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RESTRUCTURED ELECTRICITY MARKETS

Three States' Experiences in Adding Generating Capacity

GAO

Accountability * Integrity * Reliability

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Abbreviations

BTU	British thermal unit
CEC	California Energy Commission
DEP	Department of Environmental Protection
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Council
PUC	Public Utility Commission
RDI	Resource Data International
TNRCC	Texas Natural Resource Conservation Commission

United States General Accounting Office
Washington, DC 20548

May 24, 2002

The Honorable Stephen Horn
Chairman, Subcommittee on Government Efficiency,
Financial Management and Intergovernmental Relations
Committee on Government Reform
House of Representatives

The Honorable Doug Ose
Chairman, Subcommittee on Energy Policy, Natural
Resources and Regulatory Affairs
Committee on Government Reform
House of Representatives

In response to the Energy Policy Act of 1992, the Federal Energy Regulatory Commission, 24 states, and Washington, D.C., restructured electricity markets by shifting from service provided through a regulated monopoly—the local electric utility—to service provided through open competition among the local utility and its competitors. The 24 states and Washington, D.C., accounted for about 55 percent of total U.S. electricity retail sales in 1999. The restructuring was intended to increase competition and expand consumer choice in order to lead to increased efficiency and lower prices. In states that have restructured, decisions about whether to build new power plants to add to a region's generating capacity are made by independent developers—private companies not regulated by state utility commissions. Previously, the utilities and states' utility regulators made these decisions. To evaluate the adequacy of supplies of electricity, the North American Electricity Reliability Council—a voluntary organization of utilities—forecasts the generating capacity needed to meet future electricity demand.

Federal and state environmental laws have historically made the fossil fueled electric power generation industry, which relies on coal, oil, and natural gas, one of the most highly regulated industries, according to the U.S. Environmental Protection Agency (EPA). These large plants emit pollutants into the air and may also discharge pollutants into water systems. In addition, these power plants can occupy large areas of land, in some cases about 30 acres, and as a result, could harm wildlife and ecosystems. Consequently, power plant developers generally have to address air and water quality, and may also have to address endangered species issues when obtaining pre-construction and operating permits. EPA has delegated responsibility to many states for enforcing compliance with both the Clean Air Act and the Clean Water Act. The developer, state agencies, and the U.S. Fish and Wildlife Service are responsible for ensuring that a power plant project does not adversely affect any endangered or threatened species. State and local agencies review developers' applications for environmental and other permits needed to build new power plants in restructured markets, as they did before restructuring.

Restructuring issues gained national visibility in May 2000, when California's electricity prices rose dramatically, with average costs rising four-fold. This increase in prices occurred, in part, because the total demand for electricity was too close to the total electricity supplies. Industry experts cited the limited development of new power plants within California as one contributor to the crisis. While prices subsequently fell, experts remain concerned that the planned development of new power plants may not be sufficient to meet future needs in California. In response to California's experience, some states have delayed or suspended their plans to open their markets to competition, while other states have decided against restructuring their electricity markets at this time.

Citing the importance of quickly adding new power plants when needed as a key factor in balancing the supply and demand for electricity in restructured markets, you asked us to compare the experience of California in adding new power plants with the experiences of two other restructured states—Pennsylvania, which operates as part of an innovative regional electricity market, and Texas, which has successfully added new plants. In response, we agreed to (1) compare the need for electric power in California, Pennsylvania, and Texas, as well as the extent to which these states have added new generating capacity; (2) compare the states' regulatory processes for approving new power plants; (3) compare the states' rules for connecting new power plants with local electricity transmission systems; and (4) identify the key factors that independent developers consider in deciding where to propose new power plant projects. In 1999, power plants in California, Pennsylvania, and Texas accounted for 21 percent of the generating capacity in the United States—about 166,000 megawatts of power. One megawatt is sufficient to meet the demand of 750 households.

To compare California's experience with those of Pennsylvania and Texas, we analyzed state and industry data on power generation needs and developers' proposals to build power plants and visited each state to interview cognizant state and federal officials. To identify the factors that power plant developers consider in making investment decisions, we met with six independent private developers—three of these were among the largest and the other three were smaller; a manufacturer of large turbines used to generate electricity; and representatives from the financial community, including two investment ratings companies and four investment banks that help finance power plants. Our detailed scope and methodology is presented in appendix I.

Results in Brief

In 1995, Texas had the greatest identified need of the three states for additional electric power, and it added the most new capacity from 1995 through 2001—more than twice as much as the North American Electricity Reliability Council forecasts indicated would be necessary through 2004. In contrast, over this period, California added about 25 percent of the forecasted need for capacity through 2004. Although Pennsylvania added less than half of its forecasted need for capacity, the state continues to be a net exporter of electricity to nearby states. Of the 49,600 megawatts of capacity built or under construction in these three states between 1995 and 2001, 59 percent was in Texas, 24 percent in California, and 17 percent in Pennsylvania. More recently, partly because of the national economic slowdown, the terrorists' attacks on September 11, and the collapse of Enron Corporation, developers have cancelled or postponed 23,000 of the 68,000 megawatts of proposed capacity not yet under construction in the three states.

The three states have similar processes for approving applications to build and operate new power plants, although California requires an additional approval. In all three states, state and local agencies must review the applications to ensure that the developer complies with environmental, land use, and other requirements before issuing the permits necessary to build and operate a power plant. In addition, California has a state energy commission that reviews each power plant application to determine whether the benefits of additional electricity outweigh its likely negative environmental or other effects. From 1995 through 2001, obtaining regulatory approval for building new power plants in California and Pennsylvania took 14 months, on average, compared with 8 months, on average, in Texas. Furthermore, the duration of the regulatory review process was less predictable in California than in the other two states—approval for 5 of California's 21 medium- to large-scale projects took 18 months or longer. In California and Pennsylvania, most plants were proposed for areas with air quality that did not meet federal standards; in Texas most proposals were for areas that met these standards. As a result, over 60 percent of the plants approved in California and Pennsylvania needed to install more advanced pollution control equipment to obtain an air quality permit, while only 18 percent of the approved power plants in Texas had to meet the more stringent requirements.

Texas' rules for connecting new power plants to the electricity transmission system are less costly for independent developers and administratively simpler than the approaches California and Pennsylvania use. Regarding costs, Texas requires developers to pay only for the direct costs of connecting the plant to the local transmission system, not for any upgrades to the transmission system to carry the additional capacity; instead, consumers pay for the cost of these upgrades directly through their electricity bills. In contrast, under market rules approved by the Federal Energy Regulatory Commission for California, Pennsylvania, and many other states, developers must pay for both direct costs and upgrades. For upgrade costs, developers negotiate with the transmission system owner over the necessity and degree of upgrades, as well as the allocation of these costs. Developers will seek to recover these costs through electricity sales once the plant is operating. Furthermore, Texas' rules are administratively simpler than those in the other two states because Texas requires developers and local transmission system owners to use a standard agreement that specifies responsibilities of each party for connecting new power plants. The agreement also ensures that local transmission owners provide comparable treatment for their own power plants and those of independent developers, as the commission requires for restructured electricity markets. In contrast, California and Pennsylvania allow developers and the local transmission system owner to negotiate their responsibilities for each project. The process for completing an agreement in Texas took less than half the time it took the other two states. In November 2001, the Federal Energy Regulatory Commission requested comments and suggestions for developing a standard agreement. We believe such standard agreements make sense as a first step because, in Texas, they expedited the process of connecting a power plant to the transmission system. In the longer term, we believe that clarifying the allocation of upgrade costs offers additional benefits for facilitating the connection process and potentially power development. Accordingly, we are recommending that the Federal Energy Regulatory Commission develop a standard agreement for connecting new power plants to the electricity transmission system and clarify how the local transmission owner and developer should allocate costs to upgrade a transmission system.

In deciding where to build new power plants, independent developers said they weigh a market's risks, including uncertainty about changes in a state's market rules, against expected profits—higher risks require higher expected profits. For example, developers prefer market rules that allow the use of long-term contracts that set a minimum price for electricity to ensure a certain level of profits. According to developers and electricity industry experts at investment firms we interviewed, Pennsylvania and Texas provided transparent rules and opportunities to manage their risk, giving these developers and experts greater assurance of reasonable profits. In contrast, these developers and experts said California's market structure before the electricity crisis began in May 2000 attracted less investment because (1) developers could not enter into long-term contracts or use other risk management tools and (2) market prices were low. Developers added that some of California's responses to the electricity shortages during 2000 and 2001—such as the state's direct involvement in the market through electricity purchases—increased the risk of entering the market and contributed to cancellations and delays of many proposed projects and may affect future investment.

Background

Before restructuring, electric service was provided primarily by federal- and state-regulated investor-owned electric utilities. A utility typically owned the power plants, transmission system, and local distribution lines that supplied electricity to all of the consumers in a geographic area. Under this system, the Federal Energy Regulatory Commission (FERC) regulated, among other things, sales of electricity for resale and the transmission of electricity over high-voltage power lines in interstate commerce.[1] The states regulated retail markets by participating with utilities in forecasting growth in demand, planning and building new power plants, reviewing and approving utility costs, and establishing rates of return.

In response to the enactment of the Energy Policy Act of 1992, FERC has opened wholesale electricity markets across the country,[2] and many states have also opened their retail markets to competition. In these competitive markets, consumers will eventually pay market-based electricity prices, and power plant developers are no longer guaranteed that construction costs will be repaid or that the electricity produced will be sold profitably. In these markets, it was expected that independent developers would individually assess the need for new generation and its potential

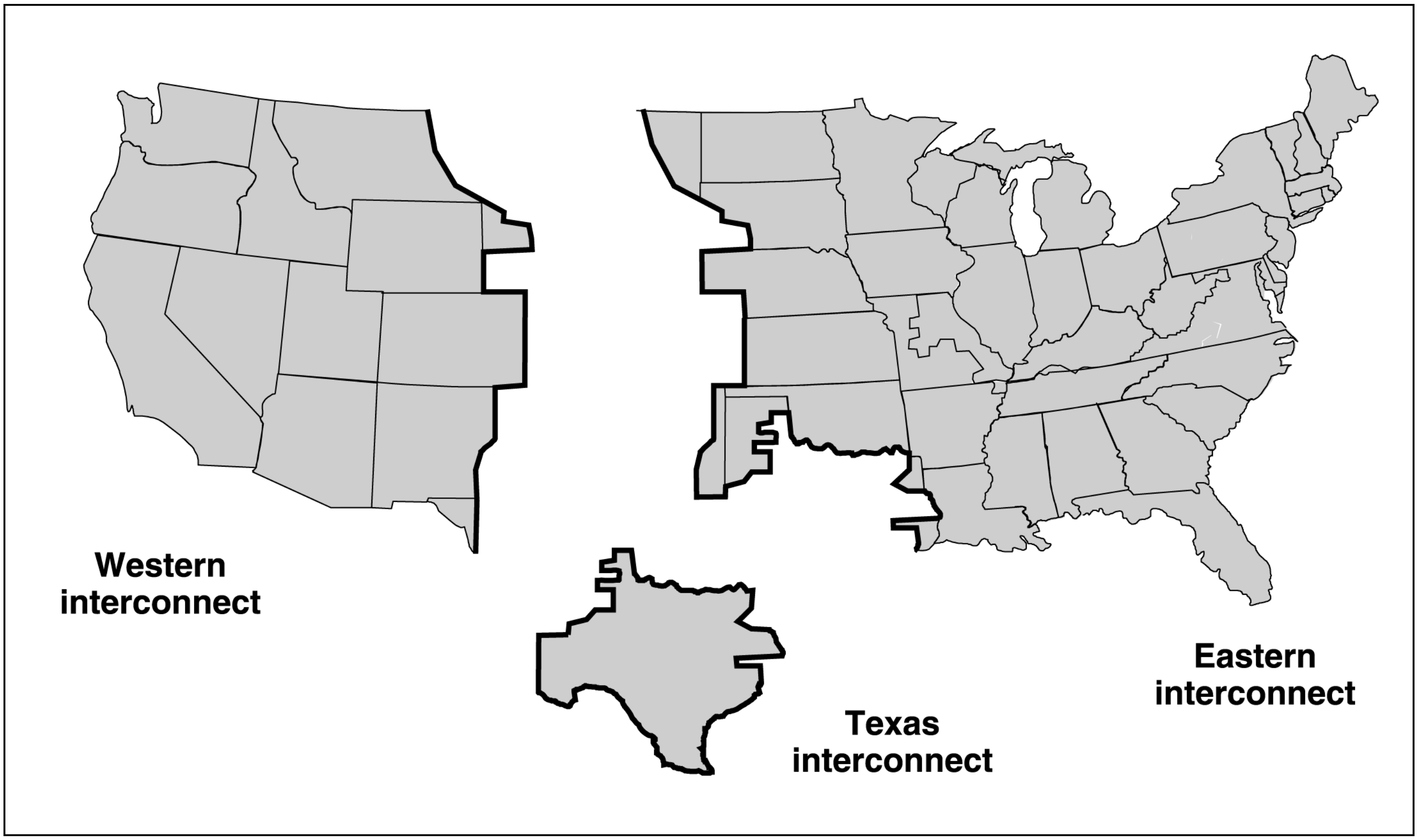
[1]FERC does not regulate most of Texas' electricity system because it is an independent transmission region that does not engage in interstate commerce.

[2]Texas similarly opened its wholesale market to competition in 1995.

profitability. These assessments would be made on the basis of market signals, such as the prices of electricity and other related products and forecasts of the generation required to meet growing demand.

As shown in figure 1, the U.S. electricity transmission system consists of three connected, but independently operating systems: the western interconnect, the eastern interconnect, and the Texas interconnect. Each of these systems must maintain a constant balance between the amount of electricity supplied by power plants and the amount of electricity being used at homes and businesses. While little electricity moves from one system to another, electricity produced within each system can move throughout the system, subject to transmission system constraints that can limit or prevent the flow of electricity within certain regions of the system. The level of electricity demand varies considerably throughout the day, with the highest levels only reached during a small percentage of the hours during a year. In addition, unlike other commodities, electricity cannot easily or inexpensively be stored and must be instantly available whenever demand increases. Because these systems are interconnected, a change in the supply or demand in one part of the system can affect producers and consumers elsewhere. To ensure that supply exceeds the demand for electricity, utility systems have historically maintained additional power plants, as part of a reserve margin, above the amount needed to meet the highest level of expected demand. This reserve margin has enabled utilities to meet demand when a power plant was taken out of service or when demand rose more than expected.

Figure 1: The Major U.S. Electricity Transmission Interconnections



As part of the western interconnect, California has historically imported about 20 percent of the electricity that it consumes. While California's utilities had owned power plants located in California and other states as part of their supply mix before restructuring, they have since sold most of these plants to private companies not regulated by California. In contrast, in recent years, Pennsylvania has exported more electricity than it has imported. Although some of the power plants owned by the state's former utilities were sold as a result of restructuring, the plants have long-term contracts to sell electricity in Pennsylvania. Power plants in Texas generate nearly all of the electricity that the state consumes. The state's utilities have leased access to generating capacity at some of their plants and some have been sold; however, the utility plants that are leased are operated by subsidiaries of the former utilities.

As part of its efforts to restructure the industry, FERC issued regulatory orders that require transmission system owners to allow all parties, including new power plant developers, to transmit electricity under comparable terms and conditions. FERC has approved the formation of independent organizations to operate the transmission system in California and other states. An example of this new type of organization is the PJM Interconnect, which operates the transmission system in all or parts of Pennsylvania, New Jersey, Maryland, Delaware, and Washington, D.C. FERC also directed transmission system owners to create multistate regional transmission organizations to operate the systems independently of the transmission owners.[3]

To maintain the reliability of the transmission system, transmission owners and operators participate in the North American Electricity Reliability Council (NERC) through 10 regional reliability councils. These regions cooperate in planning and integrating the transmission system and study trends in long-term supply and demand.

U.S. electricity markets have attracted significant planned investment to the nearly 770,000 megawatts[4] of generating capacity already on-line at the end of 1995. Through the end of 2001, developers had proposed or added about 690,000 megawatts of new electricity generating capacity, of which about 114,000 megawatts were already built[5] and another 123,000 megawatts were under construction. Industry data indicate that about 104,000 megawatts of proposed plants had been either tabled or cancelled—with the remainder in various stages of planning or development. About 40 percent of the proposed generating capacity was planned for states identified as active in implementing restructured electricity markets, and 20 percent for states that have actively pursued electricity restructuring but have either delayed or suspended further actions.

[3]Alternatively, FERC's Order 2000 provides that transmission owners may file with FERC an explanation of what actions they have taken to create a regional transmission organization and a reason why they will not join such an organization.

[4]A watt is a unit of electrical power. A kilowatt is 1,000 watts. A megawatt is 1,000,000 watts. One megawatt can serve the needs of about 750 homes. One kilowatt used for one hour equals 1 kilowatt-hour.

[5]This reflects new generating units placed on-line from 1995 through 2001.

While coal, nuclear power, water (hydroelectric dams), and oil are the primary fuels for older power plants, natural gas-fueled power plants accounted for over 80 percent of the generating capacity added from 1995 through 2001 and a similar percentage of the plants proposed for construction through the end of 2001. About 62 percent of the gas-fired plant capacity proposed through 2001 would use highly energy-efficient combined-cycle technologies, and 35 percent would use simple-cycle technologies. Both types of power plants rely on large gas turbines, also called combustion turbines, with combined-cycle units adding a steam generator and a steam turbine to convert waste heat in the exhaust stream to electricity. In general, both types of plants are more fuel efficient, less costly to operate, and less polluting[6] than many existing power plants. Because of their higher efficiency and relatively low operating costs, combined-cycle power plants are often used to generate electricity through large portions of the day. In contrast, simple-cycle power plants typically are used to generate electricity only during periods of high demand because they cost more to operate. These plants are useful in meeting sudden changes in demand because they can reach full output in as little as 10 minutes. In general, simple-cycle power plants can be constructed in about 6 to 9 months after regulatory approvals, while combined-cycle power plants need from 18 to 28 months.

The Three States Had Different Needs for Additional Electric Power and Added Different Amounts

Electricity demand in Texas, California, and Pennsylvania grew faster from 1995 through 2001 than NERC had forecast in 1995. In response, in Texas, developers added the most new capacity—about 16,200 megawatts, or more than double the forecasted need through 2004. In contrast, in California, developers added about 4,600 megawatts, or 25 percent of the forecasted need for capacity through 2004, and in Pennsylvania, developers added about 2,100 megawatts, or less than half of its forecasted need through 2004. More recently, each state has seen significant cancellations and postponements of projects, with California experiencing the greatest drop. Developers and investment firms noted that events in the past year—the economic downturn, the terrorists' attacks on September 11, and the collapse of the Enron Corporation—contributed to the cancellation of many proposed projects in the United States and the world.

[6]New combined-cycle power plants emit lower levels of air pollutants, such as nitrogen oxide and sulfur dioxide, as well as lower levels of carbon dioxide.

The States Had Different Needs for New Power Plants

In 1995, when U.S. electricity markets were beginning to restructure, NERC forecast that already planned new plant construction would adequately meet the needs of the regional markets that include each of the three states through 2004. Specifically, NERC forecast the following for each of the reliability regions encompassing the states we reviewed:

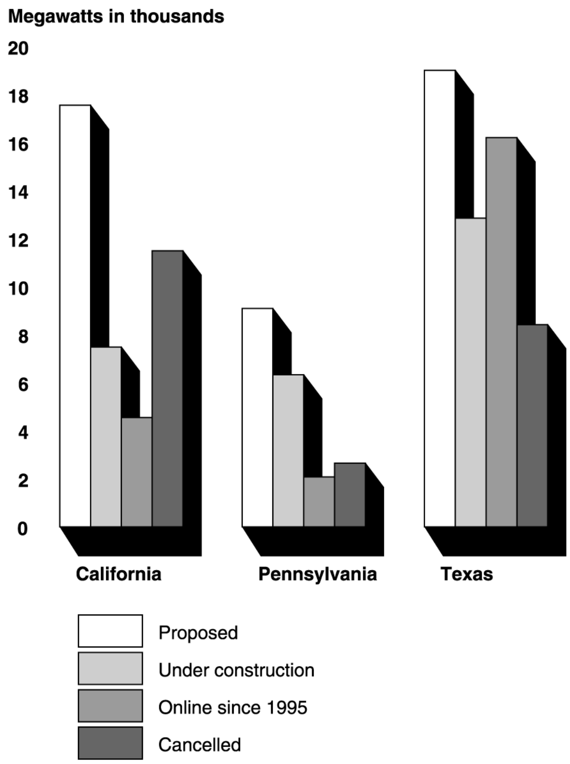
- For California, the 16,800 megawatts of additional planned capacity would adequately meet an estimated 1.8 percent growth in peak demand per year. This added capacity included 13,600 megawatts of generating capacity and 3,200 megawatts of reduced demand to be achieved through the utilities' conservation and load management programs.
- For Pennsylvania, the 5,700 megawatts of additional planned generating capacity would adequately meet an estimated 1.3 percent growth in peak demand per year.
- For Texas, the 6,600 megawatts of additional planned generating capacity would adequately meet an estimated 2.1 percent growth in peak demand per year. Texas' planned new power plants included 5,300 megawatts of new gas-fueled simple-cycle and combined-cycle power plants.

Since NERC's 1995 report, electricity demand in each market has grown more than expected. Specifically, in 2001, the data for the three reliability regions reflected the following annual average growth: 4.7 percent for California, 2.1 percent for Pennsylvania, and 4.9 percent for Texas. NERC also reported that independent developers would need to continue to add new power plants in order to meet demand over the next 10 years.

More Capacity Was Proposed and Built in Texas Than in the Other Two States

According to industry data through 2001, developers had announced proposals to build about 118,000 megawatts of new generating capacity in California, Pennsylvania, and Texas—substantially more than NERC's projection of about 26,000 megawatts by 2004. Figure 2 shows that nearly half of this new capacity was proposed for Texas, while 35 percent was proposed for California and 17 percent for Pennsylvania.

Figure 2: Generating Capacity Proposals in the Three States, as of December 31, 2001



Source: GAO compilation of Resource Data International data.

In addition, developers generally proposed power plants earlier in Texas than in the other two states. Specifically, 69 percent of the new power plant projects that began the regulatory process in Texas were proposed to regulators before 2000, while 75 percent of the projects in California and Pennsylvania were proposed to regulators in 2000 and 2001.[7] This early interest in entering the electricity market in Texas led to earlier consideration by regulatory agencies involved in the siting approval process.

Partly because developers had proposed new power plants earlier, they had built more generating capacity in Texas than in the other two states by the end of 2001. In total, Texas accounted for about 71 percent, or 16,000 megawatts, of the 23,000 megawatts of generating capacity built in the three states from 1995 through 2001. California accounted for 20 percent, or 4,500 megawatts, and Pennsylvania accounted for only 9 percent, or 2,000 megawatts, of generating capacity.

In addition to plants already built by the end of 2001, developers had more capacity under construction in Texas than in either of the other two states. Total capacity under construction in the three states was almost 26,700 megawatts: almost 13,000 megawatts, 48 percent, in Texas; about 7,500 megawatts in California; and about 6,400 megawatts in Pennsylvania.

All Three States Have Experienced Significant Cancellations in Recent Months

As of December 2001, developers had cancelled or postponed over 22,600 megawatts of capacity previously announced for the three states, according to industry data. In particular, 59 proposed power plants were reported cancelled or postponed in California, amounting to about 11,500 megawatts of generating capacity. Although California accounted for only 35 percent of proposed new capacity for the three states from 1995 through 2001, it accounted for 51 percent of the cancelled or delayed capacity. Just as the emergence of the electricity shortfalls and high prices in California in 2000 led to an influx of proposals to build new power plants, the subsequent drop in electricity prices preceded the cancellations in the state. While cancelled or postponed projects represented about 28 percent of proposed additions to total generating capacity in California as of December 31, 2001, cancelled or postponed projects represented only about 13 percent of the total additions to capacity proposed in Pennsylvania and about 15 percent of proposed capacity in Texas.

[7] In California, of the power plant projects proposed from 1995 through 2001, 72 percent were submitted after electricity shortages began in May 2000.

Recent Events May Limit Planned Construction and Additional Plans

Senior electricity industry analysts at investment firms told us that the combination of three events during the past year—the national economic slowdown, the terrorists' attacks on September 11, and the collapse of Enron Corporation—have further limited developers' near-term ability to propose and build new power plants because the international capital markets are less willing to invest in energy projects. They explained that the slowdown has reduced economic growth and expected growth in electricity demand. The terrorist attacks have, among other things, made insuring and re-insuring all power plants more difficult and more expensive. In addition, they said, the collapse of Enron, while not specifically hurting energy markets, has increased concern about the financial condition of energy companies and led to, among other things, (1) higher lending standards, (2) lower levels of allowed borrowing, and (3) higher interest rates for borrowing. In addition, the stock prices of many major independent developers have dropped substantially, further limiting their ability to raise capital.

Regulatory Processes Are Generally Similar in the Three States, Although California Requires an Additional Approval

In the three states we reviewed, state and local agencies responsible for air and water quality and land use decisions review applications for constructing and operating power plants to ensure compliance with relevant laws and regulations. In addition, California requires the California Energy Commission (CEC) to approve all power plant projects with at least 50 megawatts of capacity. Because most developers in California and Pennsylvania have chosen sites for new plants in areas that have poor air quality, environmental agencies generally conducted more comprehensive reviews and required stricter limits on emissions. Both California and Texas provide enhanced public participation during the application review process, which can add time to the approval process to address sensitive issues.

The States Use Similar Review Processes but California Adds Another Level of Review

In California, 1 of 35 regional air districts and one of 9 regional water boards, or EPA's Region 9 in some parts of the state, review the application to assess the proposed project's compliance with air and water quality requirements. Local governments review the applications for compliance with land use and zoning requirements. If applicable, state and federal agencies review the application for compliance with the Endangered Species Act. In addition to these reviews, CEC must approve new power plant projects above 50 megawatts before they can be built, adding another layer of review. According to the state, CEC exists to ensure that needed energy facilities are authorized in an expeditious, safe, and environmentally acceptable manner. As part of its role, CEC oversees compliance with the California Environmental Quality Act, which requires an evaluation of the environmental impact of state-approved projects planned for the state. CEC decisions can overturn the permitting decisions of other state and local agencies. In one case, for example, CEC approved a power plant even though the local community had refused to grant a land-use zoning permit. CEC also analyzes other aspects of the project, which may not be examined by other agencies, including the plant's technical design, fuel use and efficiency, transmission equipment, and socioeconomic impacts. The CEC certification process allows for public participation throughout the application review process. (See app. II.) In California, the average period for approval was 14 months, excluding smaller plants that were approved under the state's temporary 21-day emergency siting process.[8] Approvals for large plants—those with generating capacity of more than 200 megawatts—took about 16 months.

Pennsylvania has no single state agency specifically responsible for approving new power plant projects. As with other industrial projects, power plant developers must work through (1) the Pennsylvania Department of Environmental Protection to obtain air quality and water quality permits and (2) local government agencies to obtain zoning and other land-use permits. In addition, developers in eastern or central Pennsylvania would have to obtain permits from the Delaware River Basin Commission or the Susquehanna River Basin Commission, respectively, for access to river water. If applicable, federal and state agencies review the application for compliance with the Endangered Species Act. (See app. III.) The primary permit needed for approval to construct a power plant is the air quality permit, and from 1995 through 2001, the average time needed to obtain this permit was about 14 months. Approvals for plants larger than 200 megawatts took about 13 months.

Similarly, Texas has no single state agency specifically responsible for approving new power plant projects. Instead, the Texas Natural Resource Conservation Commission is responsible for approving environmental permits and in some cases, municipal governments regulate land use

[8] In response to the electricity crisis, California authorized expedited reviews of (1) 21 days for small plants that operate only during peak demand periods, (2) 4 months for simple-cycle plants, and (3) 6 months for combined-cycle and steam power plants with no adverse environmental impacts. CEC approved 11 projects under the 21-day process. In August 2001, the California State Auditor, using a different time period, reported that CEC review and approval took 14 months, on average. See *California Energy Commission: Although External Factors Have Caused Delays in Its Approval of Sites, Its Application Process Is Reasonable.*

through the zoning process. If applicable, federal and state agencies review the application for compliance with the Endangered Species Act. (See app. IV.) For plants approved from 1995 through 2001, developers obtained an air quality permit—the primary permit required—in 8 months in Texas. Approvals for plants larger than 200 megawatts also took about 8 months.

Table 1 shows the time it has taken to complete the approval process in each of the three states. As the table shows, the time to complete the review process was less predictable in California than in the other two states—approval for 5 of California's 21 medium- to large-scale projects took 18 months or longer.

Table 1: Regulatory Approval Time Frames for Power Plants in California, Pennsylvania, and Texas

	California[a]		Pennsylvania		Texas	
Time for regulatory approval	**Projects**	**Percent**	**Projects**	**Percent**	**Projects**	**Percent**
6 months or less	4	19	2	9	17	25
6 months to 1 year	5	24	12	55	43	64
1 to 1-1/2 years	7	33	6	27	7	10
1-1/2 to 2 years	3	14	0	0	0	0
More than 2 years	2	10	2	9	0	0
Total	**21**	**100**	**22**	**100**	**67**	**100**[b]

[a]Includes three projects that CEC approved under the expedited 4-month and 6-month processes, but excludes the plants approved under the temporary 21-day expedited process for peak-demand use.

[b]Does not add due to rounding.

Sources: CEC, the Pennsylvania Department of Environmental Protection, and the Texas Natural Resource Conservation Commission.

Most Approved Power Plants in California and Pennsylvania Are Located in Areas with Stringent Air Quality Requirements

The gas-fired power plants now being built emit nitrogen oxides, which directly contribute to ozone pollution.[9] To control these emissions, air pollution control requirements for these power plants vary according to the planned location and the amount of the plants' emissions, as well as whether a state has stricter standards than the federal standards. In general, large power plants planned for an area that does not meet federal

[9]Ozone is not directly emitted into the air. Instead, it is produced in the atmosphere through the interaction of volatile organic compounds, nitrogen oxides, and sunlight. Fossil-fueled power plants emit nitrogen oxides.

air quality standards[10]—known as non-attainment areas—must obtain a Non-Attainment New Source Review permit.[11] This permit requires a new power plant to install the most advanced pollution control equipment[12] and offset the new plant's emission of pollutants by reducing emissions elsewhere in the area. The new power plant could, for example, buy emission reduction credits, called offsets, from another industrial facility that has closed or adopted less polluting technology beyond what is required under regulations. The advanced pollution control equipment and the purchase of these offsets from another company can add substantially to a power plant's costs compared with the requirements in an attainment area. In attainment areas—areas that meet federal air quality standards—plants can obtain a Prevention of Significant Deterioration permit, which requires less stringent technologies to control emissions.[13]

As shown in figure 3, all three states have non-attainment areas for EPA's ozone standard. Substantial portions of California and Pennsylvania are non-attainment areas with many areas of either extreme or severe air quality impairment. In addition, because Pennsylvania is part of a regional ozone transport area, the entire state must be treated as a non-attainment area. In contrast, only the Dallas, Houston, Beaumont, and El Paso metropolitan areas are non-attainment areas for ozone in Texas. Overall, 65 percent of the approved plants in California and about 60 percent of the approved plants in Pennsylvania were required to obtain air permits requiring more stringent controls, primarily because power plant projects for California and Pennsylvania generally were proposed for sites in non-attainment areas for ozone. In contrast, in Texas, only 18 percent of

[10]EPA has established health-based air quality standards, as part of the National Ambient Air Quality Standards, for ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, particulate matter, and lead.

[11]Developers can avoid stringent Non-Attainment New Source Review requirements if a power plant's emissions are below the regulatory threshold. This can be done by limiting a plant's operations to a fixed number of hours per year or by using a process called "netting," which allows a developer at an existing facility, such as a refinery or power plant, to offset the increase in emissions of the new equipment by reducing the existing facility's emissions.

[12]Plants with large amounts of emissions that are planned for non-attainment areas are generally required to install equipment capable of meeting the Lowest Achievable Emission Rate (LAER).

[13]Plants with large amounts of emissions planned for attainment areas are generally required to install the Best Available Control Technology (BACT).

the approved plants had to use more stringent controls, partly because 64 percent of the approved plants were located in attainment areas.[14]

Figure 3: Ozone Non-Attainment Areas for EPA's 1-Hour Standard as of January 2002

Source: EPA.

California has led other states in requiring pollution reduction beyond what is federally required. Specifically, California has a 1-hour ozone

[14]Of the approved power plant projects in non-attainment areas, 50 percent did not require more stringent control technologies in Texas, 41 percent did not require these technologies in Pennsylvania, and 28 percent did not require them in California. As a result, these power plants are allowed to have higher emission rates than otherwise would have been allowed under a Non-Attainment New Source Review permit.

standard of 0.09 parts per million, as compared with EPA's 0.12 parts per million standard—which causes more areas of the state to be judged as having poor air quality. With this standard, power plants in almost all areas of the state must install some pollution controls. California requires that smaller gas-fired power plants must limit their emissions—even those with significantly lower quantities of emissions. Plants emitting more than 10 pounds per day of pollutants, or approximately 1.8 tons per year, must evaluate pollution controls. In contrast, EPA has a minimum threshold of 10 tons per year for plants located in areas with the worst air quality. Because California's standards are more stringent than EPA's, 9 of the 31 power plant projects approved in California since 1995 had to install pollution control equipment to lower their emissions, which EPA would not have required.

Furthermore, while EPA's standards for new plants apply in all states, the approved emissions level for a plant depends on how the state applies EPA's regulations. California generally required new power plants to reduce emissions to lower levels than did other states. These lower levels subsequently are considered by other states in setting their own BACT and LAER standards.

All Three States Seek Public Comments on a Project, and California and Texas Allow the Public to Participate in Hearings

Each of the three states allows for public involvement at several stages in the permit review process, including the local community's consideration of zoning and other land-use permits and the state agency's consideration of environmental permits. Permitting decisions also can be appealed to the state courts and, in some cases, to a state or federal agency.

In addition, both California and Texas allow members of the public to become formal participants in the process for a power plant application. In California, CEC can designate them as approved "intervenors," which enables them to request data from the applicant, file motions, testify, and conduct cross-examinations in formal hearings. Intervenors often have included local interest groups, labor unions, and environmental interest groups. In California, of 72 applications filed with CEC from 1995 through 2001, 39 have had intervenors. In Texas, members of the public meeting certain requirements may request a "contested evidentiary hearing" before an administrative law judge.[15] In these proceedings, parties may present

[15] Until recently, only people with a personal interest could request this type of hearing. However, recently the criteria have broadened to allow more people to participate.

testimony, offer evidence, cross-examine other parties' witnesses, and object to the introduction of evidence. The administrative law judge then makes a recommendation to the permitting agency. Since 1995, 15 of 84 air permit applications in Texas had a request for a contested hearing. Two requests resulted in hearings.

The emergence of substantial local opposition to a new plant is a significant factor in receiving necessary approvals, delaying regulatory decisions in many cases, according to regulators in each of the three states. As a result, developers told us that they look for locations where their project will receive local community support because its economic benefits to the local community outweigh its negative effects, such as increased air pollution. Texas permitting officials told us that communities generally welcome new natural gas-fired power plants because they add to the community's tax base and pose few environmental concerns.

Connecting New Power Plants Is Less Costly and Faster for Developers in Texas Than in the Other Two States

The market rules for connecting a new power plant to the local transmission system (referred to as interconnection) in Texas differs markedly from those in California and Pennsylvania. In Texas, interconnection costs can be significantly lower for developers because consumers directly pay, through a charge on their electricity bills, for upgrades to the electric transmission system that are required with the addition of the new plant. In California and Pennsylvania, under current FERC-approved rules, developers pay for the system upgrades with the expectation that they will recoup these costs through electricity sales. Furthermore, in Texas, developers of new power plants sign standard interconnection agreements that specify the terms and conditions of connecting the new plant to the transmission system, which speeds up the negotiation process; California and Pennsylvania do not have such agreements. In November 2001, FERC requested comments and suggestions from interested parties for developing a standard interconnection agreement.

Interconnection Is Less Expensive for Developers in Texas Than in the Other Two States

Under Texas' restructuring rules, developers building plants must only pay for direct interconnection costs (switchyard, substation improvements, line extension—if applicable). Under these rules, all electricity consumers directly pay for the entire transmission system including the costs to upgrade the system to carry the additional electricity produced at the new power plant. The interconnection of a new plant can affect transmission lines located elsewhere on the system, requiring the system be upgraded. The state made this decision, according to officials at the Texas Public

Utility Commission (PUC), to provide a level playing field on which new power plants can compete against existing plants.

This rule emerged after the Texas PUC found, in assessing competitiveness in the wholesale market,[16] that the financial responsibility for needed transmission system upgrades was not clearly defined. Lack of clear definitions, it concluded, could lead to conflicts and delays, and discourage the development of new privately owned power plants.

The Texas PUC has addressed cost allocation issues through the Electric Reliability Council of Texas (ERCOT) by clarifying the rules for allocating system upgrade costs.[17] Under these rules, PUC allocates the annual cost of the transmission costs including these transmission system upgrades and related maintenance to the entities selling directly to consumers, on the basis of their total electric demand and passes these costs on to consumers through a per-kilowatt-hour fee.[18] As a result of these cost allocation rules, interconnection costs to developers are well defined and known early in the development process.

To connect a power plant project to the transmission system, developers must (1) request an interconnection from ERCOT, (2) pay for two ERCOT studies on the proposed plant's potential impact on the transmission system, and (3) provide a security deposit for any costs incurred by the transmission service provider.[19] ERCOT representatives said that they

[16]Project No. 17555, *Investigation into the Competitiveness of the Wholesale Market.*

[17]In response to concerns raised in the Texas PUC's rulemaking project 18703, changes were adopted to the transmission rule that clarified the cost responsibility of transmission upgrades. The PUC Investigation report stated that these changes and its clear statement of cost responsibility should minimize the potential for the gaming of the interconnection process by market participants, because there is now far less incentive to occupy a place in the interconnection queue merely as insurance against the assessment of the cost of significant transmission upgrades.

[18]The 1999 legislation allowing retail competition authorized river authorities to provide transmission services statewide. Over the next 5 years, the Lower Colorado River Authority, in a public/private venture, plans to add up to $500 million in transmission projects that ERCOT identified as important to support the electricity market in Texas. These costs would be recovered through electricity rates within ERCOT.

[19]The developer's deposit covers the cost of planning, licensing, and constructing any new transmission facilities associated with the requested transmission service. According to ERCOT officials, the deposit ensures that transmission improvements are made for only serious projects and prevents losses resulting from cancellations. The deposit is returned when the new power plant begins to use the requested transmission service.

conduct these studies in the order received and completion times vary depending on the application. Generally, the first screening study is completed within 90 days and the more detailed analysis in another 60 days. Developers said that because they do not pay for transmission upgrades, they can locate plants outside of areas with congested transmission systems, such as Dallas. As a result, power plants in Texas generally have been located outside non-attainment areas. According to Texas PUC and ERCOT officials, substantial upgrades to the transmission system were underway because many new power plants are being located in areas in which the existing transmission system could not adequately transmit the added capacity. PUC officials believe that transmission improvements will lead to improved competition in the long-term and noted that ERCOT has given priority to addressing bottlenecks in the transmission system to ensure that all the markets in the state have access to these new supplies of electricity.

In contrast, developers in Pennsylvania pay for both the transmission system upgrades and the direct interconnection costs. Requiring developers to pay for system upgrades acts as an incentive for proposing plants in locations that do not require substantial transmission system improvements or the addition of new power lines, according to staff at PJM Interconnect, Pennsylvania's transmission system operator. Developers must also pay a deposit for PJM Interconnect to complete interconnection studies—as much as $7.5 million in one case for one of the three studies. PJM Interconnect conducts transmission studies for power plant projects as a group—all proposals received within a specific time period are analyzed together. According to PJM Interconnect staff, they need to study the system impacts of all the applications received to accurately assess the interactive implications of multiple new power plants, even though some of the power plants in several of the groups may never be built.

Similarly, developers in California pay for both the direct interconnection costs and upgrades. However, in California, the local transmission system owner determines the cost of the system upgrades, with limited oversight by California's transmission system operator. To connect to the local system, a developer submits an interconnection request to the transmission system owner and the operator. To assess the work and associated costs for the interconnection, the transmission system owner studies the impact of the proposed plant on the transmission system to identify potential reliability problems. If this study identifies reliability problems, the developer may request the transmission system owner to perform a detailed facilities study to determine the measures needed to mitigate those impacts and to identify their associated costs. Current rules require the power plant developer to pay the costs of the interconnection studies and the system improvements required to mitigate reliability problems.[20] The California transmission operator critiques these studies, primarily by evaluating their assumptions and the role of other plants expected on-line.

Texas Uses a Standard Agreement to Facilitate Interconnection, Unlike California and Pennsylvania

To foster competition and facilitate negotiations, Texas requires developers and the local transmission owners to use a standard interconnection agreement to (1) assign responsibility for paying the costs of any upgrades to the transmission system needed for carrying the new plant's added electricity capacity, (2) allocate ownership interests in these assets, and (3) assign responsibility for liability associated with plant and interconnection facility operations.

In establishing this process, the Texas PUC sought to (1) ensure coordinated planning for transmission systems, (2) eliminate delays in the interconnection process, and (3) remove incentives for the transmission providers to favor their own power plants. The standard interconnection agreement, a contract between the power plant developer and the owner of the local transmission system, includes standard terms and conditions and sets specific deadlines for the local transmission system owner to complete the connection and for the developer to start plant operations. The agreement also provides rights to either party to terminate the agreement if the other fails to meet its deadline. Developers told us that the Texas process is much faster to negotiate because, to the extent that the cost allocations can be determined ahead of time, many issues are removed from the business negotiations. Accordingly, both developers and ERCOT staff said that the use of a standard interconnection agreement has worked well in Texas.

In contrast, in California and Pennsylvania, developers and the local transmission system owner do not use a standard agreement and therefore

[20] California's transmission system operator has filed a request with FERC, referred to as amendment 39, to modify the cost allocation of transmission additions required when interconnecting new power plants, including the treatment of system upgrades. According to California's transmission operator, this amendment would allow developers to choose to pay for some transmission system upgrades that allow a plant's output to reach a specific location. In return, the developer would acquire a financial transmission right for use of specific equipment. FERC has not ruled on the transmission operator's filing.

must negotiate the terms and conditions of the interconnection agreement, which typically adds time to the process.[21] Developers in California said that they have to accommodate differences in interconnection policies among transmission owners. These differences, which can occur because different transmission owners interpret the FERC-approved rules differently, have resulted in interconnection disputes between the transmission owners and developers that create barriers or delays to building new power plants. The developer and the transmission owner can either resolve these disputes or appeal to FERC for resolution, which would add even more time.

PJM Interconnect staff plan to develop a pro forma interconnection agreement because it appears to offer advantages over a lengthy negotiation process. The staff believe that FERC wants the operator of the regional transmission system to sign the agreement, but the staff would prefer to keep the agreements between the developer and the transmission owner, citing concerns about PJM Interconnect's potential liability if FERC requires it to sign. They added that, if required, PJM Interconnect would become a party to the agreement but would need to purchase liability insurance with these costs passed on to consumers.

We found that reaching agreement on interconnection was substantially faster in Texas than in the other two states. Specifically, it took 11 months, on average, in Texas, compared with 28 months in California and 30 months in Pennsylvania.[22]

[21] A standardized format is used in Pennsylvania for plants of less than 40 megawatts.

[22] This analysis measures from the date of application until the interconnection agreement was signed. For Texas, data were available for 16 of 34 projects completed since 1995. For Pennsylvania, data were available for 31 completed projects within PJM Interconnect's control area. PJM Interconnect officials said that the process has improved and now takes 20 months, on average, to reach agreement. For California, we excluded smaller plants approved under CEC's 21-day expedited process, which took 11 months, on average. California's average would be 22 months if these projects were included.

FERC Is Evaluating Options for Developing a Standard Interconnection Agreement

In November 2001, FERC published an Advance Notice of Proposed Rulemaking in the *Federal Register* requesting that affected parties provide suggestions and comments for developing a standard interconnection agreement.[23] FERC noted that it had previously required local transmission system owners to provide non-discriminatory, or comparable, access to transmission service and established standard terms and conditions for the service provided by the transmission system owner. However, this requirement did not directly address power plant interconnections.

In this advance notice, FERC also provided the views of both the independent developers and transmission system owners. According to FERC, developers have asserted that, among other things, (1) the treatment they receive is not comparable to the treatment the transmission provider receives for the power plants it owns, (2) system upgrade costs charged to developers are sometimes not related to the interconnection, and (3) delays and uncertainties occur because the transmission owner's rules do not specify binding commitments and firm deadlines for completion of specific actions. In contrast, FERC reported that transmission owners believe that, among other things, they need minimum financial commitments from developers seeking interconnection to weed out plants that are unlikely to be built. The financial commitments are intended to minimize the number of plants they will have to study so that they can accurately assess how much total generating capacity will be added to the system. Transmission owners also want assurance that consumers in their local transmission system will benefit from, or at least not be burdened by, adding power plants, particularly when a developer seeks to locate a plant in one system that would primarily sell electricity to consumers in an adjacent system.

[23]FERC issued a Notice of Proposed Rulemaking for a standardized interconnection agreement as FERC docket on April 24, 2002, and published the notice in the *Federal Register* on May 2, 2002.

Developers in Restructured Electricity Markets Weigh a Project's Projected Profitability against Risks

Restructured markets change the context for investment by enabling developers to broaden the number of markets they consider and by requiring them to make financial commitments long before they actually build a power plant, according to the developers we interviewed. In this context, they generally propose power plant projects in markets where prices are high enough to expect that plants will be profitable. However, they actually build plants in markets where expected profits outweigh possible risks that could reduce a plant's profitability—such as changes in the state, regional, or national rules for the electricity market.

Restructured Electricity Markets Have Changed the Basis for Investment Decisions

In restructured markets, developers told us, several conditions have changed the basis for their decisions to build or not to build power plants. Restructured markets, unlike regulated markets, require developers to independently assess the need for new power plants and their potential profitability. Restructuring allows them to compare opportunities to build plants across multiple markets—state and regional markets as well as international markets. If they decide that a particular market will not be profitable, they will build elsewhere, according to the developers we spoke with. Furthermore, they propose building power plants at three or more sites for each plant that they actually intend to build. Multiple proposals ensure that at least one site will be ready to receive a turbine and other power plant equipment at a specific date. Uncertainty about market conditions at each site and about whether and when they will obtain the necessary permits and approvals to begin construction dictate this multiple site approach, according to developers. Industry analysts noted that because developers have proposed many more project sites than they intend to build, future market prices are less predictable than they otherwise would be.

These market uncertainties have been further complicated by an increased worldwide demand for turbines and financing, forcing developers to compete for these resources. Specifically, because of the increased demand, developers said they made financial commitments to purchase combustion turbines several years before they expect to receive them in order to ensure that they will have turbines when they need them. These commitments can tie up substantial amounts of capital: large turbines can cost $50 million or more, while even small turbines can cost $16 million. Moreover, in restructured markets, without the regulated market's guarantee that investors will have their loans repaid, developers have to compete for investment capital. Bank executives told us they evaluate each power plant project alongside other potential investments, including power plant projects in other states and countries.

Profit Expectations Drive Developers' Decisions About Where to Propose New Power Plants, as Experiences in California, Pennsylvania, and Texas Illustrate

General market conditions and specific site conditions affect expected profitability, according to developers we interviewed. With respect to general market conditions, they first seek opportunities for new investment by analyzing future electricity prices and—to a lesser extent—opportunities to sell other products.[24] In estimating the prices that new power plants may receive in a restructured market, developers evaluate market signals, including current electricity prices and prices in the forward or futures market.[25] Developers then review information about potential competitors in a given market, including the type and age of existing plants and their estimated production costs, as well as economic growth projections that affect demand increases. Finally, developers estimate the overall profitability of selling electricity in a market by comparing the estimated future electricity prices with the estimated cost to generate electricity, based on fuel cost estimates in the area and other variable production costs.[26] For example, industry analysts told us that while actual production costs will vary, typical fuel costs for a new combined-cycle power plant are about 2.1 cents per kilowatt-hour—substantially less than the 3.7 cents per kilowatt-hour cost of some existing gas-fired power plants.[27]

Once they identify a potentially profitable market, developers told us, they look for suitable power plant sites and evaluate the sites' estimated development costs. For gas-fired combined-cycle power plants, developers prefer locations that are near the intersection of a large natural gas pipeline and high voltage transmission lines and that have access to an

[24]In addition to electricity, a new power plant can sell generating capacity (available for contingencies such as outages or unanticipated increases in demand) and specialized services, such as voltage regulation.

[25]Forward contracts allow buyers and sellers to enter into contracts for electricity to be delivered at a future point in time. Futures contracts allow buyers and sellers to trade future deliveries of electricity.

[26]Experts said that they evaluate only a plant's variable production cost; not its average cost. Properly estimated variable production costs, they said, illustrate the profitability of operating the plant at a point in time and are used in determining which units should operate. Average costs incorporate construction and other previously incurred costs that do not reflect the profitability of operating a plant at a point in time.

[27]Actual plant costs will vary. Heat rate is commonly used as a fuel efficiency measure and refers to the rate at which fuel is converted to electricity in BTUs per unit of electricity output (kilowatt-hours). This estimate is based on natural gas costs of $3 per thousand cubic feet, 6,700 BTU/kilowatt-hours heat rate for a new plant and 12,000 BTU/kilowatt-hours heat rate for an older existing plant.

adequate source of cooling water.[28] Developers analyze each site's potential for receiving state and local regulatory approval and for minimizing construction, interconnection, and operating costs. Developers then seek to acquire the right to develop the property—by either purchasing the land or obtaining an option to purchase the land—and then may begin pursuing regulatory and interconnection approvals for the site.

Market and Regulatory Risks Counterbalance a Site's Potential Profitability

In restructured markets, developers said, they regularly analyze each power plant project's market and regulatory risks to determine whether these risks could significantly reduce expected profitability. Market risks include the possibility that electricity prices will be lower than expected and/or that production costs will be higher than expected. Regulatory risks include the possibility that the rules for the electricity market will change or that the rules governing power plant operations will change.[29] Developers reevaluate market and regulatory risks as the project moves forward to determine whether to continue the project. Higher risk levels can cause developers and commercial banks to delay investment until expected profits outweigh the increased risk, according to developers.

Assessing risk is important, developers said, because a new power plant is expensive to build—costs could exceed $500 million—and operates for 20 years or more. Some developers and commercial banks prefer investment opportunities with lower levels of risk, such as when they can sell a substantial portion of the plant's electricity production through long-term contracts with set prices and terms. Other developers said that they will invest in riskier projects if expected profits are higher.

Developers also told us that regulatory risks, such as lengthy and uncertain state approval processes and stringent environmental compliance requirements, were not, by themselves, obstacles to building a power plant in a state. Rather, they said, these factors can increase a project's risk because it is more costly to build and operate and because long-term projections about market conditions are less reliable. For

[28] In addition to rivers and streams, cooling water sources could include at treatment plant-processed water, known as "gray water," before it is released into surface waters.

[29] Market risk can occur when mild temperatures or lower levels of local economic activity reduce electricity demand and lower prices. Regulatory risk can also occur when regulators intervene to alter electricity market rules by, for example, imposing or removing a price cap.

example, plants subject to more stringent environmental standards need more costly emissions-reduction equipment and have less operating flexibility to respond to changes in demand, according to a turbine manufacturer. Furthermore, limiting a plant's ability to respond to changes in demand can reduce its profitability.

In restructured states, market rules, which set the terms for buying and selling electricity and related products, can affect the potential volatility of electricity prices. For example, prohibiting the use of long-term contracts exposes buyers and sellers to the risk of rapidly fluctuating prices. Alternatively, a state with a price cap could expose power plants to the risk that electricity sales will be unprofitable under certain circumstances.

Given the importance of market rules, developers prefer stable and transparent rules that clearly describe the opportunities and risks inherent in a state's market. They told us that they conduct a detailed analysis of the rules and participants for each market that they may enter because market rules vary. For example, restructuring created some multistate regional markets, while other markets are still dominated by regulated utilities and are subject to substantial state control.

Furthermore, developers said that they prefer rules that provide clear and direct opportunities to manage the risk of volatile electricity market prices. Often, developers can reduce their exposure to this risk by (1) buying natural gas at fixed prices through long-term contracts and/or (2) selling the plant's future output through long-term contracts that generally set a future sales price. Several developers told us that they seek to commit at least 50 percent of a new plant's output to long-term sales contracts. Lenders and staff at investment ratings companies also told us that long-term contracts with financially sound purchasers are important tools to lower risks when financing new power plants. They noted that long-term contracts with fixed prices and terms enable developers to obtain more favorable financing terms because selling a portion of the plant's future output reduces the project's market risk.

While transparent market rules can improve the investment climate for a specific market, some developers were also concerned about whether the rules were consistent and equally enforced. Operators of regional transmission systems, transmission system owners, and federal and state regulators are each responsible for enforcing market rules. Developers said that restructured markets were generally improving their treatment of independent developers. However, some developers were still concerned about the administration of the transmission system and the potential for unequal access to market information in markets where they compete with power plants owned by transmission system owners.

Experiences in Three States Illustrate the Influence of Profitability and Risk Considerations on Decisions to Propose Power Plants

California, Pennsylvania, and Texas, with different market and regulatory environments, illustrate how developers weigh profitability and risk.

Lower Potential Profits and Higher Risks in California Delayed, and May Continue to Delay, Investment

According to electricity industry analysts, profitability and risk considerations in California delayed proposals to build power plants in the state. Developers cited the following profitability concerns before prices began rising dramatically in May 2000: (1) the state required its three largest utilities to use only the short-term electricity market to buy nearly all of the electricity sold to their customers and (2) electricity prices in the short-term markets averaged 2.9 cents per kilowatt hour, which was generally lower than prices in other U.S. markets, and, as a result, offered lower potential profits than in other markets. The market rules limiting the use of long-term contracts in California effectively increased the risk of building power plants in that state.[30] One power plant developer told us that because California did not have a robust and predictable market for long-term electricity sales, it could evaluate only the prices in the short-term electricity market, which exposed the developer to more risk without the expectation of higher profits. However, developers told us that once prices began to rise, they began to propose building more power plants in the state. From May 2000 through June 2001, electricity prices increased fourfold, on average, to 13.4 cents per kilowatt-hour.

In response to the electricity crisis during 2000 and 2001, California took several actions that increased its involvement in its electricity markets. First, in January 2001, the state replaced the governing board of its transmission system operator with members appointed by the Governor. Second, the state created the California Power Authority, which can,

[30] California later revised its market rules to allow utilities to enter into long-term contracts, but only on a very limited basis through the state-operated market and without the California PUC's assurance that utilities would be able to recover their costs.

among other things, finance up to $5 billion for power plants. Senior state officials have said that the electricity market would not be sufficiently competitive until an excess capacity of 15 percent was located in the state and that state financing provided one way to increase in-state generating capacity. However, according to investment analysts and developers, the potential that the state might build up to 15 percent excess generating capacity increases the risk and uncertainty for investing in California's electricity market. Third, California entered into long-term contracts to buy electricity and bought electricity day-to-day in short-term markets because the state's two largest utilities faced severe financial problems and difficulty purchasing electricity.

Taken together, these actions have created concerns among developers about whether the operator of the California transmission system will provide equal treatment for market participants. Specifically, employees for the state agency responsible for buying electricity had access to the transmission system operator's control center and may have had access to real-time data not provided to other market participants, even though the transmission system operator's rules prohibit such treatment for market participants. Audits of the transmission system's operations identified several other violations of the rules. Although FERC ordered state staff to leave the operations room, developers remain concerned that the state may receive special treatment from the transmission operator. This concern continues because the state has so much potential influence over the market, which raises the risk of entering the market for independent developers.

Furthermore, investment analysts told us that some investors are even more cautious about investments that rely on California's electricity markets. The lack of stable market rules presents uncertainty regarding the eventual market in the state. In addition, the perception that the state is seeking to abrogate the long-term contracts it signed last year has raised concerns about the finances of some projects. These analysts explained that, due to the risks in the current market, energy investments in California may require higher returns and/or more stringent loan terms,[31] as well as management of risks through, for example, the use of long-term

[31]Developers may need to invest more equity and less debt to finance new power plants. Developers and investment advisors said that many new projects are being financed as part of multi-plant portfolios and use more rigid loan terms requiring that loans be repaid sooner than scheduled if terms of the loan are not met.

contracts with purchasers other than the state as a basis for obtaining loans.

Pennsylvania and Texas Illustrate How Developers Balance Risks and Profits

In Pennsylvania, developers proposed building relatively few power plants because while the risks were manageable, the profits were too low, according to developers. In addition, the transmission interconnection process was protracted, with uncertainty regarding the capital investment needed to fund transmission upgrades. The market rules have permitted power plant developers to enter into contracts to sell electricity for delivery at a future date. These long-term contracts enable developers to manage their risk by providing fixed prices and terms for electricity sales. However, electricity prices were too low to attract investment. Low-cost existing generating capacity was available because the state's industrial base has declined as many steel plants and other industries that consumed substantial quantities of electricity closed or moved out of state, according to Pennsylvania PUC officials. However, developers said that Pennsylvania has attracted some investment because of its access to other markets such as those in northeastern electricity systems in New York State and New England, which have had relatively high prices.

In Texas, risks were manageable and profits were attractive. As discussed earlier, the market rules in Texas reduced risk through its (1) relatively faster regulatory approval process and (2) interconnection rules, which lowered development costs and simplified the administrative process. In addition, the rules in Texas allowed developers to manage their risk through long-term contracts. Furthermore, developers invested in Texas during the initial operation of its wholesale electricity market because the market appeared to be profitable. The electricity prices and the cost of production at existing plants were relatively high compared with the estimated cost of producing electricity at new plants. While Texas significantly increased its generating capacity, several developers and lenders expressed concern that the Texas market may soon have too much new capacity.

Conclusions

As restructuring broadens electricity markets to span multiple states, states will become more interdependent for a reliable supply of electricity—one state's problems can affect its neighbors. In this context, restructured electricity markets rely on the investment decisions of individual developers. Consequently, the reliability of the electricity system—and the success more generally of restructuring—now hinges on whether these developers choose to enter a market and how quickly they are able to respond to the need for new generation capacity.

Developers decide on which markets to enter by balancing profitability and risk—that is, by considering how the regulatory processes and markets rules affect risk in a market and to a lesser extent, the profitability of building a plant in that market. FERC's decisions on market rules and the states' decisions on regulatory rules can affect the balance of profitability and risk in a state. The experiences of California, Pennsylvania, and Texas show how these considerations have played out. The high levels of perceived risk and low levels of estimated profitability in California appear to have resulted in lower levels of early investment in new power plants in that state. On the other hand, the experience in Texas illustrates that the ability to manage risk and higher levels of estimated profitability combined to attract significant investment into new power plants from 1995 through 2001. The experience in Pennsylvania illustrates that while risk may be manageable, estimated profits also have to be high enough to attract investment.

Developers can be deterred from building a power plant if the market has lengthy delays between making the proposal and selling electricity. These delays increase a developer's uncertainty whether the proposed project will be approved and whether additional costs will be incurred that reduce the plant's profitability. In this context, interconnection agreements are critical in assessing profit and risk. Lengthy negotiations over interconnection terms and conditions can increase the risk of developing a new power plant because forecasts of market conditions in the more distant future are less reliable than near-term forecasts. Texas was able to reduce delays in negotiating these agreements, in part because the Texas PUC's standard agreement already specified many of the parties' responsibilities. In contrast, under rules approved by FERC, California and Pennsylvania allowed developers and transmission system owners to negotiate their responsibilities, which has resulted in a lengthy process—more than twice as long as in Texas. A standard agreement also provides better assurance that transmission owners will treat all developers of new power plants equally. In addition, Texas' rules provided a clear method for allocating costs associated with upgrading the transmission system, which appear to have sped negotiations because the amount and allocation of these costs are not contested.

Recommendations for Executive Action

To facilitate development of power plants needed in restructured markets and to provide comparable treatment for all developers, we recommend that the Chairman of the Federal Energy Regulatory Commission, in consultation with transmission system owners, power plant developers, and lenders, (1) develop and require the use of a standardized interconnection agreement and (2) clarify how transmission system upgrade costs are allocated.

Agency Comments

We provided FERC with a draft of this report for review and comment. The Chairman of FERC agreed with our recommendation, noting that FERC had issued a Notice of Proposed Rulemaking on April 24, 2002, which would require transmission system owners under FERC's jurisdiction to use a standardized interconnection agreement. FERC developed the proposed agreement in consultation with industry participants. (See app. V for FERC's comments.) In addition, FERC provided comments to improve the report's technical accuracy, which we incorporated as appropriate.

As arranged with your offices, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days after the date of this letter. At that time, we will send copies to appropriate congressional committees, the Federal Energy Regulatory Commission, the Director of the Office of Management and Budget, and other interested parties. We will make copies available to others on request.

If you or your staff have any questions about this report, please contact me at (202) 512-3841. Key contributors to this report are listed in appendix VI.

Jim Wells
Director, Natural Resources
and Environment

Appendix I: Scope and Methodology

To compare the electricity needs of California, Pennsylvania, and Texas, we examined reliability reports prepared by the North American Electric Reliability Council and the three regional councils that include most of the area of the states that we studied—the Western System Coordinating Council for California, the Mid Atlantic Area Council for Pennsylvania, and the Electric Reliability Council of Texas (ERCOT) for Texas. To assess the extent to which these states have added new power plants or received proposals to add power plants, we used industry databases from Resource Data International (RDI). We used RDI's PowerDat database to identify new generating units that began operation between 1995 and 2001. RDI obtains data for the PowerDat database from a range of public filings to the Energy Information Administration, the Federal Energy Regulatory Commission, and other entities. We also used RDI's NewGen database to identify proposals to build new power plants, as well as construction, cancellations and postponements of new power plants. RDI obtains data for the NewGen database from various sources, including developers, government agencies, banks, trade journals, and newspapers. Data on proposals may not fully reflect all capacity that has been proposed at a point in time. We did not verify the databases provided by RDI.

To compare the regulatory processes for approving new power plants, we reviewed reports, interviewed officials in the states, and examined data. We reviewed reports prepared by the California State Auditor, the California Energy Commission (CEC), and industry summaries of the permitting process prepared for the Edison Electric Institute, an industry trade association. We visited California, Pennsylvania, and Texas to interview federal and state regulatory and permitting officials to assess (1) each agency's responsibilities; (2) each state's implementation of the Clean Air Act and Clean Water Act, as well as Endangered Species Act; (3) each state's process for public participation; and (4) the amount of time required for approval. The state agencies we interviewed in California included CEC, the Electricity Oversight Board, the Governor's Green Team, and the California Environmental Protection Agency, as well as two regional air quality districts. In Texas, we interviewed officials of the Texas Natural Resource Conservation Commission (TNRCC), which is responsible for issuing permits for air quality and water quality. For Pennsylvania, we interviewed officials at the Pennsylvania Department of Environmental Protection (DEP) and the Delaware River Basin Commission, which manages the Delaware River System, including eastern Pennsylvania. We also interviewed officials at the U.S. Environmental Protection Agency (EPA) and the U.S. Fish and Wildlife Service at their Washington, D.C., headquarters offices and their regional offices in each state.

To calculate the duration of each state's regulatory review process for approved power plants, we compared the time from when each application was deemed administratively complete to the date CEC approved the project in California, TNRCC approved pre-construction air permits in Texas, and the Pennsylvania DEP approved pre-construction air permits in Pennsylvania—the air permit is the primary regulatory process in Texas and Pennsylvania for gas-fired power plants. We compared approved permits from January 1, 1995, to December 31, 2001. To compare the implementation of the Clean Air Act standards for approved permits, we identified the location of the plant (whether in an attainment area or a non-attainment area), the type of permit required, and the emissions limits. To compare the extent of formal public participation prior to permit decisions, we compared the number of requests for contested hearings and the number of contested hearings in Texas with the number of permit applications with intervenors in California for permit applications submitted between January 1, 1995, and December 31, 2001. Pennsylvania's only mechanisms for formal public participation prior to permit decisions are the public notification and comment process and through public hearings.

To compare the processes for connecting new power plants with local electricity transmission systems, we visited each of the three states and interviewed officials at the transmission system operator serving the state: we interviewed officials at the California independent system operator in California; the PJM Interconnect in Pennsylvania; and ERCOT in Texas. In addition, we interviewed officials at one of the California's three major utilities, which play a large role in completing the studies in that state. To determine the amount of time needed to reach an interconnection agreement, we examined data that the three states provided to us. To determine the time that the process took in each state, we examined data provided by (1) owners of transmission lines for plants larger than 50 megawatts in California, (2) PJM Interconnect in Pennsylvania, and (3) ERCOT in Texas. We also met with officials of the Federal Energy Regulatory Commission and the Edison Electric Institute.

To identify the key factors that developers consider in deciding where to propose and build new power plants, we examined reports prepared by industry experts and we met with senior executives of three large and three smaller independent power plant developers to discuss the key elements in their investment decisions. To learn more about the current technologies of power plants being built in the United States and the market for turbines, we interviewed executives of a large manufacturer of turbines and toured a combined-cycle power plant. To identify what factors are important to the financial markets, we interviewed energy market investment analysts of two investment ratings companies serving the financial markets and executives of four investment banks that lend money to power plants developers.

We examined the approval process for building a new natural gas-fueled power plant because these types of plants are the most common plants being proposed in the United States. However, as agreed with your office, we did not address related issues, such as the process for obtaining rights of way for connecting to a nearby natural gas pipeline or the local transmission lines. We conducted our work from August 2001 through April 2002 in accordance with generally accepted government auditing standards.

Appendix II: California's Process for Approving New Power Plant Projects

Before a developer can begin to construct a new power plant project, California's CEC must approve the project, which incorporates all of its required state and local permits. While CEC conducts its review, each project is also reviewed by (1) 1 of 35 regional air districts and 1 of 9 regional water boards, or by EPA's region 9 in some parts of the state, for compliance with air and water quality requirements; (2) local governments for compliance with land use and zoning requirements; and (3) if applicable, state and federal agencies for compliance with the Endangered Species Act. The CEC certification process allows for public participation through the intervenor process, a public advisor, as well as by planned public participation throughout the application review process.

CEC's Certification Process

CEC must certify all power plant projects with a generating capacity of 50 megawatts or more before they can be built and operated. As shown in table 2, CEC has established time frames for each phase of its certification process in order to approve or reject a project within 1 year after a developer's application is deemed "data adequate." While CEC receives information from other state and local agencies, it conducts an independent assessment of each proposed project's environmental impacts; public health and safety; compliance with any applicable local, regional, state and federal laws, ordinances, and regulations; efficiency; and reliability. However, CEC does not assess the need for each proposed new plant. As the lead agency for certification, CEC issues all required state and local permits and is authorized to override the permitting decision of a state or local government agency.

Table 2: CEC's Certification Process

Scheduled time	Phase	Action
6 months to 1 year (possibly more)	Pre-filing (not required)	Applicant meets with CEC and other state agencies (optional) to discuss the certification process, filing requirements, and project-specific issues. Applicant prepares application.
	Filing	Applicant files application with CEC
45 days (longer if application is not deemed complete)	Determination of data adequacy	CEC reviews the application for completeness. If the application is deemed incomplete, CEC requests additional information from the applicant. CEC must determine data adequacy within 30 days after the applicant submits a supplemental filing. Other state and local agencies, including the local Air Board and Water Board, review the application to assess permitting requirements.
120 days	Discovery/data requests	CEC collects any other additional data required from the applicant, agencies, and other relevant sources. CEC holds public workshops on technical and procedural issues and public hearings.
90 days	Analysis	CEC prepares a preliminary staff assessment based on its independent analysis of the application. Public workshops are held on the Preliminary Staff Assessment. CEC issues a final staff assessment, which is the staff's testimony for CEC's hearing phase.
90 days	Public hearings	The applicant, CEC staff, and relevant agencies present testimony to the CEC committee assigned to the application. Intervenors and the public are permitted to testify or provide comments.
65 days	Decision	The CEC committee prepares the presiding member's proposed decision, which is circulated for public review and comment and revised. The full Commission adopts, modifies, or rejects the proposed decision and either approves or denies the application.
Total time: 410 days (excluding pre-filing)		

Note: A power plant application typically consists of (1) the project description; (2) site description; (3) engineering description of proposed facilities; (4) electric transmission lines and any other linear facilities related to the project; (5) project, site, and linear alternatives; (6) environmental description and expected impacts including biological surveys conducted at the appropriate time of year; (7) mitigation measures to reduce potentially significant environmental impacts; (8) information necessary for the local/regional air pollution control district to make a determination of compliance with local rules and regulations; (9) information necessary for the regional water quality control board to issue waste discharge requirements or a national pollution discharge elimination system permit; (10) compliance with applicable laws, ordinances, regulations, and standards; (11) financial impacts and estimated cost of project; and (12) project schedule.

Source: CEC.

In early 2001, in response to the electricity crisis, the Governor of California authorized CEC to replace the process described in table 2 with the following expedited reviews of new power plant projects:

- 21-day process for small power plants that operate only during peak demand periods, provided that the plants could begin operating by September 30, 2001;
- 4-month process for power plants using simple-cycle natural gas turbines that could begin operating by December 31, 2002; and
- 6-month process for combined-cycle and steam power plants, with no adverse environmental impacts, for which applications have been submitted by January 1, 2004.

CEC identified potential sites to minimize the effect of limited environmental reviews and reduced opportunity for public participation. As of December 31, 2001, CEC had approved 11 small power plant projects under the 21-day process, taking 22 days on average; 2 simple-cycle power plant projects under the 4-month process; and 1 combined-cycle power plant project under the 6-month process.

Air Quality Requirements

As part of its EPA-approved plan to implement the Clean Air Act, California has 35 regional air districts responsible for attaining state and federal ambient air quality standards within their regions. Each air district adopts its rules and own permitting process and establishes and enforces air pollution regulations for stationary sources that are at least as stringent as federal requirements and that address the particular air quality problems in its region. As a result, the application process for federal and state air quality permits can vary.

Most of California's densely populated areas are non-attainment areas for ozone. Nitrogen oxides, which combine with other pollutants to form ozone, are emitted by power plants. Building a new power plant in these areas is more costly because the plant must (1) achieve low nitrogen oxide emission levels by adding pollution control devices and (2) offset its nitrogen oxide emissions by acquiring emissions credits. California issues emissions credits when emissions from existing sources are reduced. Power plant developers have found that these credits, which can be traded or sold, are difficult or costly to obtain in many non-attainment areas because of their scarcity. According to CEC officials, the lack of emissions reduction credits for offsetting a new project's emissions could limit the number of new gas-fired power plants in the state.

Water Quality Requirements

As part of its EPA-approved plan to implement the Clean Water Act, California's nine regional water quality control boards are responsible for attaining state and federal water quality standards. Each water board may establish and enforce water pollution regulations that are at least as stringent as federal requirements. As a result, the application process for federal and state water quality permits can vary, making the siting process more complex.

Endangered Species Act

Under the Endangered Species Act, California has the second highest number of endangered or threatened species in the country behind Hawaii, increasing the likelihood that a new power plant project may affect the habitat of a listed species. EPA's region 9, which includes California, routinely notifies the U.S. Fish and Wildlife Service about new power plant projects because it considers air and water quality permits that it, or a delegated district, issues are federal actions that trigger notification under the Endangered Species Act.

Other Local and State Government Reviews

A power plant developer must address any applicable local and state laws, ordinances, regulations, standards, plans and policies as part of its CEC application. Although CEC issues all state and local permits as part of the overall certification, it is legally required to ensure that a proposed project complies with all regulations and laws that would be enforced by any other local or state agencies. Exceptions to this requirement could occur if CEC finds that (1) the project is needed for public convenience and necessity and (2) no more prudent and feasible means of achieving such public convenience and necessity exists.

The power plant application must be tailored specifically to address the project's location. Among other things, the application typically has to address (1) land use and zoning plans, including development restrictions under the California Coastal Act and the Delta Protection Act; (2) public health; (3) worker safety and fire protection; (4) transmission system engineering and safety; (5) traffic and transportation plans and policies; (6) noise; (7) visual considerations; (8) socioeconomic issues, including impacts on local school districts and environmental justice issues; and (9) biological resource protection, including county open space and conservation plans and state law protecting wildlife habitat, endangered species, and native plants.

Intervenors

CEC allows any person to petition to become involved in the certification process for a new power plant project as an intervenor. Government agencies, community groups, interest groups, labor unions, businesses (including applicant's power plant competitors), and individuals can become intervenors.

An intervenor is a full, legal party to the proceedings with the same rights and obligations as other parties in the proceeding, including CEC staff and the applicant. CEC can use evidence provided by intervenors as the basis for any part of its final decision. Intervenors have the right to (1) obtain information from the other parties in the proceeding, (2) receive all documents filed in the case, (3) present evidence and witnesses, and (4) cross-examine the witnesses of the other parties at public hearings. Correspondingly, intervenors have the obligation to send copies of all filings to the other parties, answer data requests from other parties, and allow other parties to cross-examine their witnesses. Intervenors can play an important role in the certification process—as many as 16 intervenors have participated in CEC's consideration of an application; can add a considerable amount of time to the certification process; and can potentially kill a project, according to CEC officials.

Public Involvement

In addition to allowing intervenors, CEC's certification process has a strong public participation component. The Warren-Alquist Act requires that CEC ensure meaningful public participation in power plant certification. CEC has a public advisor, an attorney who serves as an advisor to both the public and CEC to ensure full and adequate public participation. CEC conducts public hearings and workshops at several points in the certification process. Also, the public can submit written comments to CEC about a power plant application.

Appendix III: Pennsylvania's Process for Approving New Power Plant Projects

Pennsylvania has no overall state agency responsible for approving new power plant projects. Power plant developers must work through (1) the Pennsylvania DEP to obtain air quality and water quality permits and (2) local government agencies to obtain zoning and other land use permits. In addition, developers in eastern or central Pennsylvania have to obtain permits from the Delaware River Basin Commission or the Susquehanna River Basin Commission, respectively, for access to river water. Since 1995, the average time needed to obtain a pre-construction air permit for power plant projects was about 14 months.

Air Quality Requirements

EPA has approved Pennsylvania's program for issuing New Source Review air quality permits. Almost all air quality permits are issued by DEP's six regional offices or the County Health Departments in Allegheny (Pittsburgh) and Philadelphia counties, which are DEP authorized air pollution control agencies. DEP has overall approval of the permits prepared by these counties.

For permitting purposes, DEP treats the whole state of Pennsylvania as an ozone non-attainment area because it is an ozone transport region as defined under the Clean Air Act. As a result, new power plant projects must install control technology that meets the lowest achievable emission rate for nitrogen oxides. Improved technology has enabled approved nitrogen oxide emissions levels to drop from 4.5 parts per million to 2.5 parts per million in recent years. New power plant projects also have to offset their nitrogen oxide emissions with emissions reduction credits, which can be obtained from either in-state or out-of-state sources. According to DEP officials, the vast majority of emissions reduction credits have resulted from the shutdown of facilities. DEP keeps an online registry of offsets, but companies typically purchase offsets through brokers at about $10,000 to $12,000 per ton. DEP officials noted that it is more difficult to obtain emission offset credits for use in the severe ozone non-attainment areas of the state.

In 1995, the Governor of Pennsylvania established a "money-back guarantee" permit review program that would return an applicant's fees if DEP did not meet established time frames for issuing environmental permits—1 year for a power plant's air quality permit. (The fee for a new source review permit is $18,000.) The 1-year time frame includes only DEP's review and excludes other agencies' review or the time required to hold a public meeting or hearing. Processing time is calculated from date of application receipt to date of final decision, minus time used by the applicant to correct deficiencies. DEP officials told us that the program was initiated to demonstrate DEP's commitment to timely consideration of permit applications. They noted that missing a final date does not force DEP to approve a permit and added that they have yet to give money back because of delays in issuing a power plant permit.

Water Quality Requirements

In 1978, EPA authorized DEP to administer the National Pollutant Discharge Elimination System (NPDES), which controls discharges of pollutants to surface waters. DEP's six regional offices issue NPDES permits. According to a DEP Water Division official, the time frame for reviewing NPDES permits ranges from 120 to 200 days from application to decision. The Water Division has not had to return money to applicants under the state's money-back guarantee program for permit reviews, according to DEP officials.

DEP's Permit Review Process

DEP's administrative completeness review determines whether all necessary information and forms are provided without assessing an application's technical quality. DEP has 20 days to review an application for completeness and notify the applicant whether the application (1) has been accepted, (2) has minor deficiencies that are identified, or (3) is being returned for being severely deficient. Applicants are given one opportunity to correct any administrative deficiencies.

DEP's preliminary and final technical reviews analyze the proposal for potential adverse environmental impacts; check for completeness, clarity and soundness of engineering proposals; ensure conformance with applicable statutes and regulations; and analyze public comments. If DEP finds technical deficiencies, it outlines the specific problems that must be corrected, citing the statutory or regulatory authority that provides the basis for the deficiency. If the applicant fails to respond within a reasonable period of time, the applicant waives all rights under DEP's money-back guarantee program. If the material submitted in response to the deficiency letter still fails to meet DEP requirements, DEP sends a second, pre-denial letter. This letter allows the applicant a last opportunity to correct the remaining technical deficiencies. DEP will deny the application if the applicant fails to address the deficiencies. Alternatively, instead of responding to a deficiency letter, the applicant has the option of asking DEP to make a decision based on the available information. If DEP denies the application, the applicant may appeal the decision or file a new application.

DEP renders a final decision on the application based on its assessment of the technical information, including consideration of reviews required by other federal or state agencies. Either the applicant or the public may appeal this decision to the Pennsylvania Environmental Hearing Board, and the Environmental Hearing Board's decisions may be appealed to the Pennsylvania Commonwealth Court.

Public Involvement in DEP's Permit Review Process

Pennsylvania requires opportunities for public participation in DEP's permitting process through written comments, public meetings, and public hearings. DEP may also invite additional public participation at its discretion. DEP provides opportunities for public involvement by (1) making available a copy of the permit application, emissions data, and other information related to a permit application; (2) receiving comments and answering questions at public meetings; (3) in many cases, holding a hearing to document public concerns as an official part of the public notice process; and (4) soliciting written comments from the general public on its draft permit. The need for a hearing depends on the quantity and nature of comments—DEP typically holds a hearing for large power plant projects or for projects with a lot of public opposition. DEP considers both solicited and unsolicited comments in reviewing a permit application. DEP makes its draft permit available for public review and comment and considers revisions to the permit based on the comments received. Concurrent with public review and comment, DEP also sends the draft permit to EPA for its review and comment in accordance with applicable state and federal requirements.

Although members of the public can participate in DEP's public hearings, they cannot intervene in the administrative appeal process until the permit has been issued. After a permit has been issued, the permittee or the public can appeal the issuance of the permit to the Environmental Hearing Board.

Water Use Requirements

If a power plant proposed for the eastern or central part of Pennsylvania would withdraw more than 100,000 gallons of water a day from a river basin for operations, the developer must obtain permit approval from the Delaware River Basin Commission or the Susquehanna River Basin Commission. The Delaware River Basin Commission's review of a water use application in eastern Pennsylvania often takes between 6 months and 1 year, according to commission officials. Developers can apply for a permit while their other permit applications are being considered. However, the commission cannot issue a permit until DEP has issued all water quality permits. Commission officials said that processing the permit usually takes about 60 days once DEP has issued the water permits.

Endangered Species Act

Three Pennsylvania state agencies are responsible for protecting endangered and threatened species: (1) the Fish and Boat Commission is responsible for fish, other aquatic organisms, reptiles, and amphibians; (2) the Game Commission is responsible for birds and mammals, including 14 endangered species; and (3) the Department of Conservation and Natural Resources is responsible for native wild plants. The Department of Conservation and Natural Resources maintains the Pennsylvania Natural Diversity Inventory, which includes all of the department's lists of where threatened and endangered species, critical habitats, and areas of critical dependence are known to occur. The U.S. Fish and Wildlife Service and Pennsylvania's Fish and Boat Commission provide DEP with additional listings of species and habitat ranges.

Permit applicants are required to (1) conduct a database search of the Pennsylvania Natural Diversity Inventory to determine the potential presence of a listed species in the vicinity of the permit application area and (2) check any other readily available sources provided by the natural resource agencies. If the applicant finds that the project might affect a habitat area, the applicant is responsible for contacting the responsible natural resource agency. The agency then provides advice about species presence, critical habitat, and critical dependence issues. If the activity may harm the species, the applicant must work with the natural resource agency to conduct surveys, modify the project, or devise any other relevant actions to protect the species and its critical habitat.

An applicant submitting its permit application to DEP must provide proof of coordination. Alternatively, the applicant must provide documentation if no habitats for listed species were found in the affected area. In addition, the public may identify threatened or endangered species issues not previously addressed when DEP made the draft permit available for comment. Pennsylvania does not consider the air and water quality permits to be federal actions that trigger notification of the U.S. Fish and Wildlife Service. While DEP does not specifically consult with the U.S. Fish and Wildlife Service about individual permit applications, the Fish and Wildlife Service may provide comments during the comment period.

Appendix IV: Texas' Process for Approving New Power Plant Projects

TNRCC is responsible for approving environmental permits in Texas. TNRCC must issue air and water quality permits to an applicant that has demonstrated compliance with federal and state requirements.

Air Quality Requirements

EPA has delegated responsibility for approving air quality permits to TNRCC, which has 16 regional offices throughout the state. All air pollution sources are required to obtain an operating permit, unless they are a "grandfathered" facility in existence on the effective date of the Texas New Source permit program in 1971 and have not increased the emissions of any air pollutant. TNRCC's Air Permits Division conducts a new source review of all major industrial projects—in both non-attainment and attainment areas.

The extent of and time frame for TNRCC's review depend on (1) the ambient air quality around the proposed project, (2) whether the project is a major or minor source of emissions, and (3) the amount and type of public participation. The Dallas-Fort Worth, Houston-Galveston, Beaumont-Port Arthur and El Paso metropolitan areas are non-attainment areas in Texas. If a project is in a non-attainment area and emits more than federally defined levels of the relevant pollutant, TNRCC must consult with EPA's region 6 and the developer typically would have to install advanced emission control technologies and purchase emissions credits to offset added pollution. A proposed power plant project in an attainment area generally would qualify for minor source permitting if it emits less than the federally defined level of any criteria pollutant. Alternatively, if the proposed project is in an attainment area and emits more than federally defined levels of the relevant pollutant, it would have to comply with a "prevention of significant deterioration" permit. TNRCC generally approves an air quality permit within 6 to 9 months and an amendment to a permit within 4 to 6 months.

To comply with a prevention of significant deterioration permit, applicants reduce pollutant emissions using best available control technology—developers generally use selective catalytic reduction technology to reduce nitrogen oxide pollution. TNRCC recommends nitrogen oxide limits of 5 parts per million as best available control technology for natural gas-fired combined-cycle operations. TNRCC staff told us that Texas uses "not to exceed" emissions limits based upon a 1-hour averaging time period. For example, to meet very low emissions limits, some applicants seek to average emissions levels over a longer period—which can range from 1 hour to 30 days. The longer period provides a buffer for the plant's actual operations—certain conditions, such as startup and cycling, force emissions higher over a short period. TNRCC also does not recommend lower nitrogen oxide limits because reduction controls involve trade offs with increased ammonia slip, a contaminant under the Texas Clean Air Act. TNRCC's recommended carbon monoxide limits range from 9 to 25 parts per million as best available control technology for all gas-fired turbines.

Water Quality Requirements

TNRCC is responsible for issuing water quality permits under the Clean Water Act. TNRCC's Water Quality and Water Supply Divisions are responsible for the quality, quantity, and availability of water in Texas. In 1998, EPA authorized TNRCC to administer certain permitting processes under the Texas Pollutant Discharge Elimination System, instead of EPA's National Pollutant Discharge Elimination Program. TNRCC staff said it takes about 9 months to 1 year to obtain a water permit.

TNRCC's Permit Review Process

TNRCC staff assist developers in preparing applications by providing pre-application consultations and guidance documents. TNRCC's permits and modeling groups consult with developers about 3 months before the application is submitted. Once it receives a permit application, TNRCC reviews it for administrative completeness. If the application is incomplete and additional information is necessary, this review takes about 30 days. Once it considers an application as complete, TNRCC requires the developer to (1) notify the public of the project by publishing notices in local newspapers and posting a sign at the proposed site and (2) perform air dispersion modeling for all emission sources using EPA-approved computer-based mathematical models. TNRCC staff audit the modeling and evaluate the resulting predicted off-property impacts. TNRCC generally completes its technical review and prepares a draft permit within 90 days and mails the draft permit to the applicant for comment and negotiation, which takes about 30 days. Local and county officials, federal officials, and other interested persons then receive a second public notice announcing the draft permit and providing a 30-day comment period. TNRCC sends each draft permit to EPA. EPA has 30 days to provide comments, although it may ask for an additional time to address comments it receives from the public.

Contested Case Hearings

In addition to giving members of the public the opportunity to submit written or oral comments about a proposed project, Texas allows individuals who oppose an application and who meet certain requirements to request to participate in a contested evidentiary hearing before an administrative law judge.[1] In such hearings, parties have the right, for example, to present testimony, offer evidence, cross-examine other parties' witnesses, object to the introduction of evidence, and file legal motions. The administrative law judge issues a formal recommendation to the TNRCC commission, which issues a final decision. TNRCC officials told us that a contested permit application could add from 1 to 3 years to the project. Since 1995, 15 of 84 air permit applications in Texas had requests for contested hearings. Two requests resulted in hearings, and three requests were denied a hearing. Of the remaining requests, seven were withdrawn, one was pending, and two were relocated.

Public Involvement

TNRCC makes its draft permit available for public comment for a 30-day period by providing notice in a widely read local newspaper and directly notifying the local mayor and other local government officials, the county judge, EPA, the U.S. Fish and Wildlife Service, the Advisory Council on Historical Preservation, the Texas Historical Commission, and the Texas Parks and Wildlife Department. If TNRCC receives a request for a hearing, it determines whether it should hold a hearing, which it does generally about 30 days after the request. TNRCC may adopt the proposed permit, adopt the proposed permit with changes, or deny the permit application. Appeals may be filed with TNRCC once it makes a final decision on permit issuance.

Water Use Requirements

Texas requires a water rights permit for the use of state surface water. TNRCC typically approves a permit for water rights in from 9 months to 1 year for an uncontested application. Each application for a permit is reviewed for administrative completeness; applicants have 30 days to respond if the application is deficient. The technical review, which may take 180 days, evaluates impact on other water rights, bays and estuaries, conservation, and water availability through modeling. Once the administrative process is complete, TNRCC provides notice to the public and gives other water rights holders the opportunity for a hearing. Permits may be issued in perpetuity, for a limited number of years, or for temporary uses.

[1] An individual must demonstrate a personal interest within TNRCC's authority and jurisdiction that could be affected by the application.

Because of increasing water demands for municipal, industrial, and other uses, TNRCC grants new water rights only where normal flows and levels are sufficient to meet demand. As a result, some power plant developers have looked for alternative options to meet their water needs. For example, a company recently negotiated a contract to obtain surface water from a nearby city. When the city submitted an application to amend its water rights permit, opponents to the sale asked for hearings to contest the permit. The company then decided to use another city's existing water right and effluent for the power plant cooling towers. In another case, a company purchased the water rights from another holder to appropriate water from the Colorado River instead of applying for new water rights permit. The ownership transfer was completed in 30 days. An application to amend the water rights to include industrial use was completed 3 months later.

Endangered Species Act

The Texas Pollutant Discharge Elimination System requires that permits and water quality standards protect the environment, including habitats for endangered and threatened species. Texas does not consider the air and water quality permits to be federal actions that trigger notification of the U.S. Fish and Wildlife Service. However, if the Endangered Species Act is a concern for a permit, TNRCC notifies the U.S. Fish and Wildlife Service, the National Marine Fisheries Service, and the Texas Parks and Wildlife Department and asks for their comments. According to TNRCC officials, an Endangered Species Act concern also automatically triggers EPA oversight under the Memorandum of Agreement between TNRCC and EPA.

Local Government Reviews

Before the permit application is submitted to TNRCC, the applicant usually visits the community where it plans to locate the power plant to determine if the local government and community will support or oppose the power plant project. The applicant is responsible for ensuring that the proposed site is properly zoned, or can be rezoned within acceptable time frames. Most communities generally have welcomed gas-fired power plants because they provide a large tax base for the communities and pose few environmental concerns. Similarly, environmental groups have not opposed power plants because natural gas is a low-pollution fuel.

Appendix V: Comments from the Federal Energy Regulatory Commission

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

May 3, 2002

Mr. Jim Wells
Director, Natural Resources and Environment
United States General Accounting Office
Room 2T23
441 G Street, NW
Washington, DC 20548

Dear Mr. Wells:

Thank you for your letter of April 23, 2002, enclosing your draft report, *Restructured Electricity Markets: Three States' Experience in Adding Generating Capacity*. I congratulate you on your effort and appreciate the opportunity to comment on this report.

I wholeheartedly agree with the report's recommendation that the Commission develop and require the use of a standardized interconnection agreement and clarify how transmission system upgrade costs are to be allocated. As I am sure you are aware, we took an important step to do so on April 24, by issuing a Notice of Proposed Rulemaking (NOPR) in Docket No. RM02-01-000, which would require that interconnection service be provided by jurisdictional transmission providers under a standardized interconnection procedure and agreement. The proposed interconnection agreement was developed, in large part, through a collaborative process with industry participants, including generators, transmission providers, and load serving entities.

The interconnection proposal seeks to ensure that transmission providers show no preference for interconnecting their own generators over proposals by other market participants. Although the proposal reflects the Commission's current transmission pricing policies, it invites recommendations for how final transmission expansion and upgrade costs should be allocated. Once finalized, the new interconnection agreement and procedures will supplement existing and future jurisdictional open access transmission tariffs. It will also be used by any non-public utility that wants transmission service from a jurisdictional utility, under existing reciprocity obligations.

While I believe that standard interconnection rules will greatly facilitate new infrastructure development, I would like to emphasize that many other factors affect successful generation development, as your report notes. To that end, this Commission is

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working on two additional institutional elements that should do much to improve certainty and reduce the risk of generation development. The implementation of independent Regional Transmission Organizations, to operate and manage large inter-state transmission systems and wholesale power markets, will do much to assure true open, non-discriminatory access to the grid and safe, reliable, low-cost grid operations. In parallel, the development of Standard Market Design – a common market architecture and set of operating rules for all wholesale market participants in the Eastern and Western interconnections – will accelerate the effective operation of wholesale energy markets with uniform rules and low transactions costs across the nation. Both of these initiatives should come to fruition, through a series of regulatory cases and rulemakings, by the end of 2002. We are confident that the combination of standardized interconnection, standard market design and RTOs will do much to reduce the risks and enhance the appeal of new investment in power plants, transmission lines, and demand response; these in turn will improve competition, lower costs and improve the reliability of America's wholesale power markets.

I appreciate the hard work your staff put into this report and am hopeful it will further the understanding of the power supply problems in California and the West. Thank you again for this opportunity to comment on your report.

Best wishes,

Pat Wood, III
Chairman

Appendix VI: GAO Contacts and Staff Acknowledgments

GAO Contacts

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Richard Cheston (202) 512-3841

Acknowledgments

In addition to those named above, Jon Ludwigson, Ilga Semeiks, Frank Rusco, Carol Herrnstadt Shulman, Leigh White, and Cleo Zapata made key contributions to this report.

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