
Because of the complex character of the air quality analysis and the site-specific nature of the modeling techniques involved, applicants are advised to review the details of their proposed modeling analysis with the appropriate reviewing agency before a complete application is submitted. This is best done using a modeling protocol. The modeling protocol should be submitted to the reviewing agency for review and approval prior to commencing any extensive analysis.

Dispersion models are the primary tools used in the air quality analysis. These models estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The applicant should consult with the permitting agency to determine the particular requirements for the modeling analysis to assure acceptability of any air quality modeling techniques used to perform the air quality analysis.

Additional Impacts Analysis
In addition to preparing an air quality analysis, applicants must prepare an *additional impacts analysis* for each pollutant subject to regulation under the CAA. This analysis assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Other impact analysis requirements may also be imposed on a permit applicant under local, state or federal laws that are outside the PSD permitting process. Receipt of a PSD permit does not relieve an applicant from the responsibility to comply fully with such requirements. For example, two Federal laws that may sometimes apply are the Endangered Species Act and the National Historic Preservation Act. The regulations implementing these Acts may require additional analyses (although not as part of the PSD permit) if any federally-listed rare or endangered species, or any site that is included (or is eligible to be included) in the National Register of Historic Sites, are identified in the source's impact area.

Although each applicant for a PSD permit must perform an additional impacts analysis, the depth of the analysis generally will depend on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area. It is important that the analysis fully document all sources of information, underlying assumptions, and any agreements made as a part of the analysis.

Generally, small emissions increases in most areas will not have adverse impacts on soils, vegetation, or visibility. However, an additional impacts analysis still must be performed. Projected emissions from both the new source or modification and emissions from associated residential, commercial, or industrial growth are combined and modeled for the impacts assessment analysis.

Non-Attainment Area (NAA)

The pre-construction review requirements for major sources locating in NAA differ from PSD requirements:

- The emissions control requirement for non-attainment areas, Lowest Achievable Emission Rate (LAER), is defined differently than the BACT.
- Before construction of a non-attainment area source can be approved, the source must obtain emissions reductions (offsets) of the non-attainment pollutant from other sources that impact the same area as the proposed source.
- The applicant must certify that all other sources owned by the applicant in the state are complying with all applicable requirements of the CAA, including all applicable requirements in the state implementation plan (SIP).
- Sources impacting visibility in mandatory Class I federal areas must be reviewed by the appropriate federal land manager.

Many of the elements and procedures for source applicability under the non-attainment area NSR applicability provisions are similar to those of PSD applicability. See the section on "Prevention of Significant Deterioration (PSD)" for definitions of key terms and requirements common to both the PSD and NAA programs. However, important differences occur in three key elements in the applicability determinations:

- Location;
- Definition of *source*; and
- Applicability thresholds

Location

Whereas PSD applies in attainment areas, NAA applies in non-attainment areas. A NAA area is one formally designated by a state as *non-attainment* for a given criteria pollutant.[xiv] A *non-attainment area* is an area that does not meet NAAQS for a given pollutant.[xv] As noted previously, a source's location can be attainment or unclassified for some pollutants and simultaneously non-attainment for others.

Definition of Source

EPA gives states the option of adopting a *plant-wide* definition of stationary source in non-attainment areas, if the state's SIP did not rely on the more stringent *dual* definition in its attainment demonstration. Consequently, there are two stationary source definitions for non-attainment major source permitting: a *plant-wide* definition and a *dual* source definition. The permit application must use, and be reviewed according to, whichever of the two definitions is used to define a stationary source in the applicable SIP.

The EPA definition of stationary source for non-attainment major source permitting uses the *plant-wide* definition, which is the same as that used in PSD. In essence, this definition provides that only physical or operation changes that result in a significant net emissions increase <u>at the entire plant</u> are considered a major modification to an existing major source.

The *dual* definition of stationary source defines the term *stationary source* as ". . . any building, structure, facility, or installation which emits or has the potential to emit any air pollutant subject to regulation under the Clean Air Act." Under this definition, the three terms *building*, *structure*, or *facility* are defined as a single term meaning <u>all</u> of the pollutant-emitting activities which belong to the same industrial grouping (i.e., same two-digit SIC code), are located on one or more adjacent properties, and are under the control of the same owner or operator. The fourth term, *installation*, means an identifiable piece of process equipment. Therefore, a stationary source is both a building, structure, or facility (plant-wide); and an installation (individual piece of equipment).

In other words, the *dual* source definition of stationary source treats each emissions unit as (1) a separate, independent stationary source, and (2) a component of the entire stationary source. Consequently, under the *dual* source definition, the emissions from each physical or operational change at a plant are reviewed both with and without regard to reductions elsewhere at the plant.

Applicability Thresholds
For the purposes of non-attainment NSR, a major stationary source is generally:

- any stationary source which emits or has the potential to emit 100 TPY of any criteria pollutant; or
- any physical change or change in method of operation at an existing non-major source that constitutes a major stationary source by itself.

Note that the 100 TPY threshold applies to all sources, unless a lower level is used as follows:

- For ozone non-attainment areas, the major source threshold is 50 TPY in areas designated as in “serious” non-attainment, 25 TPY in “severe” areas, and 10 TPY in “extreme” areas;
- For PM-10[71] non-attainment areas the major source threshold is 70 TPY for designated as in “serious” non-attainment; and
- For carbon monoxide non-attainment areas the major source threshold is 50 TPY for designated as in “serious” non-attainment.

The alternate 250 TPY major source threshold (for PSD sources not classified under one of the 28 regulated source categories) which applies in attainment areas does not exist for non-attainment area sources.

Major modification thresholds for NAA are those same *significant* emissions values used to determine if a modification is major for PSD (see Table 3).

Lowest Achievable Emissions Rate (LAER)
Lowest Achievable Emissions Rate (LAER) is the control level required of a source subject to non-attainment review. From the regulations,[xvi] LAER means for any source "the more stringent rate of emissions based on the following:

a) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

b) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate of the new or modified emissions units within a stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance."

[71] Particulate matter with an aerodynamic diameter less than 10 microns.

Emissions Offsets

A major source or major modification planned in a non-attainment area must obtain emissions reductions as a condition for approval. The offset requirement applies to each pollutant that triggered NAA applicability. These emissions reductions, generally obtained from existing sources located in the vicinity of a proposed source, must:

- offset the emissions increase from the new source or modification; and
- provide a net air quality benefit.

The obvious purpose of acquiring offsetting emissions decreases is to allow an area to move towards attainment of the NAAQS while still allowing some industrial growth. Air quality improvement may not be realized if all emissions increases are not accounted for and if emissions offsets are not real.

Offsets must be developed in accordance with the provisions of the applicable state or local non-attainment NSR rules. The following factors are considered in reviewing offsets:

- the pollutants requiring offsets and amount of offset required;
- the location of offsets relative to the proposed source;
- the allowable sources for offsets;
- the baseline for calculating emissions reduction credits; and
- the enforceability of proposed offsets.

Each of these factors should be discussed with the reviewing agency to ensure that the specific requirements of that agency are met.

New Source Performance Standards (NSPS)

Introduction

The EPA is required to establish and periodically revise New Source Performance Standards (NSPS) to primarily control emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2) and particulate matter (PM_{10}) from various types of facilities.[72] Parts relevant to CHP include:

- Subpart Da (applicable to electric utility steam generating units with heat input greater than 250 Million British Thermal Units (MMBtu)/hour);
- Subpart Db (applicable to industrial, commercial or institutional steam generating units with heat input greater than 100 MMBtu/hour and less than 250 MMBtu/hour);
- Subpart Dc (applicable to industrial, commercial or institutional steam generating units with heat input greater than 10 MMBtu/hour and less than 100 MMBtu/hour); and
- Subpart GG (applicable to stationary gas turbines with heat input greater than 10 MMBtu/hour).

Standards of performance for new sources are to reflect the application of the best system of emission reduction that (taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impact and energy requirements) the EPA determines has been adequately demonstrated. This level of control is commonly referred to as Best Demonstrated Technology (BDT).

[72] The NSPS are codified in 40 CFR Part 60.

NSPS applied to new sources of modification of existing sources, the latter being any physical or operational change to an existing emission unit subject to NSPS that results in an increase in emissions. Changes to an existing emission unit subject to NSPS that do not result in an increase in emissions, either because the nature of the change has no effect on emissions or because additional control technology is employed to offset an increase in emissions, are not considered modifications. In addition, certain changes have been exempted, including production increases resulting from an increase in the hours of operation, addition or replacement of equipment for emission control (as long as the replacement does not increase emissions), and use of an alternative fuel if the existing facility was designed to accommodate it.

Existing steam generating units would become subject to NSPS if the fixed capital cost of reconstruction exceeds 50 percent of the cost of an entirely new steam generating unit of comparable design and if it is technologically and economically feasible to meet the applicable standard.

Recent revisions to NSPS
The EPA most recently revised the NO_X emission rates in certain NSPS in September 1998. These revisions for steam generating units included several important changes:

- emissions standards are fuel neutral,
- utility boiler standard is based on the electric output, rather than fuel input, and
- systems that cogenerate steam and electricity are also treated on an output basis.

The new NO_X emission limits are:

- for newly constructed subpart Da units, 1.6 pounds (lbs.)/megawatt-hour (MWh) gross energy output regardless of fuel type;[73]
- for existing sources that become subject to subpart Da through modification or reconstruction, 0.15 lb./million Btu (MMBtu) heat input;
- for subpart Db units, 0.20 lb./MMBtu heat input from the combustion of natural gas, oil, coal, or a mixture containing any of these fossil fuels, except for low heat release rate units; and
- for low heat release rate units firing natural gas or distillate oil, 0.10 lb./MMBtu.

EPA's ongoing Industrial Combustion Coordinated Rulemaking (ICCR) could eventually result in the EPA extending the applicability of subpart GG to the duct burner used in waste heat boilers, which is currently covered by subparts Da and Db. The EPA agrees that if this were to occur, the ICCR-driven revisions to subpart GG would pose a potential conflict with the subparts Da and Db. EPA has stated that it will revise subparts Da and Db to exempt sources that may also become subject to subpart GG, should such revisions to subpart GG occur.[xvii]

EPA based the revised NO_x emission limits for electric utility boilers and industrial boilers on coal-firing and the performance of Selective Catalytic Reduction (SCR) control technology, in combination with combustion controls. The EPA's analysis indicates that Selective Catalytic Reduction (SCR) can reduce NO_x emissions from coal-fired units to 0.15 lb/million Btu heat input. For oil-fired units, Selective Non-Catalytic Reduction (SNCR) in combination with combustion controls would be able to achieve this level. New gas-fired units may require some degree of SNCR if improved combustion controls alone are unable to achieve this level.

[73] One MWh of thermal energy equals 3.413 Million Btu.

EPA has stated that new gas-fired and distillate oil-fired industrial units would not require any additional controls over those required under the current NSPS. Technology requirements for new coal-fired units were not addressed.

Quantifying Output in CHP facilities

For the output-based standards, output must be actual output, measured at the busbar or its thermal equivalent, the steam header supplying the industrial process loads or district energy system. The NSPS require that the thermal output in a CHP facility be discounted by 50 percent. One million Btu of thermal energy is equal to 293 kilowatt-hours thermal (kWh_{th}). However, the NSPS requires that the heat output be counted, for the purposes of application of the output-based standard, at only 50 percent of this level. EPA's rationale was that crediting more than 50 percent might result in artificially high output rates, or might require complex monitoring. However, in issuing the final revisions, EPA acknowledged that "there may be alternative ways of calculating the value of thermal output that warrant further consideration. We are interested in exploring alternative approaches to cogeneration and request further comment on this issue." [xviii]

Emissions Trading

Cap and Trade Systems

Cap and trade programs are increasingly used to reduce overall emissions. The following discussion is not intended to cover this topic comprehensively, but to provide an overview of key emissions trading programs likely to affect CHP facilities.

Cap and trade regulation begins with a *cap*–a limit on the tons of a pollutant that can be emitted in a specific period for a specific sector and/or region. A cap is sometimes called an *emission budget*. *Allowances*–permissions to emit a ton of a specific pollutant–are then issued to emission sources. The source must turn in allowances equal to their actual emissions for each period.

A key issue in cap and trade is the way that allowances are allocated. Options include:

- Auctioning the allowances;
- "Grandfathering" based on historical emissions; or
- Allocation based on applying an emission rate per unit of output time historical or projected generation.

An individual generator can chose to comply by:

- limiting its emissions to an amount equal to the allowances it has received;
- purchase additional allowances in the market to cover emissions exceeding the allowances it was allocated; or
- overcomply and sell the excess allowances.

Sulfur Dioxide Trading

Title IV of the amendments to the CAA was designed to reduce acid rain by limiting emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Title IV is implemented through a system of marketable sulfur dioxide emission allowances. Each affected source is allocated a specific number of allowances based on past emission rates and utilization. Once allocated, the allowances may be bought, sold, traded or banked for use in future years. At the end of each compliance year, the participating facility must retire one allowance for each ton of SO_2 emitted in the previous year. As of the year 2000, Title IV is applicable to power plants generating more than 25 MW electricity for sale, or to industrial plants that "opt in" to the program.[xix]

Nitrogen Oxides

The cap and trade approach is also being implemented for control of Nitrogen Oxides (NO_X) as a strategy for controlling summertime ground-level ozone. In October 1998 the EPA finalized a rule commonly called the "NO_X SIP Call," which requires 22 States and the District of Columbia to submit revised State Implementation Plans (SIPs) that address the regional transport of ground-level ozone through reductions in NO_X.[xx] This rule is part of EPA's response to petitions filed by eight northeastern States seeking to reduce ozone across State boundaries.

This rule is significant for the regional approach taken to emission control, and because it authorizes a NO_X cap and trade program. Each affected state has been assigned a cap on seasonal NO_X emissions, based on estimates of emissions that would occur in the year 2007. States have the option of allowing sources to meet obligations through emissions trading. The rule contains a model trading program applicable to larger sources.[xi]

EPA also proposed federal requirements including a trading program to reduce regional ozone transport in these states if any state does not submit the required SIP provisions in response to the NO_X SIP call.

The final rule does not mandate which sources must reduce pollution. States will have the ability to meet the requirements of this rule by reducing emissions from the sources they choose. However, utilities and large non-utility point sources (power plants over 25 MW_e or boilers over 250 MMBtu/hour fuel input) would be one of the most likely sources of NO_X emissions reductions and is the focus of the default federal requirements.

A key issue is the process for allocating NO_X emission credits. EPA has proposed that this be done on the basis of fuel input. However, EPA has undertaken an investigation into how to approach the allocation process based on energy output and has developed guidance on issuing output-based allocations for the NO_X trading program.[xxii]

Other Emission Trading Initiatives

Cap and trade has also been discussed as a potential future tool for controlling regional haze and emissions of carbon dioxide (CO_2).

Regional Haze. Fine particulate matter pollution contributes to regional haze, which is a particular issue for national parks. Fine particulate matter includes sulfate and nitrate particles formed in the atmosphere from SO_2 and NO_X. In April 1999, EPA finalized a rule that will require states to develop plans to essentially eliminate haze conditions in national parks.[xxiii] States that opt to use emissions trading will develop plans for submission to EPA.

Carbon dioxide. The Kyoto Protocol[74] provides for control of greenhouse gases (GHG) through emissions trading. The actual principals, rules and guidelines for emissions trading are to be decided at future Conferences of the Parties (COPs). Specifically, Article 17 of the Kyoto Protocol states: "The Conference of the Parties shall define the relevant principles, modalities,

[74] The United Nations Framework Convention on Climate Change (FCCC) was adopted on 9 May 1992, and was opened for signature at the UN Conference on Environment and Development in June 1992. The Convention entered into force on 21 March 1994, 90 days after receipt of the 50th ratification.

rules and guidelines, in particular for verification, reporting and accountability for emissions trading."

At the same time that the broader framework for international trading is being established, individual countries, or groups of countries (such as the European Union), are exploring how to implement trading of GHG within their borders. The US has not established a process or forum for discussion of GHG trading because of the political controversy surrounding the Kyoto Protocol in Congress. However, the approach to NO_X trading as established in the NO_X SIP call suggests some elements of a potential US domestic trading system for GHG.

Permitting Process

This section outlines a recommended five-step permit drafting process (summarized in Table 2), as set out by EPA in a draft guidance document.[xxiv] These steps can assist the project writer in the orderly preparation of air emissions permits following technical review.

Table 4
Five Steps to Permit Drafting

Step 1. Specify Emissions Units

- Identify each new (or modified) emissions unit that will emit (or increase) any pollutant.
- Identify any pollutant and emissions units involved in a netting or emissions reduction proposal (i.e., all contemporaneous emissions increases and decreases).
- Include point and fugitive emissions units.
- Identify and describe emissions unit and emissions control equipment.

Step 2. Specify Pollutants

- Pollutants subject to NSR/PSD.
- Pollutants not subject to NSR/PSD but could reasonably be expected to exceed significant emissions levels. Identify conditions that will ensure that emissions do not exceed levels considered significant (e.g., shutdowns, operating modes, etc.).

Step 3. Specify Allowable Emission Rates and BACT/LAER Requirements

- Minimum number of allowable emissions rates specified is equal to at least two limits per pollutant per emissions unit.
- One of two allowable limits is unit mass per unit time (lbs/hr) which reflects application of emissions controls at maximum capacity.
- Maximum hourly emissions rate must correspond to that used in air quality analysis.
- Specify BACT/LAER emissions control requirements for each pollutant/emissions unit pair.

Step 4. Specify Compliance Demonstration Methods

- Continuous, direct emission measurement is preferable.
- Specify initial and periodic emissions testing where necessary.
- Specify surrogate (indirect) parameter monitoring and recordkeeping where direct monitoring is impractical or in conjunction with tested data.
- Equipment and work practice standards should complement other compliance monitoring.

Step 5. Other Permit Conditions

- Establish the basis upon which permit is granted (legal authority).
- Should be used to minimize "paper" allowable emissions.
- Federally enforceable permit conditions limiting potential to emit.

Step 1 concerns the emissions units and requires the listing and specification of three things. First, list each new or modified emissions unit. Second, specify each associated emissions point. This includes fugitive emissions points (e.g., seals, open containers, inefficient capture areas, etc.) and fugitive emissions units (e.g., storage piles, materials handling, etc.). Be sure also to note emissions units with more than one ultimate exhaust and units sharing common exhausts.

Third, the writer must describe each emissions unit as it may appear in the permit and identify, as well as describe, each emissions control unit. Each new or modified emissions unit identified in Step 1 that will emit or increase emissions of any pollutant is considered in Step 2.

Step 2 requires the writer to specify each pollutant that will be emitted from the new or modified source. Some pollutants may not be subject to regulation or are present in amounts such that they do not require major source review. All pollutants should be identified in this step and reviewed for applicability. Federally enforceable conditions must be identified for pollutants that would not be considered significant to ensure they do not become significant. An understanding of "potential to emit" is pertinent to permit review and especially to the drafting process.

Step 3 pools the data collected in the two previous steps. The writer should specify the pollutants that will be emitted from each emission unit and identify associated emission controls for each pollutant and/or emission unit. (Indicate if the control has been determined to be BACT.) The writer also must assess the minimum number of allowable emissions rates to be specified in the permit. Each emissions unit should have at least two allowable emissions rates for each pollutant to be emitted. This is the most concise manner in which to present permit allowable rates and should be consistent with the averaging times and emissions ratio used in the air quality analysis. The applicable regulation should also be cited as well as whether BACT, LAER, or other State Implementation Plan requirements apply to each pollutant to be regulated.

Step 4 addresses any performance testing required of the source. The conditions should specify what emissions test is to be performed and the frequency of testing. Any surrogate parameter monitoring must be specified. Recordkeeping requirements and any equipment and work practice standards needed to monitor the source's compliance should be written into the permit in Step 4. Any remaining or additional permit conditions, such as legal authority and conditions limiting potential to emit can be identified in Step 5.

Step 5 At this point, the permit should be complete. The writer should review the draft to ensure that the resultant permit is an effective tool to monitor and enforce source compliance. Also, the compliance inspector should review the permit to ensure that the permit conditions are enforceable as a practical matter.

References

i. Section 107 of the Clean Air Act (CAA) and 40 CFR 81.
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vi. 40 CFR 52.21(b)(4), 51.165(a)(1)(iii), and 51.166(b)(4).
vii. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, U.S. Environmental Protection Agency.
viii. 40 CFR 52.21(b)(23).
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xix. U.S. Environmental Protection Agency, "Acid rain Program, Propose Opt-In Provisions," EPA 430-F-93-013, Sept. 1993.
xx. 63 Federal Register 57356-57504 (October 27, 1998). See also, Proposed Rule, 62 Federal Register 60317 (November 7, 1997); and Supplemental Proposed Rule, 63 Federal Register 25901 (May 11, 1998).
xxi. 63 Federal Register 57356, 57456 (October 27, 1998).
xxii. U.S. Environmental Protection Agency, "Developing and Updating Output-Based NOx allowance Allocations, Guidance for States Joining the NOx Budget Trading Program under the NOx SIP Call," May 8, 2000.
xxiii. 64 Federal Register 35714 (July 1, 1999); 40 CFR Part 51, subpart P, 51.308 and 51.309.
xxiv. "New Source Review Manual," Draft Guidance document, U.S. Environmental Protection Agency, October 1990.

Siting of Electricity-Generating Facilities

Introduction

Siting major facilities has become very controversial over the past two decades. Not-in-My-Back-Yard (NIMBY) and BANNA (Build Absolutely Nothing Near Anyone) sentiments increasingly slow or stop freeway projects, airport expansions, construction of correctional facilities, and the development of energy facilities.

During the era of large utility power plant development (400-1,000+ MW coal, oil, and nuclear facilities), many states passed comprehensive facility siting statutes, often preempting local jurisdictions. These statutes were enacted primarily to protect the public health and safety, for promotion of the general welfare, and to provide environmental quality protection. They were also designed to ensure consistency in the evaluation process and to facilitate the siting and development of generation facilities deemed to be needed and in the public interest. The passage of many of these statutes was a direct result of the energy crises of the 1970s and of a need to replace a system that was fragmented and that did not consider environmental and land use issues. A system that divided authority among federal, state, and local authorities; and a system where developers could spend years submitting applications and meeting various agency permit requirements, some that often changed before ground breaking could even take place. Many agencies, in fact, had no requirement to process a permit application within a specified time period. The site certification process many states adopted was designed to provide a so called one-stop application process that would eliminate duplication of effort and regulatory uncertainty by providing one regulatory permit; a time-certain decision, simultaneous review, and participation by all state and local agencies; coordination with federal agencies; and full opportunity for the public and special interest groups to participate.

Some of these statutes covered all electrical facilities, regardless of technology or size, while others dealt only with thermal facilities over a certain threshold, e.g., 25, 50, or even 250 MW. Some, but not all, state siting statutes dealt with associated facilities including transmission lines, fuel pipelines, and fuel storage as well as waste storage facilities, i.e., nuclear materials. Most statutes required a finding of need, although there were major exceptions. For example, the Washington State statute assumes that a need for power exists and therefore provided no mechanism to ensure that projects built would be consistent with regional, state, or local utility planning (California, on the other hand, specifically mandated an integrated needs assessment and placed central planning authority with the California Energy Commission).

The siting statutes adopted by the states were, for the most part, successful in ensuring that electrical generation facilities could be built in a timely manner to meet projected load growth, and that the projects were both needed and environmentally acceptable. Even the appeals process was expedited with appeals often going directly to the state supreme court.

The question now, however, is: can a system designed to meet the needs of the utility industry of the 1970s and 1980s adequately meet current needs considering the following industry trends: a move from central to decentralized facilities; from large plants (400 MW to 1,000+ MW) to smaller plants (often less than 50 MW); from nuclear, coal, and oil to natural gas and renewables; where new generation is more likely to be built by non-utility energy companies than by utilities, and where merchant plants are being built to supply state or even regional needs rather than plants designed to meet the specific projected needs of a given utility or a consortium of utilities?

Facility Siting

Scope and Definition of Terms

As used herein, "facility siting" means the land-use and environmental review process used to physically situate an energy facility at a specific location (or linear location in the case of transmission lines). The "need" for siting a facility is usually linked to a market need for power or transmission capacity, and since "need," if a determinant, is normally established at the state level, it is not included within this examination of siting as essentially a land-use and environmental review action.

Energy facility siting is the complex and controversial land-use and environmental decision to physically situate a facility in a given location. Public resistance to many types of unwanted land-uses, including power plants, transmission lines, and sub stations, is a major force that increasingly challenges the reliability of infrastructure planning and development. Facing this largely hostile public is often a two-tiered energy facility siting system: 1) in many states, consolidated state-level siting of large facilities, e.g., >50 MW, that preempts the jurisdiction of local government's and other state permitting agencies; and 2) for smaller facilities, e.g., <50 MW, (and, in some states, large facilities), lead siting by local government in conjunction with other permitting agencies (Table 1). And, in fact, many states do not have siting statutes or siting agencies. In these states, siting will be predominantly a local issue, although state and federal regulation of such things as water quality and air emissions will most often be under the jurisdiction of state agencies and transmission, at least intrastate transmission, is likely to be under the jurisdiction of the FERC (Federal Energy Regulatory Commission).

Many states' facility siting statutes contain thresholds of 50 to 250 MW below which state siting does not apply; in other states, siting statutes apply only to utility-constructed facilities. Recent changes in siting statutes in Montana (1997), where the threshold was raised from 50 to 250 MW, and in Oregon (1999), where high-efficiency plants can be exempted from state siting, would tend to indicate that more and more generation facilities will once again be required to obtain all needed permits from a variety of state, local, and federal single-purpose agencies with local jurisdictions having ultimate land use siting authority (see Appendix A). In California, SB 110, enacted in 1999, removed the CEC's ability to conduct "integrated needs assessments" and the CEC's central planning authority. These changes that are coming as a result of, for the most part, deregulation of the electricity industry and a philosophy of let the market decide, could have a profound impact on energy facility siting in general, and on the environment, in particular, as local jurisdictions do not have the authority or mandate to consider the cumulative environmental or economic impacts of facilities sited throughout a state or region. Appendix A provides examples of statutes and regulations affecting energy facility siting.

Since a large majority of combined heat and power (CHP) projects are expected to be under 50 MW, it would now appear that most such projects will be sited under the jurisdiction of local governments and not enjoy the benefit of a one-stop siting process.

But are local jurisdictions really well equipped to meet the challenge? Will independent power project developers have the financial resources and staying power needed to navigate the maze of local, state, and federal agency permit requirements? How will local jurisdictions deal with, and what impact will almost certain public opposition to many projects have on distributed generation development and, in particular, on CHP developments that must necessarily be sited in close proximity to thermal hosts including industrial, institutional, and commercial facilities? And who will be responsible for dealing with the cumulative impacts of widespread development of electrical generating facilities on water resources, air quality, and/or endangered species?

The objective of this portion of the guide is to:

- Investigate whether local government siting of electric energy facilities is a potential impediment to meeting state, regional, and national energy needs.
- Assess the need for and possible ways to improve local capabilities?

Approach

Preparation of this section has included the following steps:

- A review of siting laws and literature.
- Telephone and personal interviews with agency staff and power developers.

The survey efforts were intended to solicit anecdotal opinions and experiences that can be used to guide subsequent activities directed toward addressing the needs of facility siting.

Significance of the Issue

For over a decade, the power industry has been trending towards smaller increments of generation and transmission development as the industry has become more segmented and competitive. The advent of independent power production has been a major contributing factor in this regard as have the advent of distributed generation and combined heat and power. Most recently, electricity utility industry restructuring and deregulation have caused more and more entities from retail outlets to college campuses to consider CHP as a way to stabilize energy costs and industrial complexes to achieve energy reliability and security.

These trends are leading to greater siting responsibilities for local governments because the number of new electrical generating facilities is increasing, and the size of these facilities is often falling beneath state siting statute thresholds that preempt local governments.

Local governments, therefore, are becoming much more significant for several reasons:

- Complexity of the institutional setting. Because of the number of cities and counties along with dozens of federal and state environmental and energy agencies who are, in turn, monitored by many energy and environmental interests groups, the involvement and competence of participating organizations becomes all the more important.

- Constrained local resources. Most local governments are operating under ever more severe budget and staff limitations. In addition, local government staff rarely possess specialized energy facility siting expertise, and their elected officials are usually equally unfamiliar with energy facility siting policy and decision-making. This lack of experience is further exacerbated by the high turnover typical among local elected officials.

- Public acceptance of current generation trends. Two power generation trends that are increasing local siting pressures are distributed generation and, in particular, industrial, commercial, and institutional combined heat and power (CHP). The latter often poses the difficulties of siting facilities in densely-populated urban settings (even though some may be industrially zoned); and the former is often co-located with commercial or even residential development. In either case, negative citizen reaction is usually pronounced, further increasing performance pressures on local officials.

- Forum shopping by developers. The mix of limited local resources and public hostility sometimes leads power developers to shop for the friendliest siting forum, i.e., a local jurisdiction anxious for a short-term economic boost and willing to help the developer deflect public opposition while applying minimal facility siting standards. This is not only counterproductive for the public and the affected environment, but it also encourages power plant sizing and siting for the sake of local expediency rather than achievement of broader state, regional, or even national energy goals.

- BANNA and NIMBY phenomena affect all types of facilities. Virtually every new energy facility will face some form of organized opposition. Experience across the nation indicates that as many as 25 percent of proposed facilities will be defeated in the siting process by opponents. Research indicates the high defeat rate is often due to weak local resources for handling organized opposition. It is reasonable to conclude that the number of defeats can be reduced in proportion to increases in siting capability building among local jurisdictions. This, in turn, should simultaneously strengthen grass-root acceptance of facilities in general, including larger projects that will continue to fall under state siting jurisdictions where applicable.

- High siting costs. Contentious, lengthy siting processes have significant economic and social costs, the former ultimately resulting in higher electricity costs or lost opportunities for the development of cost-effective generation, and the latter degrading a community's cohesiveness, regardless of the issue. Local capability building can reduce both the dollar cost and the social divisiveness associated with meeting energy needs.

Among these issues, effective public involvement appears to be one of the most problematic. The difficulties of dealing with uninformed or misinformed citizen, and organized citizen opposition, were the most consistent observation found during the literature review and through the interview process. Although considerable research has been conducted on the problem, and federal and state agencies regularly conduct extensive involvement efforts, on the local government level this remains a major weakness. Few local jurisdictions have public involvement standards and procedures for major projects such as energy facilities. Further, they rarely have trained staff to facilitate or negotiate complex projects among strongly adversarial groups.

If communities are not adequately equipped for their siting responsibilities, the states and nation would seem to incur three notable risks: 1) facility sites may be denied because of emotional local opposition rather than for substantive technical reasons; 2) developers may purposely seek out jurisdictions with weak regulatory postures; and/or 3) facilities may be sited with minimal review and mitigation, causing environmental problems and further erosion of public support for energy facilities generally.

This circumstance is not unique or new to any particular state or region in the country. The significance of facility siting problems and the need for remedies has been consistently reflected in the National Conference of State Legislature's annual nationwide issue survey. As early as 1990 and for several years thereafter; the number one-ranked energy/environmental problem was facility siting. In 1993, the U.S. Department of Energy published *Energy Infrastructure of the United States and Projected Siting Needs: Scoping Ideas, Identifying Issues and Options: Draft report of the Department of Energy Working Group on Energy Facility Siting to the Secretary* (DOE/PO-0005 Draft Report 12/93). A major finding of the report was that "effective energy facility siting policies can accelerate national economic growth, speed up the availability of clean fuels, and advance environmental programs." The report also concluded that "each facility has its own set of characteristics and faces its own unique set of constraints, and would have to be evaluated individually." Yet one thing did seem certain: siting is becoming more difficult for all types of facilities. Siting inefficiencies cause, at a minimum, service delays that result in adverse economic, environmental, and energy impacts. In certain cases, the siting process does not proceed at all and disrupts the development of needed local, state, and national infrastructure. It is also clear that market forces alone, without additional direction or new incentives, cannot be relied upon to 'solve' these problems."

State Practices

States

In general, most states with facility siting statutes preempt local governments above a facility-size threshold, e.g., 50 MW, and do not grant any special standing for local government in cases of preemption (see Table 5). A few states offer technical assistance to localities exercising lead responsibilities for siting smaller facilities. The strongest effort has been administered in California where the California Energy Commission has provided financial and technical support to cities and counties for conducting energy resource inventories, establishing resource and technology policies, adopting siting standards, and conducting siting studies. Another noteworthy state is Maryland, where communities can be assisted by the Power Plant Research Program that conducts independent technical evaluations of facility proposals on behalf of localities or the state.

In the Pacific Northwest states, only Idaho lacks a local government preemption threshold; however, nationally only a percentage of the states have state siting statutes, and of these, the thresholds vary greatly. The following is a list of states with siting statutes and thresholds for state preemption (Table 5). It should be pointed out that although the state may exercise some or even total siting authority, it may not provide for a consolidated permit and, in fact, many site certificates are granted only after required state and local permits have been obtained (see Appendix A).

Table 5
State Jurisdictional Thresholds for
State Preemption of Local Governments

State	Power Plants (MW)	Transmission Line (kV)
Alabama	NA	NA
Alaska	NA	NA
Arizona	100	115
Arkansas	ALL	160
California	50	*
Colorado	NA	NA
Connecticut	ALL	69
Delaware	NA	NA
Florida	75	230
Georgia	NA	NA
Hawaii	NA	NA
Idaho	NA	NA
Illinois	NA	NA
Indiana	NA	NA
Iowa	25	34
Kansas	100	230
Kentucky	ALL	NA
Louisiana	NA	NA
Maine	NA	NA
Maryland	ALL	69
Massachusetts	100	69
Michigan	NA	345
Minnesota	80	200
Mississippi	ALL	NA
Missouri	NA	NA

State	Power Plants (MW)	Transmission Line (kV)
Montana	250	69
Nebraska	NA	200
New Hampshire	30	100
Nevada	NA	NA
New Jersey	100	NA
New Mexico	NA	NA
New York	80	*
North Carolina	300	161
North Dakota	50	115
Ohio	50	125
Oklahoma	NA	NA
Oregon	25	230
Pennsylvania	NA	NA
Rhode Island	40	69
South Carolina	75	125
South Dakota	100	250
Tennessee	NA	NA
Texas	NA	NA
Utah	NA	34
Vermont	ALL	ALL
Virginia	100	150
Washington	250	200
West Virginia	NA	200
Wisconsin	100	100
Wyoming	ALL	ALL

*Transmission lines for project to first point of interconnection.
ALL = State has jurisdiction over all electrical generation facilities although some exceptions may be granted.
NA = Either state does not have a siting statute or information concerning statute was not received from the state.

Additionally, a state-level examination of siting that provides valuable insights into the formulation of procedures and standards is the so-called Keystone model developed in 1992 and named after the conference center in Colorado where it was collaboratively developed. Appendix C summarized its approach to developing a state siting act (also see Keystone 1992, in References).

Developers should always contact the appropriate state and local agencies prior to initiating any project. It should be noted that state siting thresholds and procedures have recently been revised in a number of states--Oregon, California, and Nevada being prime examples--and are presently undergoing review and revision in many other states. Because of this, legal provisions, as described here, may be superseded by new legislation in the near future, and the reader is advised to contact the particular state for a copy of current statutes and implementing rules and regulations.

These are generalized expressions of the thresholds; each is subject to certain conditions and exceptions and the list should only be used as a general guide. In many states, various systems associated with a generating facility also fall under the jurisdiction of the state entity responsible for facility siting. Associated facilities include, but are not limited to, transportation lines of any kind and can include oil, gas, and even geothermal pipelines and, of course, transmission lines. Gas storage facilities, waste storage facilities, petroleum refineries, uranium enriching facilities, and coal gasification facilities can be subjected to state siting statute provisions. In none of the states for which information was available, did facility jurisdiction extend to hydro facilities, but in at least some jurisdictions covered even major photovoltaic arrays (e.g., over 100 acres in Oregon). In most, but not all, states associated systems were only under jurisdictions of the state process if they were directly connected to a power plant that was also under state siting authority. For example, in Washington, only transmission lines of 200 kV or greater connecting a thermal facility to the northwest power grid would be affected. In other states, although the threshold may be as low as 69 kV, there are numerous exceptions to the rules. In some states, lines are exempt if they are, for example, less than 10 miles in length or, in some cases, 1 mile in length. Many lines are exempt if they use an existing right-of-way or are simply an upgrade of an existing line. In some states, use of an existing right-of-way is required unless it can be demonstrated that such use will not be suitable.

In some states, the threshold for jurisdiction is based on both size and cost as, for example, an expansion of an existing facility over a certain cost figure. Air emission over a predetermined limit can also trigger state jurisdictions as can any facility not employing best available control technologies. As with transmission lines, pipelines have numerous exceptions from state jurisdiction and diameter, length, and flow are all used as determinants of jurisdiction. Capacity is the most used criteria for determining jurisdiction on storage facilities and refineries.

One of the most controversial issues related to facility siting has been the question of need. Even in those states without a state siting authority, the state utility commission, or its equivalent, often is charged with making a determination of need, at least in the case of utility-sponsored projects. For the most part, since such bodies most often do not have regulatory authority over independent power producers and new developers of merchant power plants, the establishment of the need for any particular facility will be left unanswered except by the market place.

Local Governments

In order to assess local government circumstances, it is first necessary to examine state laws and practices that define the manner in which local governments discharge their siting responsibilities. There are two primary legal considerations in this regard:
State energy facility siting thresholds above which local government powers are preempted.

The extent of land-use powers granted to local governments by states, and the applicability of those powers specifically to energy facilities.

Most states authorize cities and counties to adopt land-use plans, development standards, and environmental regulations that may control, to varying degrees, energy facilities. Oregon's land-use system, for example, is one of the most rigorous, requiring local governments to thoroughly address energy resources, facility siting, and environmental protection. Other states have enacted land-use requirements for jurisdictions in high-growth areas. Localities in most other states have the ability, but not always the obligation, to address these issues in their plans and standards.

When acting as lead siting agencies, cities and counties exercise their authority primarily through the land-use powers described above, and in some cases, via public service and environmental compliance powers. Typical mechanisms for local siting include:

Comprehensive plans. These are broad policy plans covering topics such as land-use, housing, and transportation, which may or may not contain energy elements and siting policies, but which, nonetheless, will govern the overall acceptability of any facility.

Special purpose plans. These may be focused on jurisdiction-wide planning topics, e.g., open space, or a geographic subarea of a jurisdiction, e.g., a neighborhood plan.

Zoning ordinances. These reduce comprehensive and special-purpose plans to site-specific land-use designations, and detailed construction and operating standards. Facility siting and performance standards are normally codified within zoning ordinances.

Land development ordinances. These primarily affect electric transmission and distribution lines because they usually contain utility easement standards and construction requirements for utility services (see Appendix B).

Environmental compliance. Depending on the state, cities and counties administer a variety of federal, state, and local environmental regulations involving natural resource protection and public health and safety. In Oregon, for example, this is both a comprehensive planning obligation and regulatory responsibility. In Washington, local governments administer the State Environmental Policy Act, which requires preparation of environmental impact statements for projects having significant environmental impacts.

Public service ordinances. Some local governments control the provision or extension of critical services, e.g., water and sewer, as a means of managing growth and development. For example, a proposed power plant may need a wastewater line or fire protection that can only be approved if consistent with that locality's wastewater extension or fire protection policies.

It is suggested that there are the following three general categories of facility siting "readiness" among local governments:

Dated minimal energy facility regulation. This is the largest group, and is characterized by: 1) little or no consideration of energy facilities in comprehensive plan policies; and 2) zoning ordinance definition of energy facilities as generic "public utility structures" allowable in most locations with minimal siting requirements.

Recent restrictive measures focused on certain resources. This is the second largest group that, beginning in the late 1970s, began adopting modern standards in response to development pressures, e.g., power projects induced by the Public Utility Regulatory and Policy Act (PURPA). Many communities in this category have measures focused on particularly sensitive resources, e.g., hydro or geothermal.

Recent comprehensive economic and environmental strategies. This is a very small group of jurisdictions that, through local initiative and outside funding, have established full planning frameworks that promote sound energy development while safeguarding against detrimental development. A number of counties in California and Oregon, for example, have adopted comprehensive renewable policies and standards for these purposes.

The difficulty in assembling nation-wide local government data makes it nearly impossible to accurately quantify the sizes of these groups, but it is reasonable to estimate that the first group represents, by far, the majority of cities and counties in the nation.

Telephone interviews conducted in previous studies focused on projects where local jurisdictions were lead siting agencies. These interviews gave an impression of city and county resources either stretched thin, or, in some cases, completely lacking, when confronted with an energy facility siting proposal. The following problems and needs were mentioned most often:

- Technical information. Three types of technical information needs were cited: 1) current generation and transmission technologies, and their impacts and mitigation strategies; 2) long-range transmission corridor identification within and adjacent to the locality; and 3) local resources and facility sites that may be subjected to development pressures in the foreseeable future, e.g., high voltage transmission lines co-located with major natural gas pipelines, major industrial sites, institutional campuses, e.g., colleges and universities, hospitals, government complexes.

- Public information. A concurrent, but distinct, information need exists with the public and with local elected officials. The same types of information described above also needs to be available in non-technical terms for lay audiences.

- Processing staff. Most local jurisdictions have trouble keeping up with normal workloads, let alone the imposition of something as potentially complex as siting an energy facility. Because successful siting is critically dependent upon high levels of citizen participation, the need for trained and experienced process facilitators is often cited. There was also a desire expressed for more advance notice of a facility proposal, so that staffing and workload adjustments could be planned for and arranged.

- Analytical staff. This is another concurrent but distinct staffing need that requires environmental, scientific, and engineering skills beyond most local staff capabilities or expertise. Given judicial testing of most siting decisions, the need for competent technical evaluation of proposals is even more apparent.

- Hardware. Effective use of staff and information requires a certain amount of equipment support, whether it be computerized geographic information systems or environmental testing and monitoring equipment. As would be expected in today's budget climate, most local governments cannot afford to acquire or maintain elaborate decision-support equipment.

Woven into each of these problem/need categories are consistent expressions of frustration about the contentious, adversarial nature of facility siting. There is strong interest in developing siting process techniques that:

- Expand public involvement opportunities beyond normal land-use proceedings, particularly non-formal activities.

- Clearly distinguish between relevant and irrelevant issues at the outset of the process.

- Allow for negotiated development trade-offs to resolve conflicts, rather than rely on traditional litigation approaches.

Improving Local Siting

Relatively few cities and counties in the nation have up-to-date energy facility siting policies and standards. For years, most local governments nation-wide have treated energy facilities as essential utility infrastructure allowable in most locations. This is particularly true in many rural counties and small to moderate-sized cities.

If local governments' siting capabilities are to be improved, particularly their decision-making processes, the following criteria should be used to develop an effective local siting process. Such criteria developed through evaluation of state siting status and through interviews with both state facility siting staff, developer, and local officials could then be used to develop a "model" local process.

The following criteria are offered as benchmarks by which to judge the quality of a local siting process:

- Clearness and objectivity. The process should be understandable and impartial for all participants.

- Predictable procedure and timely results. Uncertainty and delays create costs for everyone, and can prevent needed action when logically required.

- Satisfactory protection of the affected environment. Short and long-term public support will require that facilities are environmentally-sound.

- Practical and cost-effective for participants. Neither the developer, local government, nor public benefits from cumbersome, expensive decision-making.

- Public confidence in the results. Citizen acceptance of siting decisions is an important cornerstone for satisfactory facility operations and fundamental for support of future facilities

- Legally defensible and politically feasible results. Ultimately, decisions must be sustainable by judges and voters in order to build long-term siting credibility.

Applying these criteria suggests that a "model" local siting process should include, at a minimum, the following components:

- Advance notice to communities from facility developers using "notice of intent" procedures common at state levels. This would enable communities to make appropriate workload and staffing adjustments, and to initiate the following pre-application measures.

- Public information and outreach measures that include, at a minimum: an accessible local presence by the facility developer; periodic publication and distribution of project status reports; non-formal types of "open house" information; and tours of comparable sited facilities.

- Formal, short-term training on energy technologies, impacts, mitigations strategies, and facility siting techniques for local staff and elected officials who will be acting on siting proposals. This should occur as soon after "notice of intent" filing as practical.

- Pre-application siting "charettes" among the developer, local officials, and interested persons to solicit and incorporate citizen and agency advice on the proposed facility's design and siting *prior* to project finalization and formal application submittal.

- For particularly significant facilities, creation of an advisory committee to the local planning commission and/or governing body that can: 1) serve as an additional public involvement mechanism; 2) conduct in-depth examinations of issues beyond the time available to planning commission or governing body members; and 3) provide public involvement continuity from the outset of the pre-application process, through project review and decision, and, if approved, onto advisory monitoring of facility operations.

- Conflict resolution procedures that use nonpunitive bargaining or negotiated development strategies to resolve disagreements among opposing parties outside of normal contested land-use proceedings, e.g., mediation.

- Reasonable time limits on all components of the process, so that developers and citizens alike have assurance that decisions will be reached in a timely manner.

In addition to the process leading up to a local siting decision, consideration should also be given to special appeals procedures that might be used when local decisions are challenged in court. At present, such challenges are channeled into the general court system. An alternative might be similar to the Oregon land-use approach, whereby local land-use decisions can be appealed directly to a special state land-use administrative court or alternatively siting decisions can be appealed directly to the State Supreme Court. Having an expedited appeals option such as this may be a useful counterbalance to the extra local effort implied in the foregoing model process description.

Closing

The section concludes with the following findings and recommendations:

- Local governments have been, and continue to be, significantly involved in siting both small and large energy facilities. Given a majority of localities with little or no siting expertise, the result is clearly a potential impediment to achieving a portion of state, regional, and national power goals.

- Siting standards per se are not the highest priority need for improving local capabilities. Instead, strengthening local *processes* should be a higher priority method of building public acceptance of energy facilities generally.

- Cities and counties have substantial needs for information on modern generation and transmission technologies, typical facility impacts, and recommended mitigation techniques. There are equally substantial needs for two kinds of specialized expertise: public process facilitation/negotiation; and technical (environmental, scientific, engineering) evaluation of specific facility proposals

- The provision of technical assistance should be considered as a means to overcoming many of the problems faced by local governments in siting energy projects.

- Technical assistance should be structured and provided according to the following four types of needs:
  - Establish stronger connections among the people involved. Create a stronger network among power planners and community planners.
  - Deliver/exchange information along connected lines. Use the stronger professional network to build a common knowledge base and recognition of shared interests among connected parties.
  - Deliver policy-making assistance. Explain to localities their relationship with, and benefits from, the power system; and encourage and assist in preparing local energy plans that are consistent with state, regional, and national power goals.
  - Deliver project-specific technical assistance. Provide localities with short-term process facilitation and technical analytical services for proposals that exceed local capabilities.

Specific implementation measures that should be considered in planning technical assistance programs include:

- Connecting Key Constituencies
  Publish and distribute a directory(s) of key siting entities: power planners, community planners, environmental agencies, and interest groups. Most state planning associations have a directory of local planners, but nothing exists that cuts across the issue and jurisdictional levels affected by siting.

- Establish an association of siting professionals and interested persons.

- Delivering Technical and Public Information

Establish an electronic bulletin board or clearinghouse for siting issues. The opportunity for a county planner in Maine to get help from a counterpart in Oregon working on the same kind of project will help build the common knowledge base and shared interests described earlier.

- Organize and conduct tours of successfully-sited facilities, emphasizing successful examples of project integration with surroundings and environmental mitigation. These could be organized for both technical and lay public audiences. Case studies of exemplary facilities should be developed and then showcased in literature or video materials developed.

- Develop and hold training courses or workshops for local staff and elected officials. These could be brief (one, two-day) classes held periodically that address: 1) generation and transmission technologies, impacts, and mitigations; 2) siting laws and technical standards used by permitting agencies; 3) public involvement techniques for reducing contentiousness and increasing collaboration during siting processes; and conflict resolution training, e.g., mediation.

- Delivering Local Policy-Making Assistance
  Reinforce local recognition and support for the power system by assisting in the preparation of local energy plans that are consistent with energy and environmental goals. Such planning creates a well-informed foundation on which to make future siting decisions.

- Seek out and conduct local "partnership" projects. There are many opportunities for using state or regional technical resources to address a local planning need that coincides with state regional or even national objectives. For example, state or regional geographic information systems could be used to compile locally-needed natural resource and environmental data while simultaneously conducting transmission corridor analyses. In exchange, local staff could provide needed community information to state or regional transmission planners. "Partnerships" such as this offer reinforcement of the "shared interest" strategy that could run throughout the technical assistance effort.

- Delivering Site-Specific Project Assistance
  Provide short-term process facilitation/negotiation assistance for projects that are particularly controversial. Professional facilitation can substantially reduce the adversarial nature of a process, and importantly, its ultimate length and cost.

- Provide short-term technical analytical services for complex projects. An interdisciplinary team of environmental, scientific, and engineering specialists could provide a range of facility evaluations from comprehensive project analyses down to limited examinations of specific issues. To overcome local resistance to outside influences, and to increase overall objectivity, this type of assistance should be provided by an entity that is independent of traditional state or regional permitting agencies, as is done in Maryland.

- Provide short-term additional local staffing capabilities. When justified, localities should be able to hire their own temporary staff as an alternative or in addition to the two foregoing options.

- Project-specific financial assistance for local government implementation could be made available by states and should be negotiated on a case-by-case basis according to such factors as proposed energy facility size and technology, local staff resources, and extent of project developer cost sharing via application fees. In certain instances, it may be necessary for the state legislature to authorize local communities to impose reasonable application fees to cover staff and needed consulting services.

Implementation of these measures would not only be relatively inexpensive, but would also certainly reduce the current costs of protracted, adversarial processes that are being experienced and that can be expected to continue unless local governments are better prepared to deal with energy facility siting.

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Legislative Issues Related to Combined Heat and Power Projects at State Facilities

The following suggests a number of legislative issues that states may want or need to address in establishing a program to facilitate the development of combined heat and power (CHP) projects at state and other public facilities. It is based partly on the experience of other states that have implemented similar programs and partly upon research that resulted in the establishment of broad enabling legislation and policies in Washington State that addressed the needs of both CHP and district energy.

The primary issues that must be addressed include:

- State policy
- Benefit sharing
- Project financing mechanisms
- Program funding and reimbursement
- Procurement, leasing, and contracting authority

State Policy

There must be a clearly-stated and understood state policy that CHP development at state and other public facilities contributes to both energy efficiency and a reduction in air emissions, and therefore should be fully considered wherever it is technically and economically viable for meeting present and future energy requirements.

For example, in California, the state found that in-state energy resources are extensive and available, that state energy costs are increasing, and that state policy is to use these resources when they:

- will reduce long-term energy costs and energy use, and
- may increase fuel independence and state revenues

Without a clearly declared policy encouraging CHP development, few institutions or facilities will take the initiative or accept the "risks" of initiating CHP projects. And even with such a policy, few will actively pursue CHP development without incentives for the host facility or institute to undertake the substantial efforts and incur the cost of evaluating and implementing cost-effective CHP without incentives.

Benefit Sharing Between Host Sites and State Government

State agencies and host sites are unlikely to spend the time and money required to evaluate and develop energy efficiency and CHP projects without sharing in the benefits they create. Entitlement to share in those benefits should be legislatively mandated to provide certainty, consistency, and predictability.

The legislation should define the types of project benefits to be shared between the site and the state; the proportion going to each; and the uses to which the respective benefit shares could be put. Implementing procedures should be developed; these might vary depending on the financing sources used.

Energy efficiency measures and CHP development at state facility sites can yield substantial benefits to the site and the state. These can include major direct financial benefits in the form of energy savings, avoided capital costs, and cash revenues from sales of electricity and thermal energy. They can also include non-financial benefits such as site improvements and additional O&M resources for the site.

These potential benefits do not come free to the host site or the state, but require significant commitments of time and money to achieve. Agency and facility staff must spend considerable time to identify and evaluate potential project opportunities. They must commit a great deal more time to actually implement viable projects once they have been identified. These tasks also entail substantial out-of-pocket expenses (for example, consultant time, computer analysis, equipment purchases, specialized legal and financial counsel, travel, communications, and related costs). Some of these costs will be incurred before viable projects are even identified, and some will be incurred to evaluate projects that turn out not to be viable at all. Other costs must be incurred during the lengthy development process characteristic of large energy projects, well before the projects begin to produce savings or revenues.

Experience confirms that host facilities are unlikely to commit the resources needed to pursue viable projects without some strong assurance that they can capture at least some of the benefits these projects yield.

The assurance that state participants can capture a portion of the benefits they create is not presently available under the laws of most states. On the contrary, institutional mechanisms currently in place affirmatively <u>discourage</u> pursuit of many energy efficiency and CHP opportunities.

Energy efficiency and CHP projects must compete for capital funding with core academic programs at state and regional universities and community colleges, with critical security requirements at state prisons, and with basic health care imperatives at state hospitals. However, the energy component of state facilities' utility operating budgets is rarely scrutinized in the budget process: facility managers understand that increases in ongoing energy costs can virtually always be funded our of increased operating budgets that tend to be viewed as supporting rather than competing with core facility functions, or as essential expenditures of a different order of magnitude than large energy equipment acquisitions.

This creates perverse incentives from an energy efficiency standpoint. Facility managers Have little incentive and much frustration in seeking capital funding for energy efficiency improvements and equipment that could yield many times the cost in the value of energy saved or generated over its lifetime. Instead, the systems encourage inefficient operations funded through increases in operating budgets. In the rare cases where energy costs are actually tracked in the budget process, managers have even less incentive to pursue efficiency since reduced costs could result in future budget reductions.

Early in its pioneering state program, California encountered a similar system of incentives discouraging the pursuit of cost-effective energy efficiency and CHP development in state facilities. The California CHP program was unable to attract the interest of the state agencies and institutions that have since made the program a success. <u>The Office of Energy Assessments</u>

(OEA) views the benefit-sharing legislation adopted in response to this situation as the single most important legislative initiative supporting the California program.

Recommended Legislation
Key elements of proposed legislation should include:

1. **"Benefits" Definition**. The statute should define the types of "benefits" to be shared. Possibilities include:

   - energy cost savings
   - cash revenues from energy sales
   - avoided capital costs
   - the value of any site improvements resulting from the projects
   - the value of additional O&M resources made available to the site through the projects.

   The last three listed may be difficult to measure. Measurement methodologies should be defined, possibly in the legislation but preferably in administrative rules implementing it.

2. **Percentage Sharing Requirement**. The statute should require that project benefits, however defined, be shared in some fixed percentage between the host site and the state. California mandates 50/50 sharing, which seems as good a formula as any and has worked well there. The formula could, of course, be altered so that the site or the state retains a higher percentage if it appears that greater incentives are needed by either participant.

3. **Uses of Shared Benefits**. The statute could define the uses to which funds retained by the site or shared with the state could be put. The main reasons to limit the use of the funds generated by energy projects are too meet the concerns of state budget managers that such funds could become unrestricted "slush" funds beyond the reach of the normal budget process, and to assure both state agency and site personnel whose support is needed that their departments will benefit directly from undertaking these programs and projects.

   a. Site Benefits. California restricted the site's use of cash benefits to ongoing and deferred maintenance, cost-effective energy improvements, and "other infrastructure improvements." Maintenance and energy improvements appeal to facilities managers who must energetically support these projects. "Other infrastructure improvements" may appeal to a broader constituency within the facility, since these may be broad enough to include such things as new university classrooms, administrative or faculty buildings, etc.

   b. State Benefits. In California, the statute mandates that the state's 50 percent benefit share be deposited in a state Energy and Resources Fund for the purpose of investing in renewable resource programs and further energy efficiency improvements at state facilities.

4. **Implementation Procedures**. The day-to-day mechanics for administering whatever benefit-sharing scheme is mandated can be established by administrative rules and need not be part of the legislation itself. However, the following briefly describes mechanisms that have succeeded elsewhere that may provide useful models.

   California treated the mechanics of benefit sharing for energy efficiency and CHP projects somewhat differently, depending on the source of project funding employed.

   a. <u>Revenue Bonded Projects</u>. The benefits produced by these projects are generally in the form of savings or avoided energy costs. The energy service company (ESC) developing a state project estimates the site's first-year savings. Finance makes a one-time reduction to the site's utility line item budget by that amount. The site then submits an informational budget change proposal (BCP) claim its 50 percent share of the savings amount by which its budget has been reduced; this, too, is a one-time request for retention of the 50 percent share in the site's base budget, to be used for the purposes specified in the authorizing legislation. Consistent with the statute, sites may request budget adjustments to any program or line item appropriate to their proposed use of the funds. When the ESC contract terminates after its specified term of years, the amount formerly budgeted for ESC payments becomes available as additional project savings. The site submits a second informational BCP to retain its share of those savings for the remaining life of the project.

   b. <u>Capital Outlay Projects</u>. Like revenue-bonded projects, the benefits from these projects show up as energy savings or avoided energy costs. The mechanics of dividing the benefits are similar to the revenue bond project mechanics just described: Finance makes a one-time permanent reduction in the site's budget based on the projected first-year savings, and the site submits a one-time BCP requesting to retain and use it 50 percent share of those savings for the purposes authorized.

   c. <u>Third-Party Financed Projects</u>. Third-party projects may produce benefits in the form of cash revenues as well as savings. Under the benefit-sharing legislation, cash revenues are to be split 50/50 between the site and the state. The site reports its net revenues each year to Finance. The site remits the state's 50 percent share of those revenues to the State Energy and Resources Fund, and deposits its own 50 percent share in a special deposit account earmarked for the purposes specified in the statute (ongoing and deferred maintenance, energy efficiency improvements, and "other infrastructure improvements").

Project Financing Mechanisms

Energy efficiency and CHP projects come in all shapes and sizes. Energy markets and regulatory environments change constantly. Increasing competition among suppliers requires the ability to respond quickly to these changes. Inflexibility and delay in project evaluation and development will cause lost savings opportunities and foregone revenues for the state, its agencies, and its facilities.

Flexibility and efficiency can be served by providing clear authority for state agencies to use a varied mix of financing options for energy efficiency and CHP projects. The state can then choose among the options for individual projects, depending on which will optimize project benefits to the state in each case.

Legislation should confirm the authority of the state through responsible state agencies to use capital budget funds for state facility energy projects; to issue revenue bonds and enter into financing contracts or other instruments secured by project savings or revenues; to use private, third-party financing wherever it can provide benefits to the state; and to enter financing arrangements with other agencies as needed.

State facility energy projects can involve a wide range of technologies from conservation measures, to diverse efficiency improvements, to an array of CHP equipment and fuels. The state should be able to size, structure, and finance projects in different ways, depending on its needs. Which combination will offer the state the most benefit will vary with the site's needs and the energy environment surrounding the project. The state should have the flexibility to structure projects to maximize its overall benefits, and to optimize benefits between the site and the state in each case.

Capital budget funding has been the usual source for large, state-owned, energy projects. It offers the advantage of providing relatively low-cost funding for projects that the state chooses to own, and it should remain an option wherever it can best serve the site's needs and the state's energy and financial interests.

However, the capital budget process is cumbersome and ill-suited for developing many kinds of energy projects in rapidly changing and increasingly competitive energy markets. Energy budget requests compete for funds with core functions that agencies and institutions often consider higher priorities. Separate budget requests and approvals are required at each stage of project planning, design, and construction, slowing down the process and increasing delays and uncertainties that can derail energy projects. On the other hand, the energy projects proposed for the state facility program will be selected because of their potential for energy and cost savings and/or revenue production, and these benefits can be used to support forms of financing outside the capital budget, including revenue bonds and various forms of third-party financing.

State-issued revenue bonds would be secured by energy project revenues. These might be revenues from state sales of conservation savings to utilities; they might also be revenues from sales of CHP power to utilities, or sales of thermal energy to users near the state's host facility.

State-issued revenue bonds could offer important advantages for some kinds of state facility projects. Since the loans they represent would be repaid by project revenues, they would leave state capital outlay and operating budgets available for competing state priorities. Projects eligible under federal tax laws could benefit from the lower cost of debt from tax-exempt borrowing. IRS limits on eligibility cold preclude tax-exempt borrowing for some projects, but even these might benefit from reduced borrowing costs resulting from large state bond issuances.

Financing contracts of various kinds offer another avenue for the state to finance and acquire energy efficiency and CHP projects at its facilities. These contracts can include financing leases, lease/purchase arrangements, conditional sales contracts, and similar mechanisms to permit the state to purchase property and equipment for payments extending over a period of time, just as private businesses routinely do. State agencies and institutions can enter into these arrangements, and the payments they require can be made out of currently appropriated funds or funds other than general state revenues without being considered indebtedness for purposes of constitutional limits on state debt. Such arrangements can provide added flexibility for the state in developing energy efficiency and CHP projects at state facilities, and their availability for these purposes should be confirmed.

Third-party financing stimulated by project revenue potentials is another important source for financing energy projects. Third-party projects would be privately developed, owned, and financed. They would typically be located at state facility sites under long-term leases with the facility, and would sell electric and/or thermal energy to the site under long-term contracts providing cost savings or revenues to the site. Depending on the type and scale of the projects, they might sell excess electricity to a utility and/or thermal output to nearby users.

Potential advantages to the state from third-party development include shifting of project costs and risks to private parties and utilizing their experience and expertise in energy project development until the state develops its own. The cost to the state of obtaining these advantages will usually be smaller shares of project benefits than the facility could realize if it were to develop, finance, and own the project itself.

The balance of advantages and costs to the state of third-party development can vary from site to site and project to project, and many change over time as the state gains experience in energy project development at its facilities. But whether or not third-party development turns out to be the best choice at any particular site, it should clearly be available to the state as one option for pursuing and financing these projects.

Recommended Legislation

Legislation should be broad enough to provide a flexible mix of financing options to support both state-built and third party-developed energy projects at state facilities. Key franchising elements of the proposed legislation include:

1. **Policy Statement**. The legislation should make explicit the state's intention to provide a flexible array of energy project financing options for use by state agencies and facilities to enable the state to maximize its benefits across a range of project types.

2. **Listing and Definition of Financing Options Authorized**. The statute should list and define basic financing options available to state agencies and institutions for energy efficiency and CHP project development at state sites. These would include but (consistent with the legislative policy statement suggested) would not be limited to:
   - Capital budget funding
   - Revenue bonding secured by project revenues from any source, including conservation and energy sales revenues from utilities and others
   - Financing contracts
   - Third-party financing provided by private CHP and independent energy developers or their financing entities, under which the entity agrees to provide electric or thermal energy, increased energy efficiency, or conservation measures

3. Specific Authorization to Issue Revenue Bonds. California law expressly authorized that state's Public Works Board to issue up to $50 million per year of revenue bonds to finance CHP and alternative energy equipment and conservation measures in public buildings, and to carry over unused authorizations to succeeding years, for a total of ten years or $500 million in energy project financing. Ceiling and sunset provisions may not be necessary in the proposed legislation, but a ceiling provision or some other legislative indication of dollar amounts might help legitimize the new program and confirm the magnitude of the state's commitment to it.

Program Funding and Reimbursement

It costs money to identify, evaluate, and implement energy efficiency and CHP projects at state and public facilities. Costs will include facility staff assigned to individual projects; consultants hired by the site to assist in project identification and development; and associated expenses such as travel to sites, lodgings, and communications.

Sources and mechanisms through which these costs might be paid include: 11) agency and institutional budgets funded through the state's ordinary budget process; 2) proceeds from energy efficiency/CHP revenue bonds proposed in the previous section of this paper; 3) reimbursements from successful third-party developers; 4) the Energy Efficiency Fund or a similar dedicated account earmarked for these purposes; 5) grants and loans from federal, state, and local agencies and institutions; 6) grants, loans, rebates, or other efficiency incentives from utilities; and 7) various combinations of these.

The legislation should confirm that participating agencies and institutions are authorized to receive and use any and all of these sources to fund the costs of identifying, evaluating, and implementing energy efficiency and CHP at state and public facilities.

Various funding sources and mechanisms, including those listed above, are potentially available for these purposes. Some (such as the state's ordinary budget process and interagency agreements) can probably be used without new legislation. Others (such as grants, loans, utility rebates and incentives, third-party reimbursements, and the Energy Efficiency Fund or its equivalent) may not previously have been used by participating agencies and institutions for these purposes, so it may help to clarify through legislation that, in addition to any other available sources, these sources may be used to fund the costs of identifying evaluating, and implementing energy efficiency and CHP programs and projects at state and public facilities.

To the extent that funds might come from non-state sources such as federal grants or loans, utility rebates or incentives, or third-party reimbursements, state agencies and institutions may need authority to accept and receive these funds as well as to spend them for the purposes stated. The latter source--reimbursements for the state's program and project development costs from third-party energy service companies and successful project developers--may also need to be authorized to ensure that the state can require this of private parties as one of the benefits to the state be mandated or negotiated on a project-by-project basis.

Recommended Legislation
Legislation enacted should expressly authorize state and public agencies to use funds from any or all of the following sources to pay any costs incurred for programs and projects to identify, evaluate, and implement energy efficiency and CHP in state and public facilities:

1. Budgets funded through the state's ordinary budget process;
2. Interagency agreements;
3. Energy efficiency revenue bond proceeds (see previous section);
4. Reimbursements required of third party energy developers and/or energy service companies providing services to state and public facilities;
5. The Energy Efficiency Fund (if one is created) or another dedicated account earmarked for these purposes;
6. Any grants, loans, or other funds available from federal, state, or local agencies for these purposes;
7. Any grants, loans, rebates, or other energy efficiency or CHP incentives available from utilities;
8. Any combination of these sources.

The legislation should also contain a statement that it is intended to supplement existing law and regulations governing the use of funds, and that nothing in it is intended to preclude the use of other funds available from any other source for the purposes stated.

Procurement, Leasing, and Contracting Authority

Energy efficiency and CHP projects are complex undertakings that can produce varied types of benefits for state agencies and institutions. Where the state chooses to pursue third-party development rather than state ownership of projects, it can optimize its benefits through flexible procurement processes that allow it to structure benefit streams to suit its needs, rather than requiring rigid acceptance of low-cost bids regardless of factors such as certainty and security of fuel supplies, potentially adverse regulatory changes, or environmental considerations. The authority to employ flexible procurement processes to achieve the state's policy objectives on third-party projects should be made clear and unambiguous to minimize problems in project implementation.

Whether third parties or the state develop these projects, the projects typically have a useful operating life of at least 15 to 20 years, and possibly much longer. The legal and contractual arrangements supporting them, including leases for equipment and real property and contracts for fuel purchases and electric and thermal sales, must extend over an equivalent period. Selling CHP electricity in future markets may also entail state participation in utility procurements and/or sales to consolidators and mandaters of electricity.

Legislation should make explicit the authority of state agencies and institutions and other public entities to use performance-based contracting and other flexible procurement strategies for third-party energy projects, and to enter into long-term leases and contracts for fuel as well as for electricity and thermal sales. The exercise of this authority would be limited to cases where it is reasonability calculated to reduce energy use and life-cycle costs for the state or other public entity undertaking the project.

Procurement. Once state and public facilities have identified promising energy efficiency and CHP opportunities, they can develop them either as publicly-owned projects or through private third parties that would develop, own, and operate the plants on state facility sites. In the latter cases, state and public agencies can benefit from the projects in a variety of ways. These include savings on purchased energy; discounts on steam, hot water, or chilled water; revenues from property leased for use by the project; revenue shares from electric and/or thermal sales; equipment upgrades; infrastructure improvements; and so on. The complexity of these projects and the benefit streams they produce distinguish them from most other projects that public agencies procure, and require more flexible procurement processes to enable public agencies to optimize their benefits and shape them to the individual facilities' needs.

Long-Term Leasing and Contracting. The development of energy efficiency and especially CHP in public facilities is a long-term undertaking. For larger CHP projects, the development period alone can easily extend over several years. Once in place, CHP plants should operated for at least 15 to 20 years, and often much longer. This means that the legal and contractual arrangements needed to put these projects in place must also be able to extend over the life of the project, and cannot be limited by the legislative biennium as might otherwise be the case. depending on the type of project, such arrangements can include:

1. **Ground leases of real property** by the state or public entity to a third-party developer/owner of a CHP plant located at the state or public facility;
2. **Contracts for state purchases of electricity and thermal outputs** from third party-owned CHP plants for use at the host facility;
3. **Performance-based or shared savings contracts** between state facilities and energy service companies or third-party CHP developers who provide site benefits in the form of savings;
4. **Contracts to purchase fuels** such as coal, natural gas, or biomass to run state or publicly-owned CHP plants;
5. **Contracts to sell electricity** produced by state or publicly-owned CHP plants to utilities, other state or public facilities, and possibly others; and
6. **Contracts to sell steam, hot water, or chilled water** produced by state or publicly-owned plants to other users located near the host facility site.

Some states have adopted legislation conferring on state agencies the long-term leasing and contracting authority for energy efficiency and CHP projects. Leases may be for less than fair market value if that serves to promote conservation and alternative supply and reduce the state's long-term energy expenditures. The law also authorizes state agencies to enter into contracts for the operation of such facilities and the sale, purchase, exchange, and use of energy related to them.

Recommended Legislation

It is essential that states enact legislation confirming the authority of state agencies and institutions to employ flexible procurement processes and to enter into long-term lease and contract arrangements for energy efficiency and CHP projects at state and public facilities. Key elements of the legislation would include:

1. **"Competitive Negotiation" Procurement Authority**. The legislation would 1) permit state and public instrumentalities to issue requests for statements of qualifications and/or proposals to develop energy efficiency and CHP projects at public facilities; 2) authorize them to negotiate with and select proposers whose projects offer the greatest overall benefits to the state (rather than the "lowest cost" projects); and 3) exempt sponsoring agencies and institutions from any other state or local procurement requirements that might otherwise apply.

2. **30-Year Leasing Authority**. This would confirm the authority of state and public agencies generally to lease their property to other persons or entities for up to 30 years for purposes of developing, constructing, installing, owning, operating, and maintaining equipment and systems for energy conservation and efficiency, CHP, or alternative energy supplies. The 30-year period is intended to reflect the useful life of energy equipment and systems likely to be installed under this program. The period could be longer, but probably should not be shorter.

3. **30-Year Contracting Authority**. This would confirm the authority of state and public agencies and institutions to enter into contracts for up to 30 years for the purchase, sale, and exchange of electric and thermal energy and of any fuel or energy source necessary or convenient to the operation of conservation, energy efficiency, CHP, or alternative energy supply facilities serving state and public facilities.

4. **Reasonable Anticipation of Reduced Energy Use and Costs**. To guide state and public facilities exercising the authorities recommended above, and to anticipate any concerns that they might be misused, the legislation should provide that these authorities are to be exercised where there is a reasonable anticipation that they will reduce energy use and costs to the state or other public entity invoking them.

Outside the Fence Contracting

Introduction

One of the largest barriers to greater adoption of combined heat and power (CHP) technologies by the industrial sector and, in many cases, the institutional and building sectors, is an inability to fully utilize the thermal energy that is produced and thus reach high levels of fuel use efficiency. Often CHP or cogeneration projects barely meet the 5 percent thermal use threshold established by PURPA for classification as independent power producers. Despite the fact that many CHP projects have ample opportunity to more fully utilize the thermal energy produced through sale to adjacent industries, commercial buildings, and even distributors of thermal energy, i.e., district energy companies, few are willing to enter into outside the fence contracts due to perceived or real liability risks. For example, "Will I be forced to operate to meet my customers' thermal needs should my plant be shut down due to a strike, lock out, economic downturn in my business, or some other unforeseen circumstance?"

Outside the fence contracting, though possibly new to developers of CHP in the U.S., is not unique to the U.S., and some guidance in how contractual issues have been addressed in countries where CHP, and especially district energy, is much more common, can hopefully provide some insight and guidance in how CHP developers can potentially deal with these issues here at home.

Sweden, for example, has long been a leader in the development of district energy technologies and district energy systems. As early as 1972, the Swedish District Heating Association, the National Industrial Board, the Federation of Swedish Municipalities, and the Federation of Swedish Industries developed contractual language that was meant to identify and serve as guidance to issues that should be addressed in a contract between suppliers of thermal energy and customers/distributors of thermal energy. In 1997, a new draft was developed by a working group consisting of representatives of Mariestads Energi AB, Hallstahammar Energi AB, the Swedish District Heating Association, Falbygdens Energi AB, and Umeå Energy AB. Legal council was provided by Stockholm Energi AB.

Both above mentioned drafts are provided here as a starting point for the development of contractual language that meets the needs of both sellers and purchasers of thermal energy here in the U.S. The language is not intended to serve as a "model" where only the blanks need to be filled in, but rather a listing of the issues that must be successfully negotiated by legal council and included in any agreement entered into.

Although contracts are necessary in order to establish rights and responsibilities of the parties, as well as assignments of liability, throughout Europe and Scandinavia, where distribution of thermal energy from CHP or waste heat from industry is increasingly common place, safeguards against disruption in supply are generally covered through the use of back-up boilers and chillers and, of course, equipment insurance to cover emergencies.

This section concludes with guidance on how a contract between a distributor of thermal energy and a district energy customer could possibly be structured. Once again, this is a translation of a model contract from Sweden (Uniform Regulations for the Delivery of District Heating), developed by the Swedish District Heating Association. It is not meant to serve as a model that can or should be adopted here in the U.S without thorough review by legal council.

Model Contract
For Purchase of Waste Heat or Primary Heat
For District Heating Distribution

1. Parties

This agreement is between

The Supplier
Company Name
Address
Contact Person

The Customer
Company Name
Address
Contact Person

2. Background

This agreement between ___________ (Supplier) and _________________ (Customer) has been entered into for the following purpose:

This section should include a short description of the reasons for and the circumstances surrounding the agreement. This section may also include a short history of the partners individual or common goals, etc.

3. Purpose

(Primary Heat)

The purpose of the agreement is for the Supplier to build a facility for the delivery of thermal energy (hot water or steam) to the Customer's district heating network.

(Waste Heat)

The purpose of the agreement is for the parties to cooperate in the use of available industrial waste heat for their mutual economic benefit and the good of the environment.

With existing facilities, the purpose of the agreement should reflect that situation.

4. Facilities

(Primary Heat)

The Supplier pledges to finance and build all facilities necessary for the production of energy and be responsible for the facility(s) being built in accordance with all relevant local, state, and federal regulations. The facility(s) is identified on the accompanying schematic.

A capacity requirement should be specified here and reference made to schematics and/or map(s) specifying the various facilities. If the Customer's facilities are included in the project, these should also be specified in the document.

With supply from an existing facility, it should be specified which plant(s) the Supplier pledges to maintain and that the Supplier be responsible for and insure that the facility(s) be brought in-line with all local, state, and federal regulations.

(Waste Heat)
The Supplier's facilities may include boilers, heat recovery steam generation equipment, pumps, transmission and/or distribution pipes to the Customer's heat exchanger. Specific Supplier facilities are identified on the accompanying map.

The Customer's facilities may include heat exchanger(s), transmission and distribution pipes connecting to the Supplier's facility, peaking and back-up boilers, and pumps for district heat circulation and distribution. Specific Customer facilities are identified on the accompanying map.

In the narrative, the relative facilities can be described and both the Supplier's and Customer's facilities accounted for through the use of maps and/or schematics. Responsibility for the operation and maintenance of the individual facility can be detailed. Detail concerning how future facilities that are built during the period of the agreement shall be treated should be specified.

5. Investments

If the parties contemplate future investment in waste heat or other facilities during the period of the agreement, the parties shall consult on both the technical specifications and economic characteristics of the investment, and shall seek agreement on the allocation of investment responsibility.

As an alternative, the agreement can specify that the Supplier shall be responsible for any and all investments upstream of the delivery point and the Customer for all needed investments past the point of delivery.

6. Delivery Point

If several points of delivery exist in the same system, each shall be described and identified on the schematics or maps.

7. Delivery

(Primary Heat)
The Supplier pledges to deliver all the energy that (Customer buys) is used yearly by the Customer's district energy network up to a capacity limit of X MW.

Delivery shall be made year round, and shall be based principally upon the energy estimate (Attachment 1) and temperature program (Attachment 2).

If the actual energy delivered significantly exceeds or fails to meet the quantity specified as the basis for the agreement, the parties shall enter into new negotiations. If the Supplier does not meet his/her obligations in accordance with the agreement, the Customer has the right to produce or obtain energy to meet the needs of the district energy system in another manner.
Prerequisite for renegotiation can be more precisely be stated through specifying the limits for deviation from the agreed upon delivery, i.e., ± 20 percent.

The delivery point shall be defined as the control (shut off) valve between the Supplier's and Customer's systems, and shall to be identified on the accompanying schematics or maps and described in detail.

(Waste Heat)
All thermal energy that is generated in the Supplier's facility(s) during the period of the agreement and that the Customer can sell, shall be distributed by the Customer.

For clarification of the Supplier facility(s) relative to effect and energy, a flow diagram can be attached to the agreement as an appendix.

8. Quality

(Primary Heat)

Capacity/Energy

Contracted heat capacity	X MW
Estimated heating supply	X MW/year

Pressure/Temperature

Supply shall be within the following levels, with a maximum temperature level in the supply piping proportional to the outside temperature (ºC) (ºF).

Temperature	Max. X ºC (ºF)	Min. Y ºC (ºF)
Pressure	Max. X bar	Min. Y bar

The quality of the water in the district heating network shall be equivalent to normal industry standards.

(Waste Heat)
The waste heat (day/week) average temperature and flow from the Supplier shall equal or exceed XºC(ºF) and Y m^3/day (gpm).

The quality of the waste heat from the Supplier with regard to chemical and physical characteristics, shall be equal to or exceed that specified in the agreement at the point of delivery.

If the waste heat supply temperature, flow, and/or quality does not meet the specified values, both parties shall be responsible for developing a constructive solution to re-establishment and maintenance of quality.

Consideration can be given to establishment of the Customer's right to interrupt service should the quality of the waste heat fail to meet the criteria specified in the agreement.

9. Inspection/Confidentiality

Inspection: Each party shall have the right to inspect the other's facilities and to upon reasonable notice, obtain performance data at any time.

Changes or renovation to either party's facilities that are reasonably likely to affect performance under this agreement, shall be undertaken only after consultation with the other party.

Confidentiality: Both parties agree to retain in confidence and not to disseminate information on the contents of this agreement.

Nothing in this agreement shall supersede any law requiring public disclosure.

10. Interruption in Service

The Supplier retains the right to interrupt service if necessary to avoid substantial risk to life or property. Other interruptions shall be scheduled only after consultation between the parties to minimize interference with Customer operations. Reasonable notice shall be given to the Customer so that the Customer can notify its district heating customers of any possible interruption.

In the event of failure in the heat production facility that may cause interruption of service, the Supplier shall promptly determine the reason for the failure and immediately inform the Customer of the problem and when it will be corrected.

11. Transfer of Ownership

(Primary Heat)

Prior to the Supplier transferring property, business, etc., the Supplier shall open negotiations with the Customer on the possibility of taking over the business and, if that is not possible, the granting of a right to the Customer to use the facility.

A transfer of the right to use the facility, if the Customer does not allow otherwise, shall provide for the remaining contract term, as specified in paragraph 21 of this agreement.

In the case that the Supplier transfers ownership of the facility with a right to use by the Customer, the new owner must give written notice recognizing that right.

(Waste Heat)

With the transfer of operations of the Supplier's facility(s), the Supplier shall ensure that the new owner takes over the supply of heat to the Customer according to this agreement.

12. Closure

Should the supplier make the decision to cease operation or for some other reason is forced to do so, the Supplier shall immediately advise the Customer thereof. The parties shall negotiate on the timing and form of the (termination) of the collaboration that is regulated by this agreement. Termination shall be done in such a way so as to cause minimum possible damage to both parties.

If the situation is such that the Supplier cannot operate the heat production facility(s), the Customer shall be given the possibility to negotiate taking over or leasing the Supplier's existing production facility(s).

13. Metering

Metering of the heat supplied shall take place with the help of metering equipment acceptable to both parties. The meter(s) shall be installed at the delivery point or in as close proximity as possible.

The metering equipment shall be paid for, installed, and maintained by the Supplier.

If the Customer has reason to suspect that there is an error in the metering equipment, the Customer shall immediately inform the Supplier. The Customer has the right to require testing of the metering equipment. Testing shall be carried out by the Supplier. The Customer, however, has the right to require that the testing be conducted by a neutral expert.

With testing, the meter shall be considered to be acceptable if the variation from the correct value is not greater than $\pm$5 percent with a load equal to that which prevailed during the time that the error was suspected. If the variation is greater than $\pm$5 percent, the metered value shall be corrected and energy delivered considered to equal the corrected value.

Revised invoicing or crediting shall be according to the corrected value from the time of the request for testing and a maximum of two months retroactive.

If the test is carried out at the Customer's request, and if the meter is found to be correct, the Customer shall reimburse the Supplier for those costs directly borne by the Supplier to carry out the testing. If the meter is found to be incorrect, the cost shall be borne by the Supplier. The Supplier shall inform the Customer who requested the testing, the calculated cost for the testing.

If due to technical or other causes the meter fails during any given period, the parties, will jointly calculate the amount of delivered heat based on fuel use minus the value of losses in the transmission piping during that period based on use in the district heating central plant.

Disputes relative to metering shall be referred to a neutral person or authority that both parties jointly select. Any cost incurred due to such dispute shall be paid equally by the parties.

14. Fees and Payments

(Primary Heat)

Meter reading that shall be the grounds for charges, shall be carried out once per month by the Supplier, and shall, as far as possible, carefully coincide with the Customer's meter reading in the Customer's central station.

For delivered heat, the Customer will pay the Supplier fees based upon the following:

A. **Yearly Fixed Fee**
The annual fixed payment is intended to cover the Supplier's fixed costs for personnel, operation and maintenance, repairs, insurance, cost of capital, etc.

B. **Energy Cost**
The energy payment shall cover the cost of production, including fuel, electricity, and any other costs that the parties see as variable.

Billing shall be monthly in arrears, with 1/12 of the fixed payment and with the energy payment based on metering as per paragraph 13.

Payment shall be made within 30 days from the date of the invoice. Outstanding sums shall incur an interest penalty on arrears of XX percent over the prime rate.

The fees shall be indexed to an index agreed upon by the parties. With indexing of the fixed portion of the charges, only those portions of the charge that are affected by inflation shall be included, e.g., cost of capital shall be excluded from the indexing. It would be appropriate that the variable cost be indexed to the same index, and tax that applies to the Supplier's fuel acquisition. If the Customer is responsible for back-up production, in the case of the Supplier's inability to deliver, a reduction in the fixed charge should be made if interruption in delivery exceeds, for example, 5%.

Example
The reduced fixed charge = $(C1 - (0.95 - To))$ x F
To = measured accessibility
F = Fixed charge

Payment procedure can vary from case to case, dependent upon the parties' business practices, and should be seen only as an example.

(Waste Heat)
With the delivery of energy in the form of waste heat, the Customer will pay to the Supplier fees as per the following:

A. Yearly Fixed Fee
The yearly fixed fee is designed to cover the Supplier's fixed costs relative to making waste heat available to the other party, e.g., repayment of debt based on capitol expenditures and operation and maintenance.

If the Supplier does not incur any fixed cost associated with the use of the waste heat, no fixed fee should be charged.

B. Energy Charge
The charge for the energy component can be calculated in two alternative ways:

1. The fee can be calculated based on the avoided cost of the fuel that would otherwise have been burned in the Customer's production plant during varying times of the year.

   After calculating the price, a discount can be negotiated that places the price of the waste heat at, for example, 60 percent of the cost of the avoided fuel.

   The price will vary over the course of the year, reflecting the differing costs of the avoided fuel.

2. A fixed fee for energy can be negotiated by the parties as reasonable compensation for the delivery of the waste heat.

With such compensation, the price should be indexed to some standard, e.g., consumer price index or fuel oil index.

In order that the index not cause unforeseen fluctuations in the price paid for waste heat, the index should be reviewed and, if necessary, revised every third year.

Invoicing shall be monthly, in arrears, and include 1/12 of the fixed fee as well as the energy payment for delivered energy based on metering as per paragraph 13.

Payment shall be made 30 days from the date of the invoice. Outstanding sums or portions thereof will incur an interest penalty of XX percent over the prime rate.

Because waste heat most often comes from industrial processes, it can be of advantage if the investment necessary for its use is divided between the parties.

The purpose of this is to distribute risk in case of a cessation in the delivery of waste heat as, for example, with the closing of the industrial facility. If the parties share in the investment cost, it naturally follows that some form of profit sharing should also be adopted. The basis for the calculation of relative profit share should be partly to compensate use of the waste heat and partly the party's relative investment in the project.

15. Operation/Management/Maintenance

Each of the parties shall be responsible for the cost of operation, maintenance, and renovation of their respective facilities so as to maintain a high standard. Each party is responsible for any costs associated with providing back-up for operation of its own activities.

The parties shall confer on questions relative to operation, and planned interruption in operation shall be reported well in advance. (A definite requirement for notification could eventually be set.) Any interruption in ability to deliver or receive waste heat shall be immediately reported to the other party and cause of such interruption shall be rectified as quickly as possible.

The parties shall, during the course of regularly scheduled meetings, confer on operational questions.

Each party shall be provided reasonable access to the other party's facilities relative to activities required by the agreement.

Each party shall be responsible for ensuring that their facilities meet governmental regulations relative to performance, supervision, operation, and control.

16. Force Majeure
If either party cannot carry out their obligations in accordance with the agreement due to incidents or circumstances that could not be foreseen, or are outside the party's control, they shall not be considered to be in breach of the agreement.

The party wishing to invoke force majeure shall immediately inform the other party of their intention.

17. Renegotiation
If, under the period of the agreement, critical changes occur so that conditions of the agreement can no longer be met, the parties shall engage in renegotiation with the aim of adapting the agreement to the new circumstances.

18. Transfer
This agreement may not be transferred to a third party without the other party's written permission.

Conditions for the transfer of the agreement may be specified in detail in the agreement.

Also, compare with wording in paragraph 11.

19. Dispute
Disputes relative to this agreement shall be decided by an Officer of the Courts. Any dispute concerning a question of fact arising under this contract that is not disposed of by agreement shall be decided by the Officer, who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the parties. The decision of the Officer shall be final and conclusive unless, within 30 days from the date of receipt of such copy, the party mails or otherwise submits a written appeal to the other party. All appeals shall be subject to judicial review if provided by law.

With regard to technical disputes, arbitration may be considered. Arbitration is not, however, public.

20. Damages and Cancellation

The party that causes interruption, curtailment, disturbance, or other disruption in heat delivery that causes injury to the other party shall compensate such loses.

The damaged party, in order to meet their obligation according to agreements with third parties, over and above what is stated above, has the right, after reasonable notice, to cancel the agreement and be awarded compensation for damages as a consequence of the termination of the agreement.

The level of compensation for damages can, for example, be specified as the highest X of the basic amount in accordance with laws on insurance at the time of the termination of the agreement.

21. Term of the Agreement

(Primary Heat)

This agreement shall be in effect until the day/month/year with a notice of termination of X months/years. If the agreement is not terminated, it shall be extended for Y years. Termination shall be by written notice.

The intention of an agreement for the delivery of primary heat is that such agreement be long-term. The Supplier shall give full and detailed consideration to how, for example, depreciation and cost of capital shall influence the price for the delivered energy.

So that international factors, that could not be envisioned at the time that the agreement is entered into, not have a negative impact on either party, milestones for review of the agreement should be set at appropriate intervals.

If the Supplier gives notice of terminating the agreement at the expiration of the agreement, the Customer has the right to assume control/operation of the facility. The contract for sale shall reflect the calculated remaining value of the facility.

The total of the verified cost of construction reduced, if necessary, and with an allowance for any remaining balance, minus 1/20th for each year the agreement was in force constitutes the remaining fair value of the facility.

In the case of an existing facility, any eventual assumption of control/operation can be an issue addressed in negotiation leading to adoption of the agreement.

If a transfer of the facility is not possible, and if the Customer so wishes, the Supplier can make the facility available for use by the Customer for the remaining useful life or for a shorter period to which the parties agree.

If the Customer terminates the agreement prior to the expiration of the agreement and the Supplier, therefore, is left without the possibility of marketing the heat that can be produced by the facility, the Customer shall compensate the Supplier in an amount equal to the calculated remaining value of the facility.

(Waste Heat)

This agreement shall remain in effect until the day/month/year, and shall be automatically extended by Y years unless written notice to terminate is provided by either party XX months/years prior to the termination date.

The intention of the waste heat agreement is that it be as long term as possible. In order that external factors that could not be foreseen at the time of the agreement's signing shall not have a negative impact on either party, milestones for review of the agreement should be set at appropriate intervals.

The requirement for written notice of termination should be set considerably longer than would normally be required so that the parties may have ample time to make other arrangements should the agreement be allowed to expire on the termination date.

22. Insurance

It shall be the duty of each party to carry insurance to cover their respective economic interest, including liability against third-party suits.

Service disruption insurance for disruptions of service due to damage caused by fire, break in, water, machine failure, and comprehensive should be carried since traditional service disruption insurance carried by the Customer will normally cover only the disruptions to the Customer's own facilities.

Template for Contract Between Waste Heat Supplier and District Heating Distributor

23. Parties

This agreement is between

The Supplier
Company Name
Address
Contact Person

The Customer
Company Name
Address
Contact Person

24. Background

This agreement between ___________ (Supplier) and ________________ (Customer) has been entered into for the following purpose:

This section should include a short description of the reason for and the circumstances surrounding the agreement. This section may also include a short history of the partners individual or common goals, etc.

25. Purpose

Waste Heat

The purpose of the agreement is for the parties to cooperate in the use of available industrial waste heat for their mutual economic benefit and the good of the environment.

26. Facilities

Waste Heat

The Supplier's facilities may include boilers, heat recovery steam generation equipment, pumps, transmission and/or distribution pipes to the Customer's heat exchanger. Specific Supplier facilities are identified on the accompanying map.

The Customer's facilities may include heat exchanger(s), transmission and distribution pipes connecting to the Supplier's facility, peaking and back-up boilers, and pumps for district heat circulation and distribution. Specific Customer facilities are identified on the accompanying map.

In the narrative, the relative facilities can be described and both the Supplier's and Customer's facilities accounted for through the use of maps and schematics. Responsibility for the operation and maintenance of the individual facility can be detailed. Detail concerning how future facilities that are built during the period of the agreement shall be treated should be specified.

Primary Heat

The Supplier pledges to finance and build all facilities necessary for the production of energy and be responsible for the facility(s) being built in accordance with all relevant local, state, and federal regulations. The facility(s) is identified on the accompanying map.

A capacity requirement should be specified here and reference made to drawings and/or map and the various facilities specified. If the Customer's facilities are included in the project, these should also be specified in the document.

With supply for an existing facility, it should be specified which plant(s) the Supplier pledges to maintain and that the Supplier be responsible for and insure that the facilities be brought in-line with all local, state, and federal regulations.

27. Investments

If the parties contemplate future investment in waste heat or other facilities during the period of the agreement, the parties shall consult on both the technical and economic characteristics of the investment, and shall seek agreement on the allocation of investment responsibility.

As an alternative, the agreement can specify that the supplier shall be responsible for any and all investments upstream of the delivery point and the Customer for all needed investments past the point of delivery.

28. Delivery Point

The delivery point shall be defined as the control (shut off) valve between the Supplier's and Customer's systems, and shall to be identified on the accompanying map and described in detail.

If several points of delivery exist in the same system, each shall be described and identified on the map.

29. Delivery

All thermal energy that is generated in the Supplier's facility during the period of the agreement and that the Customer can sell, shall be distributed by the Customer.

For clarification of the Supplier facility relative to (effect) and energy, a flow diagram can be attached to the agreement as an appendix.

Primary Heat

The Supplier pledges to deliver all the energy that (Customer buys) is used yearly by the Customer's district energy network up to a capacity limit of ____ MW.

Delivery should be made year round, and should be based principally upon the energy (Appendix 2) estimate (Appendix 1) and temperatures proven.

If the actual energy delivered significantly exceeds or falls below the quantity specified as the basis for the agreement, the parties shall enter into new negotiations. If the Supplier does not meet his/her obligations in accordance with the agreement, the Customer has the right to produce or obtain energy to meet the needs of the district energy system in another manner.

Prerequisite for renegotiation can more precisely be stated through specifying the limits for deviation from the agreed upon delivery, i.e., ± 20 percent.

30. Quality

The waste heat (day/week) average temperature and flow from the Supplier shall equal or exceed XºC(F) and Y m^3 (gpm)/day.

The quality of the waste heat from the Supplier with regard to chemical and physical characteristics, shall be equal to or exceed the conditions of the agreement at the point of delivery.

If the waste heat supply temperature, flow, and/or quality does not meet the above values, both parties shall be responsible for developing a constructive solution to re-establish and maintain quality.

Consideration can be given to establishment of the Customer's right to interrupt service should the quality of the waste heat fail to meet the criteria specified in the agreement.

Primary Heat

<u>Capacity/Energy</u>

Contracted heat capacity	X MW
Estimated heating supply	X MW/year

<u>Pressure/Temperature</u>

Supply should be within the following levels, with a maximum temperature level in the supply piping ________________ with a proportional outside temperature (ºC) (ºF).

Temperature	Max. X ºC (ºF)	Min. Y ºC (ºF)
Pressure	Max. X bar	Min. Y bar

The quality of the water in the district heating network shall be equivalent to normal industry standards.

31. Inspection/Secrecy

Inspection: Each party shall have the right to inspect the other's facilities and to obtain performance data at any time, upon reasonable notice.

Changes or renovation to either party's facilities that are reasonably likely to affect performance under this agreement, shall be undertaken in consultation with the other party.

Secrecy: Both parties agree to retain in confidence and not to disseminate information on the contents of this agreement.

Nothing in this agreement shall supersede any law requiring public disclosure.

32. Interruption in Service

The Supplier retains the right to interrupt service if necessary to avoid substantial risk to person or property. Other interruptions shall be scheduled after consultation between the parties to minimize interference with Customer operations. Reasonable notice shall be given to the Customer so that Customer can notify its district heating customers of a possible interruption.

In the event of failure in the heat production facility that may cause interruption of service, the Supplier shall promptly determine the reason for the failure and immediately inform the Customer of the problem and when it will be corrected.

33. Transfer of Ownership

(Waste heat)
With the transfer of operations of the Supplier's facility, the Supplier shall ensure that the new owner takes over the supply of heat to the Customer according to this agreement.

Prior to the Supplier transferring property, business, etc., the Supplier shall open negotiations with the Customer on the possibility of taking over the business and, if that is not possible, the granting of a right to the Customer to use the facility.

A transfer of the right to use the facility, if the Customer does not allow otherwise, shall provide for the remaining contract term, as specified in paragraph 21 of this agreement.

In the case that the Supplier transfers ownership of the facility with a right to use by the Customer, the new owner must give notice recognizing that right.

34. Closure

Should the supplier make the decision to cease operation or for some other reason is forced to do so, the Supplier shall immediately advise the Customer thereof. The parties shall negotiate on the timing and form of the (termination) of the collaboration that is regulated by this agreement. Termination shall be done in such a way so as to cause minimum possible damage to both parties.

If the situation is such that the Supplier cannot operate the heat production facility, the Customer shall be given the possibility to negotiate taking over or leasing the Supplier's existing production facilities.

35. Metering

Metering of the heat supplied shall take place with the help of metering equipment acceptable to both parties. The meter shall be installed at the delivery point or in as close proximity as possible.

The metering equipment shall be paid for, installed, and maintained by the Supplier.

If the Customer has reason to suspect that there is an error in the metering installation, The Customer shall immediately inform the Supplier. The Customer has the right to require testing of the metering installation. Testing shall be carried out by the Supplier. The Customer, however, has the right to require that the testing be conducted by a neutral expert.

With testing, the meter shall be considered to be acceptable if the variation from the correct value is not greater than ± 5 percent with a load equal to that which prevailed during the time that the error was suspected. If the variation is greater than ± 5 percent, the metered value shall be corrected and energy delivered considered to equal the corrected value.

Revised invoicing or crediting shall be according to the corrected value from the time of the request for testing and a maximum of two months retroactive.

If the test is carried out at the Customer's request, and if the meter is found to be correct, the Customer shall reimburse the Supplier for those costs directly borne by the Supplier to carry out the testing. If the meter is found to be incorrect, the cost shall be borne by the Supplier. The Supplier shall inform the Customer that requested the testing of the calculated cost for the testing.

If due to technical or other causes the meter fails during any given period, the parties, will jointly calculate the amount of delivered heat based on fuel use minus the value of losses in the transmission piping during that period based on use in the district heating central plant.

Disputes relative to metering shall be referred to a neutral person or authority that both parties jointly select. Any cost incurred due to such dispute shall be paid equally by the parties.

36. Fees and Payments
With the delivery of energy in the form of waste heat, the Customer will pay to the Supplier fees as per the following:

C. A Yearly Fixed Fee
The yearly fixed fee is designed to cover the Supplier's fixed costs relative to making waste heat available to the other party, e.g., repayment of debt based on capitol expenditures and operation and maintenance.

If the Supplier does not incur any fixed cost associated with the use of the waste heat, no fixed fee should be charged.

D. Energy Charge
The charge for the energy component can be calculated in two alternative ways:

3. The fee can be calculated based on the avoided cost of the fuel that would otherwise be burned in the Customer's production plant during varying times of the year.

   After calculating the price, a discount can be negotiated that places the price of the waste heat at, for example, 60 percent of the cost of the avoided fuel.

   The price will vary over the course of the year, reflecting the differing costs of the avoided fuel.

4. A fixed fee for energy can be negotiated by the parties as reasonable compensation for the delivery of the waste heat.

With such compensation, the price should be indexed to some standard, e.g., consumer price index or fuel oil index.

In order that the index not cause unforeseen fluctuations in the price paid for waste heat, the index should be reviewed every third year.

Invoicing shall be monthly, subsequent to use, and include 1/12 of the fixed fee as well as the fee for delivered energy based on metering as per paragraph 13.

Payment shall be due 30 days from receipt of the invoice. Unpaid invoices or portions thereof will incur an interest penalty of XX percent over the prime rate.

Because waste heat most often comes from industrial processes, it can be of advantage if the investment necessary for its use is divided between the parties.

The purpose of this is to distribute risk in case of a cessation in the delivery of waste heat as, for example, with the closing of the industrial facility. If the parties share in the investment cost, it naturally follows that some form of profit sharing should also be adopted. The basis for the calculation of relative profit share should be partly to compensate use of the waste heat and partly the party's relative investment in the project.

Primary Heat

Meter reading that shall be the grounds for charges, shall be carried out once per month by the Supplier, and shall, as far as possible, carefully coincide with the Customer's meter reading in the Customer's central station.

For delivered heat:

The Customer will pay the Supplier for delivered energy based upon the following:

C. **Annual Payment**

The annual fixed payment is intended to cover the Supplier's fixed costs for personnel, operation and maintenance, repairs, insurance, cost of capital, etc.

D. **Energy Cost**

The energy payment shall cover the cost of production, including fuel, electricity, and any other costs that the parties see as variable.

Billing shall be monthly in arrears, with 1/12 of the fixed payment and with the energy payment based on metering as per paragraph 13.

Payment shall be made within 30 days from the date of the invoice. Outstanding sums shall incur a penalty interest on arrears of X% over the effective discount rate.

The charges fees shall be indexed to an index agreed upon by the parties with indexing of the fixed portion of the charges, only those portions of the charge that are affected by inflation shall be included, e.g., cost of capital shall be excluded from the indexing.

It will be approximately that the variable cost be indexed to the same index, and tax that applies to the Supplier's fuel acquisition. If the Customer is responsible for back-up production, in the case of the Supplier's inability to deliver, a reduction in the fixed charge should be made if interruption in delivering exceeds, for example, 5%.

Example
The reduced fixed charge = C1- (0.95 - To) x F
To = measured accessibility
F = Fixed charge

Payment procedure can vary from case to case, dependent upon the parties' business practices, and should be seen only as an example.

37. Operation/Management/Maintenance

Each of the parties shall be responsible for the cost of operation, maintenance, and renovation of their respective facilities so as to maintain a high standard. Each party is responsible for any costs associated with providing back-up for operation of its own activities.

The parties shall confer on questions relative to operation, and planned interruption in operation shall be reported well in advance. (A definite requirement for notification could eventually be set.) Any interruption in ability to deliver or receive waste heat shall be immediately reported to the other party and cause of such interruption shall be rectified as quickly as possible.

The parties shall, during the course of regularly-scheduled meetings, confer on operational questions.

Each party shall be provided access to the other party's facilities relative to activities required by the agreement.

Each party shall be responsible for ensuring that their facilities meet regulations relative to performance, supervision, operation, and control.

38. Force Majeure

If either party cannot carry out their obligations in accordance with the agreement due to incidents or circumstances that could not be foreseen, or are outside the party's control, they shall not be considered to be in breach of the agreement.

The party wishing to invoke force majeure shall initially inform the other party of their intention.

39. Renegotiation

If, under the period of the agreement, critical changes occur so that conditions of the agreement can no longer be met, the parties shall engage in renegotiation with the aim of adapting the agreement to the new circumstances.

40. Transfer

This agreement may not be transferred to a third party without the other party's written permission.

Conditions for the transfer of the agreement may be specified in detail in the agreement.

Also, compare with wording in paragraph 11.

41. Dispute

Disputes relative to this agreement shall be decided by an Officer of the Courts. Any dispute concerning a question of fact arising under this contract that is not disposed of by agreement shall be decided by the Officer, who shall reduce the decision to writing and mail or otherwise furnish a copy thereof to the parties. The decision of the Officer shall be final and conclusive unless, within 30 days from the date of receipt of such copy, the party mails or otherwise submits a written appeal to the other party. All appeals shall be subject to judicial review if provided by law.

With regard to technical disputes, arbitration may be considered. Arbitration is not, however, public.

42. Damages and Cancellation

The party that causes interruption, curtailment, disturbance, or other disruption in heat delivery that causes injury to the other party shall compensate such loses.

The damaged party, in order to meet their obligation according to agreements with third parties, over and above what is stated above, has the right after reasonable notice to cancel the agreement and be awarded compensation for damage as a consequence of the termination of the agreement.

The level of compensation for damage can, for example, be specified as the highest X of the basic amount in accordance with laws on insurance at the time of the termination of the agreement.

43. Term of the Agreement
Waste Heat

This agreement shall remain in effect until the day/month/year, and shall be automatically extended by Y years unless written notice to terminate is provided by either party XX months/years prior to the termination date.

The intention of the waste heat agreement is that it be as far sighted as possible. In order that external factors that could not be known at the time of the agreement's signing shall not have a negative impact on either party, the agreement should be reviewed at suitable intervals.

The requirement for written notice of termination should be set considerably longer than would normally be required so that the parties may have ample time to make other arrangements should the agreement be allowed to expire on the termination date.

Primary Heat

This agreement shall be in effect until the ___________________ with a notice of termination of X months/years. If the agreement is not terminated, it shall be extended for Y years. Termination shall be by written notice.

The intention of an agreement for the delivery of primary heat is that such agreement be long-term. The Supplier shall give full and detailed consideration to how, for example, depreciation and cost of capital shall influence the price for the delivered energy.

So that international factors, that could not be envisioned at the time that the agreement is entered into, not have a negative impact on either party, milestones for review of the agreement should be set at appropriate intervals.

If the Supplier gives notice of terminating the agreement at the expiration of the agreement, the Customer has the right to assure control/operation of the facility. The contract for sale shall reflect the calculated remaining value of the facility.

The total of the verified cost of construction reduced, if necessary, and with an allowance for any remaining balance, minus 1/20th for each year the agreement was in force constitutes the remaining fair value of the facility.

In the case of an existing facility, any eventual assumption of control/operation can be an issue addressed in negotiation leading to adoption of the agreement.

If a transfer of the facility is not possible, and if the Customer so wishes, the Supplier can make the facility available for use by the Customer for the remaining useful life or for a shorter period to which the parties agree.

If the Customer terminates the agreement prior to the expiration of the agreement and the Supplier, therefore, is left without the possibility of marketing the heat that can be produced by the facility, the Customer shall compensate the Supplier in an amount equal to the calculated remaining value of the facility.

44. Insurance

It shall be the duty of each party to carry insurance to cover their respective economic interest, including liability against third-party suits.

Service disruption insurance for disruptions of service due to damage caused by fire, break in, water, machine failure, and comprehensive should be carried since traditional service disruption insurance carried by the Customer will normally cover only the disruptions to the Customer's own facilities.

Swedish District Heating Association
Uniform Regulations for the Delivery of District Heating

Accepted by:____
Valid from: ____

District Heating Supply

1. The Subscriber agrees to purchase district heating under the conditions prescribed in the following regulations.

   Parties to the agreement have the right to require a written contract concerning district heating service.

   The Subscriber may not deliver heat to any other building or structure nor may the Subscriber transfer rights to service under the contract agreement without the Supplier's written permission.

2. The Supplier guarantees to meet the Subscriber's maximum heat requirement as calculated.

   If the Supplier has reason to believe that the agreed upon heat requirement deviates substantially from the actual usage, he may require inspection. If, after such inspection, a deviation of $\pm$ 5 percent is found, the contract shall be changed to reflect the new value. If the inspection is made at the Subscriber's request, its cost shall be borne by the Subscriber if the agreed upon heat requirement is found to be too low. Otherwise, the inspection cost shall be the Supplier's responsibility.

3. The agreement to purchase district heating will terminate three months after written notice by the Subscriber unless another notice period has been agreed upon.

Suppliers System

4. The Supplier is responsible for, pays for, and owns the system up to the point of connection as determined by the Supplier. The system's design and location is determined by the Supplier after consultation with the subscriber. The Supplier determines requirements for pressure and temperature as well as other technical parameters.

   The Supplier is responsible for maintenance, repairs, modification, and/or removal of any equipment that is a part of the system.

   Before the Supplier begins any work related to the installation of the system, all permit approvals must be obtained from the appropriate authorities.

5. Metering equipment is provided by the Supplier. The location of the metering equipment is determined by the Supplier after consultation with the Subscriber and must provide for free access by the Supplier.

   Metering equipment remains the property of the Supplier and may only be handled by the Supplier. The cost of all metering equipment including but not limited to electrical equipment, will be borne by the Subscriber and must be provided and mounted as prescribed by the Supplier.

6. The Subscriber shall provide access to the metering system as well as other equipment provided by the Supplier. Seals on metering equipment may not be removed or tampered with without the Supplier's written permission.

   When a Subscriber intends to modify, remodel, or demolish a building to which district heating service is provided, the Subscriber shall take and pay for all necessary precautions, acceptable to the Supplier, in order to minimize damage to Supplier's equipment as well as interruption in heat distribution. In regard to the moving or modifying of the district heating pipes, see §32b.

District Heating Installation

7. District heating installation includes piping for the system as well as heat exchangers or other equipment that is in direct contact with the district heating system.

8. Subscriber may not, without written permission of the Supplier, change or modify the district heating installation. The Supplier shall determine pressure, temperature, and all other parameters as well as the technical design.

Customer Station

9. The Subscriber shall, without cost to the Supplier, be responsible for the customer station which shall contain the heat exchanger and all associated equipment. The customer station shall be kept accessible to the Supplier. A key box shall be provided and maintained by the Subscriber within the Subscriber's premises unless other acceptable arrangements have been made.

10. The customer station may not be used for any purpose that will interfere with system operation or which will impede access.

    The Subscriber shall be responsible for cleaning, lighting, and maintenance of the customer station.

Secondary System

11. The secondary system is made up of the Subscriber's heating and domestic hot water systems.

12. Installation, modification, and repairs to the secondary system shall be made according to standard practice and requirements of the Supplier.

13. The secondary system must be well maintained. The Subscriber must, upon request, provide the Supplier with information concerning the operating condition of the secondary system and the heating efficiency of the secondary system.

    The Supplier may require such modifications to the secondary system that are necessary to make it operate most efficiently.

Testing and Approval

14. The Subscriber's district heating installation may not be put into operation before it is pressure tested and approved by the Supplier. Pressure testing shall be paid for by the Subscriber.

15. The Supplier has the right to inspect the Subscriber's district heating installation and its use.

16. The Subscriber must provide the Supplier access to the secondary system for testing and inspection.

17. The Supplier's testing and approval of the installation does not imply that the Supplier is in anyway responsible for the condition of the Subscriber's district heating installation, customer station, or secondary system. Nor does it free the Subscriber or the installer of the system from responsibility and obligation for the system.

Operation

18. The Subscriber shall insure that water from the Supplier's system is not tapped without his written permission and shall pay damages for water which is tapped or leaks from the Subscriber's system due to problems with the district heating installation.

    The Subscriber shall immediately report any operational problems, leakage, or any other irregularities in operation to the Supplier.

    The Subscriber shall operate valves belonging to the Supplier only with the Supplier's written permission and then only in accordance with his directions.

Disruption of Supply

19. The Supplier shall not be liable for disruptions in supply beyond his control. The Supplier is justified in disrupting service if there is a danger of personal injury or property damage or in order to make repairs which are necessary to ensure continued service. If the Supplier anticipates the necessity for a disruption in service, he shall provide reasonable notice to the Subscriber.

20. If service must be disrupted under paragraph 19, or will be available in limited quantities, the Supplier has the right to apportion the available quantities among the Subscribers. The Supplier has the right to install equipment in the customer station to permit any such apportionment.

Metering and Billing

21. Billing shall be according to these general regulations. If applicable rates require metering of Subscriber's district heating utilization, metering as per paragraph 5 shall be the basis for such billing. If a meter in working order is temporarily unavailable or if there is good reason to suspect that the meter is incorrect, the Supplier may bill based on estimated values. If billing is based upon an estimation rather than actual metering, the Supplier must notify the Subscriber at the time of billing.

22. The Supplier has the right to bill in advance. Consumption charges shall be based upon calculated values. If the Subscriber is able to show that the calculations were based upon false assumptions, the billing shall be adjusted upon the Subscriber's request. In the case of advance billing, a closing statement shall be presented at least once per year or when subscription is terminated.

23. Meter reading for single family houses must take place a minimum of once per year and for other installations a minimum of three times per year at the discretion of the Supplier. Billing shall take place quarterly.

24. If the Subscriber has reason to believe that either the meter or the billing is in error, he shall immediately inform the Supplier. Subscriber has the right to have any suspected error investigated. Investigation shall be undertaken by the Supplier or, if requested by the Subscriber, by a recognized expert. If the parties cannot agree upon the selection of the recognized expert, either party has the right to request that an expert be selected by the local government.

    With investigation by the Supplier or expert:

    a. The billing shall be considered correct if the meter value does not vary more than $\pm$ 5 percent from the correct value through the range 20 to 100 percent of its greatest capacity. If the meter is in error by more than $\pm$ 5 percent, the billing shall be corrected.

    b. If billing can not be based upon metered values, heat utilization shall be calculated based upon Subscriber's past utilization under a similar period.

    c. If the Subscriber requests an investigation and no error is found, the Subscriber shall reimburse the Supplier for costs incurred during the investigation. If the meter or billing are found to be in error, the Supplier shall bear the cost of the investigation.

    If a district heating Subscriber is unsatisfied with the investigation as described above, the Subscriber can request assistance from the courts.

25. Any error in the meter reading or in the calculations based upon such meter reading shall be corrected.

Payment

26. The Subscriber shall pay fees according to the terms of the contract, accepted rate schedules, these regulations, and state and local law. The Subscriber is required to pay for all district heat supplied to him whether or not a portion of that heat could not be utilized by the Subscriber due to problems with his equipment or other reasons that prevented such use.

    If the Subscriber, through some error as described in paragraphs 2, 24, and 25, or because of any other reason has paid too much, he has the right to full reimbursement. If the Subscriber has paid too little, he shall be required to make up the difference. Back billing or credit shall only be honored three years from the date of the original billing.

27. The Subscriber shall pay billings on time. If a payment is not made on time, the Supplier shall have the right to charge interest in an amount prescribed by law and require reimbursement for cost incurred because of the delay in payment.

28. If the connection fee is paid over a period of years, interest shall be paid on the outstanding balance.

Disconnection and Connecting

29. If the Subscriber fails to pay the charges described in paragraphs 26-28, or if other major sums are owed to the Supplier, the Supplier may disconnect service (in accordance with applicable laws) if it will not result in a health risk. Subscriber shall be notified of pending disconnect 14 days in advance of the disconnection.

    The Supplier also has the right to refuse service to those whom the Supplier determines to be a bad risk. The Supplier's costs for disconnecting and reconnecting service shall be paid by the Subscriber.

Reimbursement for Damage

30. If either the Supplier or the Subscriber has caused the other party damage, the damaged party shall have the right to reimbursement for such damage.

Use of Property for Supplier’s Equipment

31. For purposes of installing, maintaining, and repairing the Supplier's equipment, the Subscriber shall grant the Supplier unlimited access to his property.

32. In general, both parties shall work so that the following shall be realized:

a. The Supplier has the right to install and maintain district heating pipes on the Subscriber's property for the purpose of delivering district heating. The Supplier shall reimburse the Subscriber for any direct damage caused by the Supplier to the Subscriber's property.

b. The Subscriber may not construct any structures, change the surface of the property, or store materials closer to the district heating pipes than agreed upon with the Supplier.

   If the Subscriber requests that district heating pipes be moved or in any other way modified, the Supplier shall comply if it is not technically or economically impractical to do so. All cost for moving or modifying district heating pipes at the request of the Subscriber shall be borne by the Subscriber unless such pipe is used to serve another Subscriber.

c. If the Subscriber transfers ownership of the property or building housing the Supplier's equipment, he shall make it a condition of the transfer to guarantee the rights reserved to the Supplier in points a and b above.

d. The Subscriber shall, if requested to do so, sign a service agreement covering the Supplier's equipment.

Changes and Additions

33. The Supplier retains the right to change or make additions to these uniform regulations and fee schedules. The Subscriber shall be notified in writing a minimum of three months before any changes or additions in these uniform regulations take effect.

34. The Supplier may reach agreement with the Subscriber on any and all district heating questions that are not regulated in these uniform regulations or fee schedules.

Appendix A
SELECTED LOCAL GOVERNMENT TRANSMISSION PRACTICES

Many local codes define transmission facilities as a kind of public utility and distinguish between "distribution" facilities (which are permitted everywhere, although they may have to be underground) and "transmission" facilities. Having recognized the use, they then list where that use is permitted and under what conditions. A sampling follows:

- Lancaster County, Pennsylvania, defines transmission facilities as an "essential service installation" and permits them in all districts with only a design-oriented review. Anne Arundel County, Maryland, also has defined transmission lines (i.e., >69 kV) as an "essential utility" and subjects them only to administrative review of design issues. Southfield, Michigan, allows transmission lines outright in all zones.

- Fairfax County, Virginia, defines transmission lines as a utility and classifies them as a "special exception." In some zoning districts, these lines are allowed by right. In other zoning districts, they are subject to a discretionary review process. In some zoning districts, they are prohibited. The County also recognizes the supremacy of the State Corporation Commission to permit transmission lines, and waives jurisdiction over such lines.

- Jackson, Missouri, defines "public utility" to include generating facilities and transmission lines, and allows them in all zones, subject to broad conditional use standards.

- Troy, Michigan, defines transmission lines and generating facilities as "utility and public service" uses and allows them throughout the jurisdiction, except in residential zones where they are prohibited.

A few local governments have adopted standards for siting of transmission lines:

- Before approving a transmission line, Montgomery county, Maryland, holds a public hearing to consider (1) where the line crosses major streets; (2) the proximity of the line to schools, churches, parks, and other public gathering places; (3) the potential for low-level flying in the area; (4) fire hazard; (5) uncompensated property value effects; and (6) environmental quality and ecological balance.

- Before approving a "regional utility facility," defined to include a transmission line operating at 115 kV or more and serving more than the city, Bellevue, Washington, requires an applicant to show: (1) the facility minimizes adverse impacts through location, design and construction techniques, and by restoring the property; (2) the facility uses the best available technology; (3) the facility is necessary for the effective functioning of the utility; and (4) there is no practical alternative to the proposal with fewer impacts.

- In Baltimore County, Maryland, a transmission line is identified as a "public utility" permitted only by special exception. The applicant must show that: (1) the facility is needed for the proper rendition of the public utility's service; (2) the location will not seriously impair the use of neighboring property; and (3) in a residential zone, the use must have an exterior appearance harmonious with the general character of the neighborhood, to the extent practicable. The county can require transmission lines to be installed underground after considering factors like those used by Montgomery County.

Even fewer local governments have adopted comprehensive plan elements dealing specifically with siting transmission facilities. One such jurisdiction is Albuquerque, New Mexico. Its Service Plan, first adopted as an element of the Comprehensive Plan in 1971, lists projects and standards addressing the general location, extent, and character of electrical transmission and subtransmission facilities. It was last amended in 1985. Future amendments will address other investor-owned public utilities in the city and surrounding Bernalillo County.

The Albuquerque service plan defines a variety of terms relevant to siting energy facilities, lists goals for facility siting, and contains standards for the location and design of facilities. For instance, standards promote use of existing rights of way, easement, streets, and other utility corridors over development of new corridors. New transmission corridors shall take advantage of existing topographic features and avoid ridgetops to minimize visual impact; and new corridors should minimize disruption of the natural environment and the existing land use pattern. To facilitate updating, the plan provides for amendments, a corridor planning process, and a project review process. It provides outlines for a typical siting study and sample plans, landscape standards, pole designs, and noise regulations. This plan offers one of the most complete local treatment of siting transmission facilities in the authors' experiences.

One subject about which local governments are increasingly interested is potential health effects of EMF. However, there is no scientific consensus about what level of EMF is "safe."

A few local governments have tried to regulate EMF in response to public concerns. Standards often reflect prudent avoidance, available technology and mitigation measures, and preservation or improvement of the status quo regarding EMF exposure. Also, mitigation of EMF has been proposed; design alternatives for transmission lines, voltages, phasing, and structures can significantly affect EMF exposure at the ground. Examples of EMF regulations include the following:

- The Village of Brentwood, Tennessee, attempted to impose a 4 milliGauss (mG) exposure limit on a 120 kV line being built as part of a TVA project; a court ultimately ruled the village had no jurisdiction over a federal facility. MilliGausses measure magnetic field; typical household ambient levels are less than 2 mG.

- The Village of Wilmette, Illinois, imposed as a condition of approval of a conditional use permit for a new light raid system a 2 mG standard for magnetic fields associated with a substation for the system and prohibited measurable increases in EMF measured at the property line.

- The City of Irvine, California, adopted regulations prohibiting schools and dwellings in areas exposed to 4 mG of 60 Hz EMF. That typically resulted in a need for setbacks of 180 to 300 feet between lines and such uses. Instead of regulating EMF *per se*, the California State Board of Education prohibits new schools within 100 feet of a 100-110 kV line; 150 feet of a 220-230 kV line; and 250 feet of a 345 kV line.

Appendix B
KEYSTONE MODEL FOR DEVELOPING A STATE SITING ACT

See Keystone, 1992, in References

The Keystone model is for drafting a transmission line siting law, but it applies with equal value to siting other types of energy facilities. It was the result of a year-long collaborative effort intended to provide a model state certification and siting code for intrastate electric transmission lines and facilities, and involved participants from power companies, state and local government, and other interested parties. The Project's "dialog" offers the following recommendations for agencies who do, or may, regulate transmission line certification and siting:

1. Specify reasonable time frames for deadlines for each major decision point in the regulatory process (e.g., application review, impact studies and report writing, public hearings, decision making).

2. Clarify the criteria that will be used to make the certification and siting decision so they help guide planning by clearly defining the factors that influence the decision makers.

3. Provide for early involvement of the affected landowners and the general public in the siting process, including the opportunity for public involvement in identifying alternative routes or sites.

4. Address concerns raised by all parties involved in the process, including technical and professional assessment of possible impacts.

5. Coordinate permit processing so one agency is responsible for making decisions for all permits for a project. That agency should be at the state level of government, although local governments and entities should be involved and the issues they raise should be adequately addressed.

6. Develop criteria for identifying preferred sites (e.g., existing transportation and utility corridors) and discouraged sites (e.g., environmentally sensitive areas), based on an overall evaluation of the costs and benefits of proposed and alternate routes.

7. Adopt specific need standards for the types of bulk power transactions that will warrant new transmission lines.

8. Combine need and siting issues in one process.

9. Keep abreast of research about health effects of electric and magnetic fields (EMF); help educate the public about these effects; consider the current state of research in the siting process. This issue was recognized by participants as one of the most contentious in the process.

Based on the preceding guidelines and proposals and discussions by participants, a consensus model state siting code was provided. The model code recognizes one siting agency for the state. The agency has siting authority for transmission lines with a capacity of 100 kV or more. However, certain lines are exempt from regulation, such as facilities that need to be replaced due to causes beyond the control of the operator. Also, the agency can waive compliance with the code if either: (1) there is an immediate and urgent need for the facility and the applicant did not know about that need soon enough to fully comply with the code, or (2) the facility in question is unlikely to have a significant environmental impact by reason of length, size, location, available space of right of way, or construction method. A waiver process was provided.

The agency is empowered to adopt rules to administer the code. The agency also can empanel scientific, technical, and other advisory task forces to advise it about rules. The rules of the state The agency clearly preempt or supersede other state and local laws and federal laws to the extent permitted, and another state or local agency cannot require any approval, permit, certificate or other condition for construction, operation, or maintenance of a facility authorized by the state siting agency. There also are rules regarding eminent domain, funding, coordination, and notice.

Regarding notice to the agency, the code provides that anyone contemplating construction of a transmission facility within the state shall furnish the state siting agency with a facility plan for the ensuing 10-year period and other relevant data such as power transmission requirements and a least cost plan.

Public notices required by the code must be written so that they are easy to read and understand by a person within an elementary education. Before an application can be filed with the state siting agency, the proponent must give certain public notice of the proposal, provide an opportunity for public comment about the proposal, conduct public information sessions in one or more communities near the facility, and provide written notice to property owners within the proposed final route or alternate routes as soon as practicable after those routes have been identified. The same notice is required to amend an approved siting certificate, although different review procedures apply.

The application for a facility is detailed. It includes a statement of need for the facility; a description of the facility, its route, and one or more alternative routes; the cost of the proposed facility and alternatives to it; baseline environmental and socioeconomic data for the proposed and alternate routes; EMF measurements, projects, and mitigation measures; environmental impacts of the proposed and alternative routes; and public comments received at public meetings in the area, among other requirements. A copy of the application must be provided to local, state, and federal agencies with an interest. Public notice also must be given.

The state siting agency has 45 days in which to review an application for completeness. It has 10 months in which to undertake an intensive study of the application and issue a report and a proposed decision that includes the following considerations:

- The need for the facility
- Sensitive areas and areas of concern
- Impacts on local services/infrastructure
- Stream crossing/water quality impacts
- Effects on terrestrial/aquatic biology
- Audible noise and RF interference
- Environmental impacts
- Impacts on historic, architectural, archeological, and cultural resources
- Consistency with preferred route criteria
- Land use considerations
- Geologic suitability of the route
- Scenic and visual impacts
- Impacts on threatened/endangered species
- Air quality impacts
- EMF
- Construction and mitigation plans

To approve or conditionally approve a siting certificate, the siting agency must find there is a need for the facility, and it is reasonably likely to have a positive effect on system economies. Adverse environmental impacts must have been identified and minimized, considering available technology and the nature and economics of alternatives; monitoring, mitigation, and restoration plans are required to address these impacts. The facility must be consistent with applicable energy resource and utility plans. The facility must serve the public interest, convenience, and necessity, but the agency is prohibited from discriminating between intrastate and interstate lines, including lines built solely to serve needs outside the state. The facility must be built within 5 years.

The agency must provide its report and proposed decision to all parties who received notice of earlier proceedings and anyone who requests it. A summary must be published in newspapers in areas near the facility. Within 45 days after publication, the agency holds one or more public hearings regarding the decision in the areas near the facility and written comments can be submitted. Within 30 days thereafter, the agency issues a proposed order that addresses all comments received and is served on all parties.

The applicant can petition for review of the proposed order within 10 days thereafter in which case all issues are reconsidered. Other people may petition for review within 30 days after it is published, if they participated in earlier proceedings or were prevented from doing so meaningfully, in which case, only issues raised in the petition are reviewed. The proposed order becomes a final order if a timely petition for review is not filed.

If review is petitioned, then there is at least one prehearing conference held to identify issues, witnesses, and documents relevant to the review. A prehearing order is issued addressing those issues. Exchange of information by active parties is required. Discovery is allowed and may be compelled before the hearing. New evidence can be introduced at the hearing only for good cause shown. Cross examination of witnesses is allowed. A hearing is held in the county seat of the community(ies) where the facility is proposed. The hearing is held and a report and proposed decision are issued generally within 120 days after notice of the hearing is published. Parties can file exceptions to the decision within 30 days after it is served. The review agency may hold a hearing to accept oral arguments regarding the exceptions. Within 30 days after the last day for filing exceptions, the reviewing agency issues its final decision. Provisions are made for monitoring, revocation or suspension of a permit, civil liabilities, enforcement, and judicial review.

The model also contains a policy statement about electric and magnetic fields (EMF). The statement recognizes ongoing efforts to understand more about EMF. Due to uncertainties, exposure to EMF is to be considered and minimized. Potential mitigation measures include design alternatives that reduce EMF at the edge of the right of way, including spatial arrangements and phasing of conductors, uprating interior lines, increasing tower heights, and widening right of way corridors; distancing lines from population centers or potentially sensitive land uses; and considering EMF as an environmental impact in the route selection process.

Glossary

Air quality analysis. Analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification.

Allowances. Permissions to emit a ton of a specific pollutant_are then issued to emission sources.

Attainment area. An area which currently does meet NAAQS for a given criteria pollutant.

Best Available Control Technology (BACT). An emission limitation determined the regulatory authority that must be applied to a source subject to PSD permitting.

British Thermal Unit (Btu). The quantity of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit between 32_ F and 212_ F.

Cap. A limit on the tons of a pollutant that can be emitted in a specific period for a specific sector and/or region. A cap is sometimes called an *emission budget*.

Clean Air Act (CAA). Legislation to protect ambient air quality, enacted in 1970 by Congress and amended mostly recently in 1990.

Contemporaneous. Generally, changes in emissions occurring at a site within a period beginning 5 years before the date construction is expected to commence and ending when the emissions increase from the modification occurs.

Criteria pollutants: Pollutants for which National Ambient Air Quality Standards (NAAQS) have been set by the EPA:

- Carbon monoxide (CO)
- Nitrogen oxides (NO_x)
- Sulfur dioxide (SO_2)
- Particulate matter (PM/PM-10) [75]
- Ozone
- Lead

District energy plant. A facility that produces steam, hot water and/or chilled water for distribution through a network of pipes to multiple buildings to meet thermal energy needs, including space heating, air conditioning, domestic hot water and industrial processes.

Emissions unit. Any part of a stationary source that emits or has the potential to emit any pollutant subject to regulation under the Act.

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[75] EPA has designated PM-10 (particulate matter with an aerodynamic diameter less than 10 microns) as a criteria pollutant by promulgating National Ambient Air Quality Standards (NAAQS) for this pollutant as a replacement for total particulate matter (PM). Thus, the determination of potential to emit for PM-10 emissions as well as total PM emissions is required in applicability determinations.

Fugitive emissions. As defined in the federal PSD regulations, fugitive emissions are those "...which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening."

Lowest Achievable Emissions Rate (LAER). An emission limitation determined by the regulatory authority that must be applied to a source subject to NAA permitting.

Major source. A new source that has the potential to emit any pollutant regulated under the Act in amounts equal to or exceeding specified major source thresholds which are predicated on the source's industrial category.

Major modification. A physical change or change in the method of operation at an existing major source that causes a *net emissions increase* of any regulated pollutant that is considered *significant*.

MMBtu. Million Btu (British Thermal Units).

National Ambient Air Quality Standards (NAAQS). Standards set by the EPA that limit the allowable outdoor concentration of criteria pollutants.

Net emissions increase. Emissions <u>increases</u> associated with the proposed source or modification, minus source-wide emissions <u>decreases</u> that are creditable and contemporaneous, plus source-wide emissions <u>increases</u> that are creditable and contemporaneous.

New Source Review (NSR). Program for <u>pre-construction</u> review and permitting of new emission sources.

New Source Performance Standards (NSPS). Emission standard prescribed for criteria pollutants from certain stationary source categories under Section 111 of the Clean Air Act.

Non-attainment area. An area which currently does not meet NAAQS for a given criteria pollutant.

Non-Attainment Area (NAA). The New Source Review program applicable to sources located in areas that are not in attainment for a given criteria pollutant.

Point emissions units. Emissions occurring from a specific point or piece of equipment, at which emissions can be monitored.

Potential to emit. Capability at maximum design capacity to emit a pollutant, except as constrained by federally-enforceable conditions.

Prevention of Significant Deterioration (PSD). The New Source Review program applicable to sources located in areas that are in attainment for a given criteria pollutant or in unclassifiable areas.

PSD increment. The maximum allowable <u>increase</u> in concentration that is allowed to occur above a baseline concentration for a pollutant in an attainment area.

Significant Emissions Increase. Threshold increases in net emission in a major modification as set for each pollutant by EPA.

Source-wide. Occurring anywhere within the entire stationary source.

Stationary Source. Any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Clean Air Act (the Act). "Building, structure, facility, or installation" means all the pollutant-emitting activities that:

- belong to the same Standard Industrial Classification (SIC) major group (2-digit SIC code);
- are located on one or more contiguous or adjacent properties; and
- are under common ownership or control.

Support facility. Facility that conveys, stores, or otherwise assists in the production of the principal product of another facility.