NATIONAL COUNCIL
ON ELECTRICITY POLICY

STATE POLICIES FOR FINANCING ELECTRICITY RESOURCES

Volume I: Paying For Power Plants In Restructured States

February 2007

CONTENTS

Introduction

Regulated, “vertically integrated” utilities provided electricity to the majority of consumers in the United States throughout most of the 20th century. However, policies enacted to create an opportunity for retail competition and new entrants to the utility dominated market initiated a dramatic change that led many states to re-think the regulation of electricity prices. Some states sought to restructure or deregulate their electricity sectors to allow consumers to choose their electricity suppliers. Under retail choice (also referred to as “retail access” or “retail competition”), the role of the regulated utility was envisioned to be limited to that of a wires company, responsible for the transport of electricity and the owner of the distribution system. For a designated transition period, utilities would also provide “default” electricity supplies for those customers that did not select an alternative provider. But this service would be temporary, assuming all customers would eventually participate in an active, competitive electricity market.

In some instances regional electricity markets have evolved with both regulated and restructured states operating within one competitive wholesale market under the umbrella of a regional transmission organization. The way in which new generation resources are procured or developed varies as much by state as it does by region. The electricity sector has evolved into a complicated system with risks and uncertainties unimaginable just ten years ago. This paper attempts to describe the current system as it relates specifically to the development of new generation resources in regions characterized as restructured and looks to the future of state policy, regulation, and planning to see how and who will pay for the next iteration of existing and emerging power technologies in restructured states. This document offers policy options for State decision-makers in restructured states that may serve as a resource for encouraging the building of new electricity infrastructure when it is needed.

What’s the problem?

In North America, electricity comes to customers over a complex network of power plants, transmission lines, substations, and distribution systems that manage and route power from its generation to its consumption. Most of the time, the power system delivers just as it should—reliably and, until recently, at a generally stable and reasonable cost. Historically, electric utilities owned the power plants, transmission system, and supportive infrastructure. Utilities would recover their capital and operating costs through electric bills paid by their ratepayer customers as approved by the state public utility commission. This “cost-of-service” system made paying for new power plants more straightforward. Their income would be based on the cost of providing service and investing in facilities that would provide new service, at rates approved by a Public Utility Commission - although some would argue that this regulated system also stifled the development of new technologies and created inefficiencies within the system.

In an effort to create opportunities for new market participants and new technologies, the Federal government took action to deregulate wholesale electricity markets, creating what was envisioned as a more competitive and dynamic electricity market. Following the lead of the Federal government, new regulatory frameworks emerged in 19 states and the District of Columbia creating opportunities for a competitive market in the retail electricity sector. Under this new regulatory framework, some states' electric utilities were required to sell off their power plants or spin them off into separate, non-regulated, entities. Without their generators, these utilities became known as "Load Serving Entities," though for the purposes of simplicity in this paper, we will still call them "utilities." They moved from owning the power plants to buying power from a wholesale market, becoming transmission and distribution companies and remaining regulated. Depending on the specifics of the state restructuring laws, the requirement of separate ownership of generation and transmission and distribution (T&D) often led to the divestiture of generation assets by an investor-owned utility. Subsequently, this led to a situation where utilities had to purchase electricity on behalf of any of their customers who did not select an alternative electricity supplier. The cost of providing this "default" electricity service to customers that did not choose to go to another supplier in the retail electricity market was passed back to all of these consumers, as approved by the Public Utility Commissions. Some of the architects of the competitive retail electricity markets envisioned that eventually all customers would participate in the electricity markets and that ultimately the responsibility of the regulated utilities would be limited to that of a "wires" company transporting other people's electricity.

As a result of this unbundling of generation and transmission, utilities in the restructured states were no longer responsible for building new generation. Furthermore, in many cases utilities were not encouraged, or allowed, to enter into long term electricity supply contracts with private developers since their role as a provider of electricity service was envisioned as a short-term, transitional, function. Under this new system, the development of new generation assets required private capital investment unaffiliated with utilities or the supply of electricity to retail customers served by regulated utilities.

Owners of electricity generator assets raised questions about how companies looking to invest in new facilities would recover costs for those investments. Instead of receiving guaranteed cost recovery at a predetermined rate of return, investors now look to market signals to determine how best to invest their capital

In addition to the elimination of cost-recovery, restructured states have also created an environment that is not always favorable to long-term power purchase agreements. Commission-required procurement practices, customer switching, and the regulatory uncertainty inherent in a transition period have increased the risks to prospective developers for those states and regions that have undertaken electricity restructuring. Along with greater risk, investors require a greater return. Hence, the market price signals have to offer a higher potential return than the returns seen in the relatively low risk, regulated environment. However, the higher returns have not materialized to the point where developers and financiers are investing sufficient capital in electricity markets. This raises the question and concern that electricity prices may need to be higher than current market rates in order to generate interest among investors.

The current state of electricity markets leaves regulators and policy-makers with a long list of difficult questions, some of which might include:

1. How do policymakers create an atmosphere in which new generation and new technologies—such as the most modern and cleanest coal fired power plants—will be built? Such technologies often come at a higher capital cost than conventional technologies and are unproven on a large scale. These elements add even more risk to prospective projects and arguably require an even greater return than the conventional projects.
2. How can policymakers balance regulation and open markets to produce a reliable, environmentally friendly power system that operates at a reasonable cost?

To date, there is no road map for success or one-size-fits-all policy solution that will answer these questions. However, the debate regarding policies and incentives to encourage new generation has begun and policy-makers should be informed of the issues and challenges facing the participants in electricity markets., This document provides an overview of how electricity infrastructure might be financed using conventional mechanisms. Furthermore, it identifies some of the problems confronting developers in order to illustrate the key challenges to building new power plants in restructured states. With this information policy makers might better understand the issues surrounding the lack of investment in electricity generation facilities and will be better prepared to discuss possible solutions with regulators, legislators, governors' staff, energy officials, and market participants.

Markets, Jurisdiction, and Regulation: the Vocabulary of Restructuring

The previous section described the problem, but as with most problems, the devil is in the details. This section will explain many of the terms used in the previous section that complicate the problem of financing power plants in restructured states.

Retail vs. Wholesale

The previous section introduced wholesale and retail electric power markets and the regulation of each of those two markets. But what is a "wholesale" transaction, and how is it different from a "retail" transaction? A utility (as is noted above, what is sometimes called a "Load-Serving Entity") or a power marketer sells to homeowners, factories and other power users in the retail market. Wholesale sales typically go from an independent[1] generator to an independent power marketer or electricity supplier, from an independent generator to a utility or from a utility to another utility. The utility or independent power marketer that buys power at wholesale has the option to sell it to someone else on the wholesale market or to sell it to a retail customer. These types of transactions represent the majority of transactions in the wholesale power market.

Federal vs. State Jurisdiction

Complicating matters is the fact that States do not wield total authority over the electricity system. In general, state governments wield authority over retail electricity transactions[2] and electricity distribution systems. The Federal Energy Regulatory Commission (FERC) wields jurisdiction over the wholesale electricity transmission system and the transactions between generators and transmission owners. FERC does not regulate the price of electricity on wholesale markets other than to watch for the abuse of market power and to regulate the system operators to be sure price clearing mechanisms are functioning without prejudice. FERC maintains this authority over wholesale markets because, for the most part, the wholesale transactions occur in interstate commerce as part of an extensive transmission system. FERC wields only limited authority in most of Texas, Alaska and Hawaii because utility grids in these states do not interconnect to grids in other states.

Under FERC jurisdiction, utilities must provide nondiscriminatory open access transmission services to all power generators and wholesale electricity

[1] The term "independent" in all of these situations refers to a company that is not a regulated utility. It could be totally independent of a utility company or it could be a non-regulated sister company or affiliate of a utility.

[2] In states that have deregulated their retail markets to allow for competition among those providing electricity to retail customers, even this authority can be limited.

customers. This means that a transmission owner must let any company use its power lines to send power from one location to another at fair and reasonable rates. These rules work to ensure that all power generators have equal access to any available customers on the power grid in order to sell their power into the wholesale power market.

Regulated vs. Restructured

What is a "restructured" market? Parts of the country— the Northeast, the Mid-Atlantic, most of the Midwest, Texas and California—have moved toward a model that attempts to harness competitive forces for their retail power markets. In the rest of the states in the country, the utilities that operate the power system are under a traditional regulated model. One significant difference between the two models is that utilities in the restructured states have sold off most of their power plants to independent power generation companies, while in traditionally regulated markets, the utilities remain vertically integrated[3]. Another difference is that a handful of the restructured states have allowed companies other than the utilities to sell power to retail customers. In theory, this move to retail competition was meant to remove utilities from the retail electric sales business. In practice, few non-utility retail providers have succeeded in making a business of selling power to retail customers. As a result the same utilities that have delivered power to their customers for many years are still in the business of procuring power for the vast majority of these customers, and these customers continue to receive electricity from regulated utilities under some type of default service provided as part of the transition.

Almost all restructured states and even some regulated states obtain transmission service from Regional Transmission Organizations (RTOs).[4] These RTOs have become common in the eastern part of the country, and operate in the Midwest, Texas and California, with more limited geographical presence in the Southeast and Southwest. RTOs are under consideration in the Rocky Mountain West and Pacific Northwest but do not currently operate there. The RTOs often operate wholesale power market structures. They set and ask FERC to approve rules for transmitting power, allocating costs of building new transmission lines, allowing new power plants on the power grid and maintaining a competitive and reliable power system at the wholesale level. Almost all the activities of RTOs fall under FERC jurisdiction, although state regulators have organized structures that provide input and guidance in their decisions.

---

[3] These are the two most common models. Public power utilities and rural cooperatives are common in many parts of the country, are largely self-regulating, and may or may not participate in regional organizations. Two states—Vermont and Wisconsin—have entirely or largely separated the transmission business from the generation business by forming independent transmission entities. The Vermont Electric Power Company was formed in 1956, and Wisconsin's American Transmission Company in 2001.

[4] A Regional Transmission Organization is an independent organization, typically with board members from many segments of the electric industry (power generators, transmission line owners, distribution utilities, for example). Among many other functions, it develops transmission plans, provides transmission service and operates energy markets.

Why, in some restructured states, were utilities encouraged to sell off (divest) some or all of their major power plants? One of the motivators for this action in states that considered retail competition was a concern that it would be difficult to bring market forces into wholesale power markets if the same company owned and operated both the transmission lines and power plants. Their concern was that it would be easy for the transmission division of a company to give preferential power line access to its sister generating company while discriminating against other generating companies that are their competitors. Some also felt they could address this problem by transferring control of the transmission system to RTOs.

Slightly more than half the states retained the traditional cost-of-service regulated structure, with utilities that are vertically integrated[5]: they own their power plants and transmission lines and serve their retail customers under rates regulated by the state Public Utility Commission. In regulated markets, state commissions have a choice about whether to require their utilities to build and operate their own plants to generate power (transactions that fall under state jurisdiction) or to buy power from independent generators (wholesale transactions that fall under FERC jurisdiction). Notwithstanding vertical integration and apart from state decisions about whether or not to allow retail competition, FERC requires utility companies to "functionally separate" their transmission and generation business. This means that the utilities generally operate the two sides of the business as separate concerns, with strict rules about how much they can communicate with one another. This functional separation is designed to prevent collusion between the generator and transmitter of power, even if they work for the same parent company. State governments oversee utilities' generation business in these states in which utilities have not sold off their power plants.

Just because a utility in a state has restructured the market for sales of electric generation to utilities that can transmit this power to consumers does not always mean that it allows multiple entities to market electricity at the retail level to residential, commercial, or other markets. In states that have allowed competitors to enter the retail market to sell electricity to end users, independent power marketers compete with one another for customers' electricity business – meaning that customers would have a choice of electricity providers much like they have for some years had a choice of long distance telephone providers. The decision about whether to open markets to retail competition is highly controversial, and is separate from the set of decisions about the extent to which utilities can purchase electricity from the wholesale power market. The choice about whether to allow retail competition is a state choice, while oversight of wholesale markets falls under federal jurisdiction.

[5] Vertical integration refers to ownership of all phases of generating, transmitting, distributing power.

Energy, Capacity, and Ancillary Services Markets & Renewable Energy Credits

Power generators in states that have restructured their electric industry earn money from three main payment streams: energy markets, ancillary services markets and capacity markets.[6] In addition, renewable energy producers can earn money from a Renewable Energy Credit (REC) Market in some regions. Keep in mind that the remainder of this section focuses on restructured markets, even though RECs exist in both regulated and restructured states.

Energy Markets in Restructured States

Electricity generators earn money in the wholesale markets based on their sales of kilowatt-hours. More specifically, in restructured states generators make money in energy markets for the kilowatt-hours they sell to utilities and other customers. In general, the more energy that power generators sell, the more money they earn; although circumstances occasionally have allowed generators to manipulate prices by withholding generation from the market, forcing up prices for their remaining generation and capacity. The majority of energy is traded in the form of bilateral contracts—contracts between a generator and a retail power supplier: a utility, a power marketer, or other load-serving entity.

A small percentage of energy also is traded in short-term spot markets—markets that do not rely on long-term contracts but that can set new prices as often as every few minutes. Since spot market prices are volatile, utilities that rely heavily on the spot market for their supply may see more price volatility. It is highly unusual for a utility operating in a restructured market today to rely heavily on the spot market; the example of extraordinarily high and volatile prices that resulted from heavy reliance on spot markets in California throughout 2000-2001 is still fresh. Instead, these utilities rely on the less volatile, long-term contracts for their supply. Spot markets are essential to the operation of the power system, however, since they allow companies to make last-minute adjustments to balance their supply and demand requirements.

What is a "regulated" market? Oftentimes these decisions are made within the context of a resource plan that outlines the projected electricity needs of the designated area along with a plan for how these electricity resources will be provided. Once approved by the appropriate utility commission, the utility would then develop the approved resources, receiving full cost recovery and a designated return on investment as part of a bundled, regulated, electricity rate. Once a resource need is identified a state might require their utility to compete against non-utility energy companies or developers to ensure that the resources needs are met with the lowest cost resource available. A critical difference between the regulated and deregulated state is this ability to require a utility to both plan for and construct new generation facilities as needed. Restructured states no longer have this centralized planning authority.

[6] This does not include additional revenue that may be available to renewable or specialized generators, such as renewable energy credits, tipping fees, etc.

Most utilities rely on a portfolio of contracts for the energy supply that they do not generate themselves. These portfolios would have a mixture of short-, long- and mid-term contracts of six months, one year, two years or three years. The portfolio of contracts should reduce the risk to utilities and to their ratepayers. Utilities also fill in the short-term, day-to-day or hour-to-hour gaps with spot market power purchases and sales. In some cases, longer-term contracts of 10 years or more also may exist. The long-term 20- or 30-year contracts seen in the 1980s and early 1990s are less common today in many areas. This development may make electricity prices somewhat more volatile; because there is no 20- or 30-year price guarantee, prices fluctuate more in the short-term market.

Ancillary Services Markets

The ancillary services markets pay power generators for a series of other services that they deliver to the power grid—for instance, voltage support or reserves—that keep the power grid running reliably. In general, these services maintain the ability of power lines to carry power and allow the power system to respond quickly to small changes in demand.

These services were first established as distinct "products" after FERC issued Order 888 in the mid-1990s — Order 888 was the FERC's first major order that began its own efforts to restructure wholesale power markets. The ancillary service markets are a relatively new innovation, although ancillary services themselves have been in existence as long as the transmission system, bundled together as part of the traditional utility's provision of bulk power.

Ancillary services fall into several categories that vary from one region to another. Those that generators provide are services that help keep the grid running reliably when the supply or demand for power fluctuates on a minute-by-minute basis; a steel mill's demand might vary by tens of megawatts during a single hour, for instance. This ancillary service is known as regulation. Regulation provides quick response to load and supply variations by moving the output of selected generators up and down via an automatic control signal, called automatic-generation control (AGC). These units track the moment-to-moment fluctuations in customers' load and the unintended fluctuations in the output of other power plants. Power generators that have the proper equipment, are connected to the grid, and are in or close to the control area in question can provide this regulation service.

Other such ancillary service payments and markets include spinning reserve, which is defined as generation that can begin delivering electricity into the electric grid with as little 10 minutes' notice. The spinning reserve market is typically only a small portion of the total system's capacity, although it is tremendously important to keeping the power system operating reliably. In PJM (the power region that stretches from Pennsylvania to parts of Illinois), for instance, the spinning reserve market averaged about 250 MW in 2002 out of a system that, at the time, measured in the tens of thousands of MW capacity (it has since expanded to more than 150,000 MW). The average cost for these reserves in 2002 was $19.65 per megawatt-hour. This translated into an annual spinning reserve cost of $42 million.

A review of payments for ancillary services reveals that they vary widely from one company to another and over time. These variation may tend to make the markets unpredictable in some cases, and, although conceptually they could play an important role as a revenue source and as a means to ensure that the ancillary services continue to be provided, they have not historically been a large enough source of revenue by themselves to stimulate construction of new power plants.

Conventional financing requires developers to balance the costs of building a new facility with the expected revenues, plus an additional amount for earning a return for both debt and equity investors. State and Federal policies creating incentives for new technologies also provide a combination of tax credits or revenue streams (e.g., renewable energy credits), for renewable technologies, clean coal installations, nuclear facilities and a number of other designated technologies.

Capacity Markets in Restructured States

Capacity markets pay power generators to be available to generate whether or not they actually do generate. Capacity markets are new and, in some ways, more difficult to understand than the more straightforward energy markets. These capacity markets are meant to be a market-based partial substitute for required reserve margins that existed under the more regulated system. Reserve margins represent a safety margin of generating capacity above the peak demand that the industry would ordinarily expect to need in an average year. The reserve margins in the regulated system mandated that each utility be able to generate an administratively determined amount of power in excess of its expected peak demand. A utility that expected its demand to peak at 1,000 megawatts would need to maintain 1,150 megawatts of capacity to keep a 15 percent reserve margin. In traditionally-regulated systems, utilities were allowed to place the costs of maintaining this reserve margin in their rate base to recover those costs from their customers.

The shift to restructured markets and RTOs have created new mechanisms to meet this reserve requirement in competitive markets. One of these mechanisms are capacity markets, operated by the RTOs. Instead of requiring the utility alone to meet the reserve requirement, the requirement falls on what is known as the “load serving entity” (LSE). An LSE is any company that sells power directly to retail customers (collectively known as “load”). An LSE might be a utility or another independent electricity retailer. Those load serving entities must secure enough capacity to supply the peak load they expect to have, plus a reserve (typically 15 percent to 20 percent). Instead of building their own power plants or signing power purchase agreements to meet that need, the LSEs instead may go to a capacity market to buy capacity credits from power generators.[7] The combination of fixed-price bilateral contracts, real-time (spot) purchases, and day-ahead purchases allow retail suppliers and utilities to match the power supply to their obligation to serve the loads of their customers.

Payments from capacity markets give generators an incentive to build generation when and where it is needed. Low-capacity market prices indicate a surplus of electric generation in the region. High-capacity market prices indicate to generators that there is a need for new generation and boost the revenues that the generator earns by making this capacity available to the market in addition to simply selling the power. For the most part, capacity market prices have been low in recent years because of the abundance of available U.S. electric generation. However, by design this market is location-specific, providing higher capacity prices in regions that might need additional power generation resources. This is the case in places where electricity supplies are tight due to generation or transmission constraints— including much of the Eastern Seaboard between Washington, DC, New York City, and Boston, and parts of California. Capacity market prices in those areas are higher.

Generators can sell into the capacity markets and, in a new innovation, energy efficiency providers also can sell into the capacity markets, essentially guaranteeing a reduction in load opposed to new kilowatt-hours to meet additional load.

Renewable Energy Credits

A Renewable Energy Credit is an example of a revenue product created through state policies to encourage the development of renewable resources. Power generators using renewable energy to generate power may be able earn money by selling RECs in a market overseen by regulators where these credits are traded. When a renewable energy power plant—powered by wind, for instance—produces energy and delivers it into the power grid, the generator earns a certificate stating the number of megawatt hours of power it delivered into the grid. Under some state laws—generally a renewable portfolio standard—utilities may be under a legal obligation to use renewable energy. These utilities can, in many states, satisfy that obligation by buying a certain number of these RECs from the power generators. Others buy RECs to meet their own voluntary renewable energy goals. A city government might buy them in order to meet its self-imposed goals to meet a proportion of its energy needs with renewable energy. State, regional and private-sector markets for RECs are small and fragmented, though broadly speaking, these markets are growing and appearing in new areas. Nevertheless, the revenue stream from the sale of

[7] In theory, the LSEs also can use their own power plants to satisfy the 15-20 percent requirement, but many LSEs that operate where capacity markets exist have already sold their power plants, so they rely on the capacity market.

RECs is typically fairly modest and in it of itself not usually sufficient to spur construction of new resources.

Industry developments and market conditions pervade investments in electricity infrastructure. Challenges to investing in new infrastructure are discussed in Chapter 4.

How Power Plants Are Built and Financed

Understanding the general landscape and terminology of restructured markets is helpful when exploring the challenges to developing new generation in deregulated states, but how do developers, regulators, and others engage in the process of getting these plants from the drawing board into operation, given the lack of regulatory authority to command the development of new resources?

This chapter describes the major steps involved in building new power plants (henceforth simply called "generation"), from the early phases of determining the power system needs to the final stages of construction, thus demonstrating the influence each step has on financing. It also describes the major considerations that financial institutions incorporate into their decisions about individual projects or about the financial condition of energy companies.

> **Project development generally includes four steps[8]:**
> **Step 1: Identify a need for new infrastructure.**
> **Step 2: Choose the developer.**
> **Step 3: Choose the supplier.**
> **Step 4: Find funding for the facility.**

Step 1: Identify a need for new infrastructure.

Years before steel begins to go into the ground for a new power plant, some organization – a utility, a non-utility, independent generator, a regional transmission organization, or a utility commission -- has evaluated whether there is a need for it. In restructured states, power generators react to market conditions to decide when it makes sense to build new generation. The generators make this decision based on the expected revenues from the facility and the risk tolerance and desired return from investors. Generators earn money from energy, capacity and ancillary service markets, and consider each based on its predictability and size. Renewable energy generators can earn money from Renewable Energy Credit (REC) markets as well. With the exception of RECs, these revenue streams are obtained in wholesale power markets and the Federal Energy Regulatory Commission oversees them.

If the combination of these four payment streams is large enough and secure enough to justify building a new power plant, the generator will do so. In a few cases, the RTO or others may determine that the power system needs certain power plants to operate in specific locations because they play an important part in maintaining the reliability of the power system or provide power to customers

[8] Note that in traditionally regulated states, steps two, three, and four can be less emphasized due to the role played by the vertically integrated utility as the developer and supplier, and the role of the rate base in providing cost recovery for funding for the development. Still, these utilities can acquire resources by asking for bids and proposals from suppliers outside the utility, and in these cases vertically integrated utilities might also follow this four-step model.

in areas that have limited supply choices. Called "reliability must run" (RMR) facilities, these power plants provide important functions beyond energy production. They might, for example, provide electricity services (such as voltage support) to the transmission system where no other plants can do so. The opportunity to serve as an RMR facility may be better suited to existing power plants than to new plants.

Reliability Must Run (RMR) Facilities

Reliability must run (RMR) facilities are somewhat controversial. Most utility control areas and markets are likely to have some generating facilities that must run for reliability purposes. In restructured markets, however, they often operate outside the market in which other generators participate. They are not allowed to bid into the market or set the market price. The regulators or RTOs essentially have decided that the immediate market areas in which they operate are not sufficiently competitive to allow RMR generators to compete, or that they provide services to the grid that they must continue to provide even if the competitive market might not otherwise pay them to do so. These RMR facilities can be controversial when they become commonplace in certain markets. Independent generators voice concerns that too many RMR facilities inside an otherwise competitive market can significantly reduce the amount of true competition in that marketplace, since the RMR facilities do not need to compete for business.

San Diego, for example, needs to have available all the generation located in the San Diego Basin. Furthermore, San Diego needs all the transmission possible to bring additional power into the Basin. If power generators decided to shut down or diminish the output from their power plants, prices in the basin could skyrocket. The generators, in other words, had market power to influence prices in the San Diego marketplace. The stakeholders—utilities, power generators, customers, regulators and others—that created the California market design recognized this San Diego problem and included in their initial market design proposal to FERC that the facilities be operated as RMR facilities. This essentially meant keeping them out of the competitive market and operating them as regulated companies that run under a FERC tariff, which the California ISO enforces.

Other RMR facilities are designated as such because of reliability concerns. These RMR power plants, which provide local reactive power to the grid, may be required to run all or part of the time to provide this service. They essentially operate under an RMR contract with the RTO or ISO that, because it is a wholesale contract, generally falls under FERC jurisdiction. RMR contracts have become common in some markets; they represent a significant proportion of the contracts in New England's power markets, for example.

Step 2: Choose the developer.

After investors agree that they can achieve a desired return on investment and that there is a need for a new power plant, the infrastructure then must be built. The process, again, varies, depending on whether the market is restructured and whether transmission or generation is being built. This section describes the types of organizations that typically build power plants.

The choice about who will build new power plants is complex. It involves not only what kind of company builds the power plant, but also who selects the builder and what process is used.

The three general categories of new generation facility developers are: 1) the regulated utility; 2) a utility affiliate; or 3) a competitive generator or independent power producer that is not an affiliate of a utility. The following section describes the basic process for developing a new electricity generating facility using the three builder categories.

- *A utility*. As a component of electricity restructuring, many utilities discontinued the business of building power plants or moved this activity into a separate business unit of a consolidated energy holding company. Some utilities now are moving into the generation business again, however. In general, the only utilities that would consider building their own power plants are in the traditionally-regulated states. Even in these states, however, restrictions often are in place on whether they can build a new power plant and under what conditions they can do so.

The box below describes many of the restrictions on utility ownership of generation assets in restructured states.[9]

Utility Generation Ownership in Select Restructured States and Jurisdictions

- **Connecticut** – Recently passed legislation allows utilities to develop, own and operate up to 300 MW of distributed generation, after a competitive solicitation process.
- **Delaware** – All utility-owned generation was either divested or transferred to an affiliate.
- **Illinois** – All utility-owned generation is either divested or transferred to an affiliate.
- **Maine** – Restructuring law required utility divestiture of all generation except nuclear. The PUC can, however, allow utilities to have an equity position in a plant.
- **Maryland** – All utility-owned generation is either divested or transferred to an affiliate. The utility prohibited from owning generation.
- **Massachusetts** – All utility-owned generation is either divested or transferred to an affiliate. The utility is prohibited from owning generation.
- **New Hampshire** – Public Service of New Hampshire is the only utility that still owns its generation, but it must divest its generating assets if the Public Utilities Commission determines that it is in the economic interest of ratepayers. Public Service of New Hampshire, along with the state's other utilities, also is currently prohibited from adding generating assets to its portfolio.
- **New Jersey** – All utility-owned generation is either divested or transferred to an affiliate. The utility is prohibited from owning generation.
- **Rhode Island** – All utility-owned generation is either divested or transferred to an affiliate. The utility is prohibited from owning generation.
- **Texas** – The state required corporate unbundling between distribution utilities and generation-owning affiliates.
- **District of Columbia** – All utility-owned generation is either divested or transferred to an affiliate. Utility is prohibited from owning generation.

Source: Electric Power Supply Association, 2005.

A utility affiliate. Affiliates of utilities can build, own and operate power plants. In the mid-1990s, many regulated utilities formed generation affiliates that state regulators could not regulate; they instead fell under jurisdiction of FERC. The Southern Company formed Mirant, and Xcel Energy formed NRG, for example[10]. Some companies—First Energy in the Midwest for example—own more than one regulated utility. In recent years, the trend has been for utilities to leave the nonregulated generation business to focus on their regulated activities. Some utilities set up affiliates to sell their output in their own service territory or elsewhere. The lack of state regulation over the generating companies gave some of these facilities flexibility to sell their output into different markets and,

[9] The providers who have the obligation to serve—almost always utilities—are building generation in traditionally-regulated states.
[10] Both have subsequently been spun off by their affiliate companies, but these cases can still illustrate how such affiliate structures could operate.

perhaps, make more money for the parent company. If they do not own their own electricity generation, utilities must purchase power to serve the electric load of any customers' not taking competitive service. These generator utility affiliates may have to compete in power procurements that are conducted by their regulated utility affiliates.

A competitive generator that is not a utility affiliate. For purposes of this discussion, it also is important to distinguish between competitive generators that are utility affiliates and those that are not. The competitive generators that are not utility affiliates often bid in utility supply auctions against generators that are utility affiliates. State policies and FERC, through its code of conduct policy, seek to ensure that the utility affiliate does not have an advantage (such as preferential treatment or access to information that is not available to nonaffiliates) in the bidding process over a competitive generator that is not a utility affiliate.

Step 3: Choose the supplier.

One of the most controversial issues in building new utility infrastructure is selecting who will build it from among the choices listed in the previous section—the utility, a utility affiliate, or an independent power producer. States regulate how the utility (or, in some cases, the utility commission) procures resources. Here, again, restructured states and traditionally-regulated states diverge. This discussion first considers solicitations in restructured states, then auctions in traditionally-regulated states. It concludes with a discussion of the decision to build or not to build, whether or not the utility conducts a solicitation.

Most restructured states operate in wholesale power markets with a regional transmission organization (or a similar regional organization). In the states that also allow retail customers to choose an alternative electricity supplier, the utility's role often is limited to delivering power to its "standard offer" customers—those who have not chosen a competing power supplier[11]. In cases like this, large customers that use a great deal of electricity tend to look for savings by buying their power from an independent retail supplier that can offer better rates. Smaller customers, often commercial and residential, tend to buy their power from the utility. The utility, in turn, often conducts a procurement process to buy power on behalf of its customers, essentially acting as a purchasing agent for the customers. Customers choosing neither the utility nor an independent electricity supplier default to service from the utility and are typically known as default supply or provider of last resort (POLR) customers.

Procurement for the energy supply required to meet a specific load profile for one or more customers typically does not rely on specific generating plants. Energy suppliers agree to supply a certain amount of power to their customers, including the regulated utilities (often known as load serving entities [LSEs] because they serve the ultimate retail load). Generators then decide whether it is feasible to

[11] The utility provides electric distribution service to all customers in its service area whether they take standard offer or competitive service.

build a new power plant on the basis of the bid or other factors, whether to meet its obligations with existing plants it owns, or whether to buy the power on the wholesale power market and resell it to the utility. In this respect, many such solicitations are a departure from those conducted by utilities in traditionally-regulated states.

Procurement for Default Supply

A procurement to serve default supply typically proceeds in this fashion.

1. The state's utility commission determines that the utility should be responsible for conducting procurement to supply power to customers who have not chosen an alternative electricity provider.
2. The utility commission, with input from the state's utilities, consumers, suppliers and other interveners, sets up the structure for the procurement. It addresses such issues as:
   - The size of the load to be served.
   - The length of supply contracts (three, five, 10 years).
   - Size of bid increments (100 MWs, for instance).
   - Other characteristics of the supply (green, renewable power).
   - Mechanism for conducting the procurement, i.e., electronic auction, sealed bids, in person, Internet.
   - Many other issues.
3. The commission may hire a third-party monitor/evaluator to oversee the procurement.
4. The utility or utility commission conducts the procurement.
5. The utility commission approves the auction results, allowing the distribution utilities to recover its costs through the rates it charges customers.

Lessons for restructured states when selecting the energy provider

The simplified process by which a utility selects an energy supplier is not difficult to understand, but many design details make it complex. Only a few of the many complexities of the bidding process are described here.

One way a utility selects an energy provider is by using the POLR[12] method. Most POLR procurements conducted by utilities are auctions for so-called full requirements service. In full requirements service, the power supplier takes responsibility for all or a portion of the total load, typically including:

- energy,
- capacity,
- transmission,
- ancillary services,
- renewable energy resources (if required),
- transmission and distribution losses,
- congestion costs, and
- all other services required to supply the specified amount of energy for distribution service.

[12] "Provider of last resort" refers to the company that supplies power to customers who have either not chosen an alternative supplier or who have been with an alternative supplier but then returned to the POLR service for one of several reasons.

In Maryland, for example, a supplier might agree to supply 5 percent of total POLR load at a particular price. The supplier actually bears the risk if the load goes up or down, since the agreement is always based on a percent of the POLR load at every hour.

This arrangement is particularly suited for restructured states where customers are free to buy power from whomever they choose. If a new power marketer enters the territory with a wonderful deal—a 15 percent discount off the current price of power with a five-year guarantee, for instance—500,000 customers might choose that other supplier. If, later on, the wonderful deal disappears and those 500,000 customers come back to the POLR, it is the supplier's responsibility to absorb their defined share of this increase in POLR demand. A large, liquid and functioning wholesale market is vital to making this structure workable. Absent that efficient wholesale market, the supplier would have nowhere to sell its power in the event many customers leave the market. In the event that demand increases dramatically, the supplier would otherwise have no way to buy power from other generators in order to meet that new demand. This is at the heart of the problem for financing projects in restructured states: market fluidity creates a situation where suppliers are only willing to enter into short term contracts so they are not stranded with long-term costs if their customer base leaves for a competitive supplier. This short term contract problem makes it difficult to finance plants

The terms of the procurement also help create a financial guarantee for the utility and a degree of retail rate stability. If the supplier enters into a contract to sell power at $60 per megawatt hour, it must provide the promised amount of power at that price, despite the cost, or face significant penalties.

In both cases, the risk is the supplier's, and the consumer and the utility have supply and price guarantees for the length of the contract. However, the supplier will consider these market risks when it offers bids and prices to the utility. In areas where prices recently have increased, it is likely that older (lower cost) contracts had expired and new ones (based on higher wholesale market prices) have taken effect.

The Effect of New Generation on Prices in Restructured Markets

The effect of new generation on electric rates differs in traditionally-regulated and restructured states. When new generation is added to the retail rate base in unrestricted states, its costs are rolled into existing rate base investments to produce rates based on average costs. In restructured states, new generation is added at the wholesale level, meaning that the prices of electricity are 1) beyond the authority of the state, and 2) priced-based on whatever system is in place for the wholesale energy market. This is most frequently a form of locational marginal pricing (LMP), a system that prices electricity differently, depending on where the power plants are located. In a situation such as that in PJM (a wholesale power market that serves the Mid-Atlantic and parts of the Southeast and Midwest), the new generator will receive whatever the marginal cost of energy is in the market at the time when and where the new plant is producing. The price effects of new generation therefore differ significantly in traditionally-regulated and restructured markets.

Decisions to Build Infrastructure Outside of a State-Regulated Procurement Process

Markets determine energy suppliers without a centralized request for new supply. In the idealized free market for energy, neither centralized procurements to serve default supply customers nor utility-run bids for supply would be necessary. The markets themselves would supply the correct price incentives to provide energy supplies and would not require centralized intervention.

Today's restructured markets have made progress toward this end, but they remain a hybrid blend of regulation and free markets. Generators operating in wholesale markets rely on price signals that collectively encourage or discourage them to build new capacity. As described in Chapter 2, these price signals come from a combination of the energy markets, ancillary service markets and capacity markets. Renewable energy power companies also sometimes benefit from renewable energy credit markets. This section focuses on the capacity market because they are the subject of greatest discussion and debate in states that deregulated their electricity markets at the moment.

Capacity Markets. The Federal Energy Regulatory Commission's 2004 assessment of capacity markets is that the markets have indicated a surplus of electric capacity fairly well throughout the country. Table 2 shows how New York City's capacity payments are significantly higher than elsewhere in the Eastern United States.

Table 2. Sample Capacity Payments, 2004

Region	Area	$/kilowatt-year
NYISO	New York City	$135.25
NYISO	Rest of New York	$16.65
PJM	Mid-Atlantic & Midwest	$5.24 to $5.38
ISO-NE	New England	$0.36

Source: FERC, *2004 State of the Markets Report*, PJM Interconnection, NYISO and ISO-NE market monitoring units, 2004.

In the broader context, capacity payments can be evaluated by how much they have paid over time (reflecting a growing overcapacity situation in much of the United States) and how much they offer in combination with energy markets. Figure 3 shows capacity and energy revenues for two Pennsylvania power plants.

Figure 3. Estimated Revenues for Selected Facilities Based on Market Prices (in Thousands of Dollars)

Eddystone (Units 1 and 2, Coal Fired, Total Generating Capacity: 581 MW)

	1999	2000	2001	2002	2003	2004

Energy	$79,929	$86,561	$125,124	$88,607	$131,382	$134,597
Capacity	$11,210	$12,841	$20,218	$7,083	$3,713	$3,762
Total	$91,139	$99,401	$145,342	$95,689	$135,095	$138,359

Limerick (Nuclear Facility. Total Generating Capacity: 2268 MW)

	1999	**2000**	**2001**	**2002**	**2003**	**2004**
Energy	$519,526	$539,387	$611,753	$544,485	$751,710	$870,302
Capacity	$43,759	$50,125	$78,924	$27,649	$14,495	$14,686
Total	$563,285	$589,512	$690,677	$572,134	$766,205	$884,988

Source: Synapse Energy, *2004 Capacity Revenues for Existing, Base Load Generation in the PJM Interconnection: A Pennsylvania Case Study,* 2005.

The combination of energy and capacity payments generally has been too small to encourage generators to build new power plants or even to propose new power plants. FERC, in its *2004 State of the Markets Report*, estimates that the revenues from the combination of energy and capacity markets will not be sufficient to cover the investment in a new gas fired power plant—the least expensive type of generator. A natural gas combined cycle power plant built in the western PJM area would have been able to recover only 39 percent of its target net revenue; a natural gas combustion turbine would have recovered only 9 percent of its target net revenue. The situation in other restructured markets is similar.

Capacity market structure creates a curious dynamic, which has become a disincentive to build new power plants. Generators want capacity prices to increase, and they also want energy prices to increase. These increases will help them earn more money, but they also will encourage new generators to enter the market, chasing those same high prices. When the new entrants begin to supply power, however, energy and capacity supply problems diminish and, as a result, energy and capacity prices decline. Thus, the financial projections that generators use to finance their power plants must change. Some generators and the financial community would prefer that energy and capacity prices be more certain. Others feel they can predict with enough certainty what those future prices will be so long as the power market is structured properly. This debate is part of the much larger question of how much risk the financial community and generators are willing to take on future prices. How much certainty do they need before they will make an investment of $100 million to $1 billion? More fundamentally, will the combination of capacity and energy markets lead to sufficient construction fast enough to meet short- to medium-term needs? The answer to all these questions generally is that the financial community prefers less risk and thereby will require lower returns on its investment capital.

The Public Utility Regulatory Policies Act

Renewable energy and some other small-scale generators—known as qualifying facilities (QFs)—in regulated states have had at their disposal another mechanism to secure a power purchase agreement. The 1978 Public Utility Regulatory Policies Act (PURPA) set up a system under which utilities were required to buy power at their own "avoided cost" from certain small-scale generators, generally those under 80 MW total capacity. Utility commissions set the rates for these avoided costs, which are meant to be the cost that the utility would otherwise incur to secure power from its own facilities or to buy power on the market. For example, Idaho's PURPA rates, set at $61 per megawatt-hour (6.1 cents per kilowatt-hour) for 20 years, are available to renewable developers, although only small-scale wind developers (up to 100 kW) qualify. In the past, wind developers in Idaho could be as large as 10 MW to qualify for the special rate.

The 2005 Energy Policy Act reformed PURPA, asking FERC to develop new PURPA regulations. In compliance with the act, FERC proposed changes to the mandatory purchase regulations under PURPA. According to the energy bill, qualifying facilities' benefits terminate when the QF has access to a competitive wholesale market, thereby releasing a local utility from being the "captive buyer." The actual definition of access to a competitive market is somewhat unclear at the moment, but FERC has proposed that it center on whether the generator is located within an RTO. If the generator does not have access to a competitive market, then state commission authority to set PURPA rates and terms remains largely unchanged. FERC also has set out new criteria for future QFs to ensure that they are fundamentally designed to support commercial or industrial processes.

Step 4: Find Funding for the Facility.

Banks and equity investors provide the capital to finance new utility infrastructure, whether it is transmission or distribution, and whether it is in regulated or restructured energy markets. Their evaluation of where to invest is based upon many factors, but their final decision balances risk and return. They expect to earn a return on their investment that compensates for their risk. Higher risk equates with higher returns, so any perception that a company is in poor financial condition or that a power plant may not perform well means a higher cost of capital for that company or that plant.

The financial institutions evaluate the safety of their investment. A changing or unpredictable regulatory structure elevates risk, and in such a case the financial community is less likely to invest. Similarly, it will be difficult to attract inexpensive investment capital for a new, higher risk, untried energy technology. The financial community will offer less expensive capital to the energy industry if regulators and policymakers create a stable regulatory climate that sends clear signals about the direction of future energy policy.

But how much do power plants cost? The cost of electricity infrastructure varies, depending on particular conditions, but it is nonetheless possible to provide a general estimate of costs. Table 3 provides general data on the capital cost for several types of power plants; by way of comparison, Table 4 shows typical costs for electric transmission lines.

Table 3. Power Plant Capital Costs per kilowatt

Coal	Natural Gas	Nuclear	Wind	Geothermal
$1,000-$1,200	$500-$800	$1,200-$1,800	$1,000-$1,200	$2,100-$3,500

Source: NCSL, 2005.

Table 4. Typical Capital Costs for Electric Transmission Lines, by Voltage

Transmission Facility	Typical Capital Cost
New 345 kilovolt (kV) single circuit line	$915,000 per mile
New 345 kV double circuit line	$1.71 million per mile
New 138 kV single circuit line	$390,000 per mile
New 138 kV double circuit line	$540,000 per mile
New 69 kV single circuit line	$285,000 per mile
New 69 kV double circuit line	$380,000 per mile
Single circuit underground lines	Approximately four times the cost of aboveground single circuit lines.
Rebuild/Upgrade 69 kV line to 138 kV line	$400,000 per mile

Source: American Transmission Company, *10-Year Transmission Assessment*, September 2003.

Financing Power Plants

This section describes the process though which a typical energy company or energy project obtains financing. It describes the typical considerations that lenders and equity investors consider when they decide whether to invest in a new energy project or to invest in or lend to an energy company. Appendix A describes some of the organizations that provide financing in more detail.

Independent energy project developers often use a project finance process to fund their projects. Project finance relies on revenues from specific projects to repay lenders and provide returns to equity investors. It does not rely explicitly on the credit of the project's sponsors or developers but, instead, on the return and risk of the project itself. Project finance also is usually no-recourse; that is, if the project cannot meet its obligations, the lenders may look only to the project's assets and cannot pursue the developer's or sponsor's assets to repay the project loan. The process allows borrowers to raise money for large, capital-intensive projects such as power plants or transmission lines. Project finance also is a common financing practice in other capital-intensive industries such as mining or shipping and in some major construction projects.[13]

Many developers find project finance structures useful for a variety of reasons. The credit appraisal of individual projects may be more favorable than the appraisal of the developer itself. Projects become possible that would not be financed based only on the developer's financial profile.

[13] For example, the English Channel Tunnel sponsors raised money for this project using this project finance process.

- Project finance leaves sponsors free to pursue several projects simultaneously, each based on its own merits. Each project is financed separately, so the failure of one project will not cause failure of another.
- Major corporations that are capable of financing projects through other means may use project finance to isolate the effects of the project's debt to equity ratio from its own balance sheet, although such structures have become rare in recent years.
- Project finance also allocates risks to those who can best bear them. Construction risk is borne by the contractor who builds the facility; the risk that fuel prices will change radically can be allocated to the fuel supplier, and so on.
- Project financing also can allow participants to allocate tax benefits of some projects to those who can best use them.
- Other financing techniques may not provide the same flexibility for the developer to invest in multiple projects.

Many energy projects also obtain financing through the more familiar corporate finance process that relies on the credit rating of the particular developer, whether it is a utility or an independent generator. This process considers the financial health of the entity itself—the history and financial condition of the utility or developer. It is difficult in these situations to determine the precise effect of particular projects on the entity's overall condition. This process considers such questions as the basic financial condition of the entity in terms of its ability to cover its debt payments, its cash reserves, and so forth. It also more broadly considers the state of the industry and the regulated environment in which it operates. When Enron collapsed and California's electric power industry fell into crisis, bond ratings fell and overall risk profiles increased for the entire power industry. The corporate finance process, therefore, is not based on individual projects as isolated financed efforts but, instead, on the financial condition of the entire company and the industry sector as a whole.

Project financing has disadvantages. First, it typically is expensive. Lenders require careful due diligence engineering and financial reviews, which cause high transaction costs. Second, interest rates can be higher than for a typical direct loan. Finally, project financing also often involves restrictive covenants and supervision.

A hypothetical example is included as Appendix B, that may serve as an illustration of the financing process for an energy project and the cash flows involved in the process. The process the financial community uses to assess individual projects is similar in many ways to that used to assess the broader financial condition of energy companies in both the project finance and the corporate finance process.

Challenges to Financing Generation Infrastructure

A close look at the overall electric industry reveals some barriers to building new infrastructure, particularly in restructured states. Separated from the model of funding new infrastructure via public utility commission-approved rates, a number of questions arise that have different answers in different areas: what will new infrastructure cost? Who pays for it? How certain can a utility or developer be of whether the investment will pay off?

This chapter describes the major policy issues that affect the financing of new power plants in restructured states. In the simplest terms, changes in the consumption of energy, new technologies available to developers, restructuring, and the shift to regional markets altered the world in which states once had a great deal of influence in bringing about new generation infrastructure.

These states are working to set goals and develop a clear, dependable, transparent and flexible policy and regulatory process, on the assumption that if individual policies adhere to those principles, it will be far easier to resolve many of the underlying issues—the need for adequate generating capacity, the need for power industry companies to be in good financial condition, and the need for fuel diversity. Underlying this policy discussion is a general set of goals for the electric industry: to reliably and safely produce and deliver affordable electricity in a manner consistent with environmental goals at the least cost.

Challenge 1: Insufficient Long-Term Capacity in Reserve and Absent Financial Certainty to Invest

Restructuring dramatically changed the role of the state public utility commission in ensuring that new power plants would be built. Instead of utilities planning for new facilities based on forecasted load with assurance that cost recovery would be approved for prudent investments that met need, market forces now drive investment to where it will be most financially rewarding. In some cases, this has created concern in restructured states that adequate reserves cannot be brought to market at the lowest cost.

In regulated states, investors are more likely to feel there is the financial assurance of a return on their investment and cost recovery for the utility via a public utility commission hearing to approve the construction or acquisition of new resources. In restructured states, new resources are built when markets indicate they should be, but this process can be perceived as far more risky for investors. In many restructured states, the responsibility for maintaining adequate capacity may fall to the RTO or system operator, which places requirements on the load-serving entity to ensure that it has secured enough capacity to meet its forecasted load requirements and also has a reserve margin.

How much assurance can utilities in restructured states receive—and when should they receive that assurance—about recovering costs passed through by suppliers for investing in new energy infrastructure? Under the old system of traditional cost-of-service regulation, public utility commissions approved cost recovery; in restructured, regional markets, regulators have little direct influence over the market signals that motivate new investment. In a restructured market, how can regulators provide the right incentives and signals to provide such assurances? One avenue may be to approve prudent cost recovery by load-serving entities for their power purchases. Utilities that operate solicitations for energy resources may feel it is critical to be assured that, if the solicitation meets utility commission specifications, they will be able to recover the costs of purchasing power in their rates and that these assurances will not be rescinded later at the regulatory or legislative level.

Challenge 2: Resource Inadequacy and Inadequate Capacity Markets in Restructured States

This issue is closely related to the previous unresolved policy issue of assuring sufficient capacity and reserves. Resource adequacy addresses the question of adequate generating capacity. The fundamental question in restructured markets is who pays for resource adequacy. At the moment, those in the financial community and generators want to know what their return will be for helping meet resource adequacy requirements. They complain that, at the moment, the answer is a combination of “don’t know” and “not much.”

In RTO markets, capacity payments pay generators to be available to generate power. Those rules are in flux at the moment, and the size of capacity payments are invariably argued as being either too small or too large. Until the rules that govern the payments are clear, bankers will discount their value heavily. The larger question is how these payments will be structured to both offer enough certainty that they become a revenue stream that bankers and others can rely upon, and also be certain to offer enough lead time in the price signal they send to convince people to plan and propose new generation several years in advance of the time it is actually needed.

Many power generators have been unhappy with capacity auction markets, feeling that capacity payments are neither large enough nor dependable enough to truly encourage them to build a new power plant. Some suggest capacity markets in fact are not necessary and that energy markets are sufficient. Others suggest that capacity markets are structured poorly. Many agree that capacity markets are not, by themselves, enough to encourage construction of new power plants, and the uncertainty about their structure only makes them less effective. Still others believe that capacity markets may yet be successful, that they need to be structured more effectively, and that they be allowed to function over a period of time to determine their effect.

Challenge 3: The Need to Manage Fuel Risks and Diversify Resources

Many in the energy industry agree that, in principle, it makes sense to have a diverse portfolio of fuels and technologies to generate and deliver power. This diverse portfolio helps the energy industry reduce its overall risks from price spikes or supply shortages. Directions that may create this diversity include renewable energy, new coal technologies, energy efficiency, demand response, nuclear power and gas. Questions arise, however, in the details about who will pay for that diversity and under what conditions they will financially support it. Companies do not want to be penalized by regulators if they select an apparently low-risk strategy that may cost more in the short-term but saves money over the long-term.[14]

In the absence of a major and unforeseen technological breakthrough, every fuel that is used to generate electricity has limitations. Gas and coal prices are increasingly high and volatile, and fossil fuels emit air pollutants and greenhouse gases that are of concern. Nuclear waste disposal remains an unanswered problem, and few sites remain for hydroelectric development. Renewables are the fastest-growing generation sources today, but face cost competitiveness hurdles as they increasingly enter into the market. Among renewables, the most cost competitive is wind energy, but it too is an intermittent source that has siting and transmission connection challenges to overcome in some areas of the country.

There is little diversification of fuels in the power plants built in the past fifteen years, particularly in restructured states. Apart from renewable portfolio standards that required power systems to accommodate a certain amount of renewable energy, most new power plants built in the past decade use natural gas. Natural gas powered power plants can produce power with low emissions, are flexible because they adapt their electrical output to match the needs of the electric system easily, and have the lowest capital cost of all the major fossil fuel power generation sources. After a long period of sustained low natural gas prices until 2000-2001, however, gas prices have become volatile, at times reaching levels 500 percent to 700 percent higher than 1999-2000 levels. This price volatility and the concern that it may continue for years into the future have made investments in natural gas power plants appear riskier and less attractive

[14] Significantly, risk management involves not only managing resource decisions and choices, but also allocating those risks to different parties, using financial hedging instruments. The goal of risk management is completely different from that of integrated resource planning, (IRP). IRP is a utility planning process that involves choosing the lowest cost resources between alternatives. In contrast, risk management involves finding a counterparty to bear some of the uncertainty surrounding the likely costs or payoffs to a particular investment or contract. Thus risk management involves no attempt to choose among alternatives that have different expected, present value costs. Rather, it involves choosing among alternative ways of bearing the risk of a given investment, with the same expected total cost for all alternative patterns. The alternative risk management strategies differ only in the range of outcomes that could ensue and in which of the parties to the transaction bears the exposure to which potential outcome. After the fact, one or the other of the parties to a hedging contract will appear to have "won" because it outperformed an unhedged position. That is not cost management, just good fortune. Summarized from Frank Graves and Angela Baker, The Brattle Group, *Disincentives to Utility Investment in the Current World of "Competitive Regulation* (Washington, D.C.; Edison Electric Institute, 2004), 18.

than they were a few years ago, when they constituted the bulk of new power plants being built in the United States.

Advanced technologies in some fuel sectors, such as coal gasification with carbon capture, are on the horizon. However, many of these technologies are in the early stages of being proven in large-scale applications. Investors are hesitant to adopt new technologies that might offer cleaner, more efficient power generation, as they are concerned about the initial costs and recovery of costs due to the lack of absolute information on these technologies. Current policy and market structure are not encouraging the investment in technologically advanced power plants.

Challenge 4: Uncertainty in Regulatory Policy

Those in the energy industry and the finance community may be reluctant to make major investments in new energy infrastructure in the absence of a strong and consistent energy policy. In some respects, this complaint may seem overly abstract; however, the absence of clearly stated priorities makes decision making difficult. This is especially true in the energy industry, where expensive power plants built today will likely still be in use in thirty or even fifty years. Two major issues serve as examples.

How much priority will policymakers give environmental issues?

Coal is an abundant and inexpensive fuel for U.S. power plants and, with recent higher natural gas prices, coal has become increasingly attractive for electricity generation. The burning of fossil fuels like coal and gas releases carbon dioxide, which has been identified as a contributor to global climate change. New regulations and laws in the states and proposals in Congress indicate that carbon regulations could become more widespread. These regulations could require power companies to make significant investments to capture or reduce carbon emissions from their power plants, or purchase carbon credits if they do not reduce emissions. Developers of new generation must decide whether to invest in carbon capture or control technology, or select another type of generation without carbon emissions, but if regulatory drivers do not emerge, these investments may make new developments uncompetitive with plants that have not made these emissions control investments. The resulting uncertainty about the future of carbon regulation increases the perception of risk in today's power markets.

A major emphasis on climate change among policy-makers would encourage investors to put their money today into such new technologies as carbon capture-capable power plants or restrict the types of power plants that can be built, which could adversely affect fuel diversity objectives. It may imply greater investment in energy efficiency that, in turn, suggests lower demand growth for energy, less need for new power plants, and possible expansion of the throughput capability of the system of power lines. It also may imply a cap on carbon emissions with a trading system to enable some who exceed the cap to buy credits from those whose emissions fall below the cap. Less emphasis on climate and on air pollution control by policy-makers would discourage taking the path of investments that support carbon reductions.

How committed are policymakers to deregulation?
The United States currently operates in a hybrid condition where regulated and deregulated states co-exist. Some argue that this hybrid does not yield the benefits of either and that the uncertainty alone breeds a climate that is not investment-friendly. In the early days of deregulation, some wondered how many more states would open power markets to competition. With deregulation halted and in some cases reversed, many now wonder how many states will choose to return to a model of traditional regulation.

Clear policy statements on these two issues—as well as a host of related issues—would begin to create a more hospitable investment climate and create a strong foundation for new, broader policies.

Challenge 5: The market's boom and bust cycle is unhealthy for investment in restructured states.
In states that chose to move to competition-based models in the early 1990s, market forces such as demand and fuel price, and forecasts of those forces, were used to decide when and where to build power plants instead of the more centralized planning of the traditional regulation model. In those states, the resulting trend was to build many power plants in a short time and then build none for several years. During the late 1990s and continuing into the first years of this decade, there was substantial investment in generation and a surplus of power plant capacity was built up in many regions of the country. High prices that result from tight supply attracted companies to build; subsequent lowering of prices that resulted from an over-supplied market for power plants discouraged companies from building more new infrastructure.[15]

There is growing concern about the long-term ability of the electric system to deliver a reliable supply to meet growing electric demands. Although electricity prices have risen considerably in the recent past, these were driven not only by tight supply, but also by rapid escalation of fuel prices. When fuel prices are removed from the equation, then electricity prices (or, more specifically, the electric companies' profits) generally are not high enough to stimulate new investment. There also is concern about when electricity prices will increase enough[16] to encourage new construction and whether problems will result if new

[15] In its *2004 State of the Markets* report, the Federal Energy Regulatory Commission (FERC) estimated that the returns were too small to justify building a new plant anywhere in the country. Federal Energy Regulatory Commission, *2004 State of the Markets Report*, Washington, DC, June 2005).
[16] The increase in prices referred to here would have to reflect more than just a pass-through of higher fuel prices in order to indicate a need for new capacity.

plants are delayed until sustained high prices reflect real supply shortages. It could easily take five to 10 years to plan, finance, permit and construct a coal-fired power plant; generally, this is a far shorter time than that required for a nuclear plant or major transmission line, longer than for a gas-fired plant, and considerably longer than for a utility-scale wind energy project. For a merchant power plant developer, this raises the question of whether the current structure in restructured states creates the adequate incentives and flexibility to plan, finance, permit and build a diverse range of new plant types without creating electricity shortages in the interim.

Some market assessments indicate that new generation capacity will be needed in the coming half-decade. For plants to be built and operating in that time frame, planning, permitting and financing arrangements must begin now. The resulting lag time means that if development depends on the developers of power plants that serve restructured states receiving unambiguous price signals, then new generation capacity may not come on line when it is needed, and higher prices and supply shortages could result. Many argue that the market has not seen *real* price signals because of government- imposed price caps or generally immature capacity markets in many parts of the country.

Challenge 6: Transmission Complicates Generation Investment Decisions

All generation needs transmission of some sort, and permitting transmission can be a lengthy process, with opposition to siting new lines complicating development. These factors add to the perception of risk in power markets.

Power generators earn more money when they sell power within an area that really needs the power—one where there is a relative scarcity of power generation. A region might have such scarcity because of population or economic growth coupled with a power system that did not keep up with the increasing demands for electricity. Scarcity of generation also might result from insufficient transmission capacity to bring power into an area.

One tool that has been developed in restructured states attempts to reflect the higher value of generation in these areas is locational marginal pricing (LMP). LMPs are a market tool designed to direct investments in generation or transmission to constrained areas. Those who produce and deliver power in these constrained areas can earn more money for that power because locational marginal prices are higher in constrained areas than in areas with ample power supplies. The high LMPs in constrained areas, along with other payment streams, should encourage generators to build in the constrained areas, since the returns will be higher than in other areas that are not congested. Furthermore, capacity payments are higher in constrained areas.

In southwest Connecticut, the transmission system has limited ability to bring power into the area. At the same time, the supply of power from generators located with the area is tight because the supply of new power generation capacity has not kept up with the rising demand for power. As a result of the tight balance between supply and demand, prices are higher than they are in much of the surrounding area, where the situation is not as tight.

Generators who build in a constrained area such as southwest Connecticut know that prices will decline when they start to deliver power into the area, since prices decline when supplies are ample. They take a well-calculated risk, based on what they estimate the new prices will be once they start to deliver power. However, investment decisions about generation (that, in some cases, occur in a market context) affect investment decisions about transmission (that, in most cases, occur in a regulated context). The reverse also is true: transmission investments affect generation.

Imagine that a generator takes the calculated risk to build in a constrained area such as southwest Connecticut. Then further imagine that the transmission company serving that area decides to build a transmission line. The transmission company is most likely a regulated company, earning a regulated, assured rate of return under a tariff approved by the FERC. The generator suddenly faces competition from power delivered into the area from elsewhere, and prices tumble. The calculated market risk that the generator has taken is now undermined by the decision to build a regulated transmission line.

Conclusion

The electricity industry is constantly evolving. Policy and market shifts that occurred in the past decade created a new landscape in the power sector that is still being understood by market participants, decision-makers, and the public, and this new landscape holds new challenges and opportunities for building and paying for electricity infrastructure. Policymakers have an opportunity to remove impediments and create a favorable climate for the next iteration of proven and emerging technologies that can deliver reliable, affordable, environmentally-friendly electricity to consumers.

By sending clear and consistent policy messages, prioritizing and acting to facilitate fuel diversity, taking steps to ensure long-term capacity and, in restructured markets, resource adequacy, and by lowering the barriers to financing infrastructure, those involved in electricity policy can help bring the national electric system into the 21st century.

Key questions remain for decision-makers in restructured states. In the face of regionalized markets, how can states attract sufficient generation resources and long-term capacity in reserve? What will provide developers the needed regulatory and financial comfort that will encourage that investment? How can capacity markets and ancillary markets be reformed to provide effective market signals? If states can encourage investment, how can they diversify their resources to manage the risks of price spikes for specific fuels, and encourage state policy preferences like renewable energy? Will the states that have chosen to move towards a restructured model remain on that path? How can decision-makers attract provide a stable regulatory platform that minimizes risk to those interested in making these investments? How can they structure market mechanisms that provide effective price signals without putting at risk the entities providing default service? This paper is intended to give state decision-makers the basic vocabulary to engage in these debates.

While there are early answers about how to finance and build this generation of technologies, a host of emerging technologies will continue to challenge policy-makers in the future. The intelligent grid, grand-scale distributed generation, as-yet unbuilt nuclear, fossil, and renewable energy generation technologies, nanotechnology, and the infrastructure needed to fulfill the promise of the hydrogen economy will create new questions about how to finance and create the *next* generation of electricity infrastructure.

Appendix A. Financing Sources

Three types of organizations provide or arrange financing for both renewable and conventional energy projects—investment banks, lenders and investors. Each has its own interests, its own time over which it wants to recover its money and its own restrictions. A brief overview follows of each of these parties and roles in the financing process.

Investment Banks

Investment banks arrange financing. They usually do not provide the money. Instead, they broker deals between those who need money (the project sponsors) and those who want to lend or invest it (the banks or other financial institutions). The investment banks earn their money from fees on the transactions they broker.

A good investment banker should consider a project from the perspective of those who may invest in it. Investment bankers, therefore, need to understand the objectives, desires and restrictions of potential investors. Investment bankers may be the first contact for a project developer. Typically, an investment banker analyzes a project and, if it seems viable, will contact people who are likely to invest.

Two types of investment banks are important in the energy project finance field: boutique and large investment banks. These banks are distinguished by their size and specialty. Boutique investment banks generally deal with smaller transactions, while larger investment banks handle transactions that generate larger fees to cover their higher overhead costs.[17] Many renewable energy projects, because they are smaller than gas, oil or coal-fired facilities, will be brokered by the boutique investment banks.

Commercial Banks and Other Institutional Lenders

Commercial banks loan money to project developers through departments that specialize in project finance.

Subordinated Lenders

Subordinated lenders are a hybrid of equity investors and senior lenders. Subordinated lenders—such as the pension management firm Trust Company for the West—will be paid after the senior lenders but before equity investors. Their loan is at greater risk than that of the senior lenders. To compensate for the higher risks they accept, the subordinated lenders receive a higher interest rate and, perhaps, some participation in the equity. Subordinate loans fill out the riskier—and higher return—portion of a lenders loan portfolio. Because they are

[17] The larger banks frequently have higher overhead costs in part because of larger offices and more staff. Many so-called boutique investment banking firms have small offices with fewer staff.

lenders, not equity investors, however, they are paid before the equity investors and are senior to the equity in the event the project fails. If a project fails, subordinated debt holders are unlikely to benefit from their priority to the equity. Even the senior debt is unlikely to be covered.

Equity Investors and Green Funding

Equity investors typically provide 10 percent to 25 percent of the project's costs and assume the greatest risk because they are last to be paid. However, they are compensated for taking the financial risk; pretax equity rates range as high as 25 percent. Equity investors approach project finance from a different perspective than lenders. Equity investors carefully consider the tax benefits of investing in energy projects. Thus, the tax credits, tax deductions and accelerated depreciation schedules that accrue to renewable energy projects or other specifically favored technologies are germane to equity investors.

Appendix B: A Hypothetical Example.[18]

The following example describes the financing process for building new generation. In practice, the financing process is far more complex and variable. The example focuses on a situation in which a utility has conducted a bid to buy power from a specific power plant—the unit contingent bid. This type of utility—which would be most common in traditionally-regulated states—is used to illustrate key points about the financing process. The example continually refers to considerations in the financing process that are relevant in both restructured and traditionally-regulated states.

Western Development Corporation (WDC), a medium-size independent generator, responded to a unit contingent competitive bid solicitation of a large utility, Consolidated Public Service (CPS). WDC offered to build a power plant at a price lower than its competitors' offers in the same procurement. CPS has accepted the bid at the price WDC offered, and the two have signed a 10-year power sales agreement.[19] WDC also has received all the necessary permits to build the power plant.

- In the case of a wind power plant, WDC would have completed the wind resource studies and most of the engineering work necessary for the project. WDC's engineering work would have focused on identifying the size and type of wind turbines to use, based on cost/benefit analysis and site-specific wind speed data.

- If WDC were building a coal or a gas fired power plant, it would present CPS with its long-term fuel supply agreements to demonstrate that it will be able to buy the fuel to power the plant. The engineering work would focus on securing reliable gas turbines from a reputable company or well-engineered coal boiler facilities. WDC also might consider using new technology coal plants, such as efficient and low-emission integrated gas combined cycle facilities. Its decision about whether to use new technology would be based partly on the experience with the technology (new technology implies higher risk that it might not operate as planned, meaning, for example, higher emissions, more outages or lower electrical output). Chances are slim that it would adopt a new technology without significant outside support such as government subsidies.

---

[18] None of the names used here represent real companies. The example focuses on a wind plant to demonstrate certain wind/renewable energy specific elements of the financing process. It describes throughout the differences that would exist for a gas or coal fired facility.

[19] As described earlier in this document, a 10-year power purchase agreement might be longer than now is common. In addition, although this example uses a power purchase agreement, many points described here are equally relevant for utility-built facilities. Some of those commonalities and differences are identified throughout the example.

WDC also has completed a financial model showing how the project will incur expenses and generate revenue. WDC now needs money to continue. Because it does not have the internal capital to build the facility, it uses the project finance process to raise $500 million.[20]

WDC secures an investment banker to guide it through the process, to help structure the deal, and to make contact with potential lenders and investors. The investment banker will charge a fee, but the assistance will be invaluable because WDC does not have the necessary contacts to secure the money to build the project. After a close examination of WDC and the project, the investment banker feels comfortable that WDC is a reliable project sponsor/developer and that the project will perform as WDC says it will. The investment banker then takes the project to a number of banks.

One large commercial bank, Commercial One, is interested in becoming the senior lender for the project. The power purchase agreement is the primary source of revenue for the project, and the bank scrutinizes it in detail. Its close appraisal of the project focuses on several specifics.

Power Purchase Agreement. Commercial One examines the power purchase agreement. As do all the investors and lenders involved in the project, the bank uses the power purchase agreement as assurance that it will receive its interest and principal payments. The bank prefers to have a long-term power purchase agreement of at least 10 years. In markets in many traditionally-regulated states, Commercial One expects such a long-term contract. In the restructured states, shorter-term power purchase contracts—on the order of three to five years or shorter—are more common. In these situations, the bank will consider not only the power purchase agreement, but also to the strength, robustness and predictability of the wholesale power market. As a typical commercial bank, Commercial One offers a three-year "construction loan" (the three-year loan used to finance construction of the project) plus a multi-year "term loan" that begins once the project is built and producing power. Other lenders, such as insurance companies, may offer longer-term loans.

Credit History. Commercial One also examines the credit history of CPS to ensure that CPS can meet its obligations to buy power. It is important that both parties to the agreement be on strong financial footing from the outset. The bank also will consider the regulatory environment in which CPS operates to obtain some assurance that the utility will be able to recover the costs of the power purchase agreement from its ratepayers. A regulatory environment that leads the bank to question whether CPS can recover its costs will affect the bank's decision about financing. The bank also will consider CPS' history—for example,

[20] This would represent, for example, a medium-sized coal plant or a particularly large wind plant of around 400 MW to 450 MW.

its record of negotiating or attempting to renegotiate existing power contracts. The CPS/WDC agreement must, like any legal contract, be practical for all parties, enforceable and not likely to change.

Revenue Streams. Commercial One considers various revenue streams when it examines the underlying financial condition of the project and the company. These revenue streams differ in various areas of the United States because restructured and traditionally-regulated states differ significantly. The revenue streams include energy, renewable energy certificates (in the case of a renewable energy power plant), ancillary services and capacity payments.

- *Energy.* Commercial One regards the price per kilowatt-hour of electricity in the power purchase contract as a primary indicator of the project's ability to meet its financial obligations. Commercial One examines the risk that the price will change substantially in the future and the ability of the revenue stream to meet the financial obligations of the project. In nonrestructured markets, this is the primary source of revenue for the project. Commercial One also considers other terms of the power purchase agreement, including whether the price is fixed and for how long, or whether the price varies over time according to some external factors.

- *Renewable energy certificates.* If WDC's plant is a wind or other renewable energy project and the state allows the use of RECs to satisfy renewable energy requirements, WDC may be able to sell renewable energy credits. For each megawatt-hour of electricity the plant produces, WDC receives a certificate to prove it delivered that power into the grid. It can sell that certificate to utilities or others that need them to meet renewable energy obligations. WDC receives more money for the certificates when they are scarce (there is not enough renewable energy supplied in the marketplace to meet the demand for it, perhaps because several states' renewable portfolio standards have recently come into force and the supply is not yet able to meet the demand). When the certificates are commonplace or oversupplied, they are worth far less, and WDC receives less when they are sold. Commercial One considers the REC market with some skepticism because the market is new and WDC is unable to guarantee a long-term revenue stream from sale of the RECs. A long-term revenue stream might come from a long-term contract with a utility or other entity to buy a certain number of RECs each year. Revenues from REC markets are relevant to both restructured and traditionally-regulated markets.

- *Ancillary services.* In restructured markets, Commercial One also examines revenue streams from ancillary services. (Ancillary services are a category of services that some power plants provide to keep the power grid running efficiently and reliably. Voltage support and spinning reserves are two such services that keep the power flowing efficiently on the grid and help power system respond quickly to changes in load or in output from other power plants.) Often, these revenue streams will be lower than the revenue stream for energy, although this is not always true. The power plants may or may not sell products into the ancillary services market. In the case of a wind power plant—since wind facilities may not always be physically able to provide ancillary services to the market—it may not sell ancillary services. A gas, coal, biomass, geothermal or nuclear plant, however, might sell several ancillary services. The RTO is the ancillary service buyer in those markets with RTOs, and utilities may be ancillary service buyers in other markets.

- *Capacity payments.* In some restructured markets, power plants are rewarded with capacity payments for their availability. The payments help ensure that the grid has enough backup power reserves to meet unusual needs such as those resulting from a summer spike in demand from air conditioners or the sudden outage of a large power plant. Baseload plants such as gas, coal, biomass, nuclear or geothermal facilities could earn capacity payments. Due to the intermittent nature of the wind supply, it would be difficult for wind farms to earn capacity payments at the same level as a natural gas or a coal fired power plant. Some RTOs have not yet set policy about how much, if any, capacity payment they will pay wind plants. In the eastern United States, PJM has determined that it will give wind plants a partial payment of approximately one-fifth the amount it gives a more traditional fossil resource, based on the wind plants' real availability at peak times when the power system most needs the output.

  The bank considers more than just the current level of the capacity payments. It considers how likely it is that the method used to calculate the payments may change in the future, for instance. Uncertainty about the structure of capacity payments leads the bank to question how much it can rely on them when it compiles its financial projections for the project; the payments may be discounted considerably when they are uncertain.

Legal and Regulatory Environment. Commercial One examines the regulatory climate in which WDC proposes to build its power plant. Mid-stream changes in some government policies—especially any changes that might affect the revenue stream from the power purchase agreement—may cause lenders to be reluctant to base any loan or investment on a promise of a government incentive or regulatory requirement.

This is an important aspect of financing any investment in the power industry, whether through the project or the corporate finance process. Uncertainty makes investors uncomfortable. In regulated states, utilities will see poor financial ratings if their regulators refuse to allow them to put their costs into retail rates so they can earn a reasonable return on investments. Of course, if regulators refuse to let a utility recover its costs, it is likely an indication of other, more significant problems that also are likely to alienate investors. The same is true for utilities in restructured states that have signed agreements to buy power from independent generators and resell it to retail customers. In such a circumstance, a perception that the regulatory commission would be unlikely to allow them to place the cost of the purchased power contract into rates would cause that utility's ratings to drop.

An uncertain legal and regulatory environment has other detrimental effects. If WDC were a wind developer, it would be able to take advantage of a federal production tax credit so long as its turbines are in operation before the tax credit expires; the tax credit is guaranteed for 10 years. Another payment that goes to public utilities—the Renewable Energy Incentive Payment—is set at the same level as the production tax credit. It is subject to the whim of annual appropriations in Congress, however, so investors essentially discount its value when they consider the financial condition of individual projects or the companies behind them.

Technology. Commercial One hires independent engineers to examine the technology and its ability to produce power, given the wind resource assessment. In the wind energy case, WDC probably would select wind turbines made by a major turbine manufacturer. Commercial One would determine whether the manufacturer's turbines operate with a proven performance record in similar climates. Commercial One also finds that the wind resource studies appear reasonable and that the amount of wind at the site will, indeed, be sufficient to produce power. Were WDC using coal or gas, Commercial One would consider the performance of the gas or coal technology to be used. New, unproven technologies are more difficult to finance than are more traditional technologies. The bank considers the history of the technology with the general view that proven technology is far better than new technology, even if the new technology has been proven in the laboratory and field tested.

A utility—as opposed to an independent power producer such as WDC—also could build a new technology power plant, such as an IGCC plant. The financial community might not consider the individual power plant except to understand how that plant affects the overall risk and financial profile of the utility. A large investment in new technology might put a utility at higher risk; for example, regulators might refuse to grant the utility cost recovery for the plant. Thus, utilities are particularly focused on whether they will be able to recover their costs for investments in new, less proven technologies.

Regulators in some regulated states also take advantage of other methods to encourage new generation infrastructure by allowing accelerated depreciation of the new infrastructure (leading to faster cost recovery) or by allowing the utility to recover its costs more quickly by adding costs to the rate base before the plant is actually completed (such costs are known as construction work in progress).

Experience and Reliability of All Parties. Although project finance does not rely explicitly on the credit of the developer, Commercial One still makes an important qualitative judgment about whether WDC appears ready and able to build the project and whether the project operator also has a financial incentive to continue with the project. One banker interviewed for this effort notes that she reflects on whether she could comfortably introduce the loan applicant to her chairman. If she did not feel comfortable with that idea, she would be less inclined to invest in the developer's project.

Milestones and Security. Commercial One considers the milestones for completion of various tasks and the security payments that the contract requires as a way to manage risk. The bank feels comfortable only if those milestones appear reasonable and will not deter the project from meeting its financial obligations. As with the other provisions, a difficult schedule of project milestones or large security payments to the utility will make Commercial One view the project as more risky. Additional risks translate into higher interest rates in the financing contract.

Commercial One would like to have complete confidence that WDC will collect the revenue it has been promised. Any event that might interfere with receipt of the predicted payments is a source of risk to Commercial One. If certain events can diminish the expected revenue, then WDC can take steps to ensure that either the events will not occur or that the project's economics are not affected by the event. If, for example, performance tests are required by the utility as a prerequisite to full payments, WDC can incorporate redundancy into the equipment design and provide a reserve against operational contingencies that would lead to the failure of a performance test. Similarly, if power revenue can vary with the utility's avoided cost, WDC may need to set a minimum rate by negotiating a contract floor price or attempt to otherwise contain pricing variability.

In essence, WDC will need to insure against the events that could lead to diminished revenue. The cost of such insurance is not necessarily related to the cost to the utility of the event. Any remaining uninsured events represent risks to Commercial One. For higher risks, such as the use of new technology, Commercial One will demand a higher interest rate as a risk premium. Some major risks are uninsurable and unacceptable and may result in a project that Commercial One will not finance.

Fuel Source. WDC presents its wind, solar, biomass, geothermal or other renewable energy resource assessments to Commercial One as proof that the renewable resource is adequate. Commercial One, in turn, gives those assessments to its independent engineer, who examines them in detail. If the engineer agrees there is enough resource to produce electricity, Commercial One will continue to structure a deal. In the case of fossil technologies, sponsors must show they have a long-term gas or coal contract or an adequate supply of wood or other biomass.

Permits. Developers must secure all permits possible before the plant begins operating. Investors or lenders will not invest in a project without some assurance that the developer has secured the necessary permits to build and operate the facility.

Developer or Sponsor Financial Interest in the Project's Success. Commercial One is considering whether to entrust millions of dollars to WDC over a multi-year period. Despite power sales contracts, secure energy supplies and the permits, lenders like to see that the developer has a financial incentive to keep the project in operation and to meet the financial projections upon which the loan is proffered. That incentive might be in the form of an equity interest in the facility—an investment of the developer's own money in the power plant, for example.

Construction Costs and Site Lease. Commercial One considers the developer's ability to build a working power plant within the proposed budget. A prevalent problem with power plants—particularly those that use new technologies—is that they do not work as they were intended and may require additional capital investment to correct problems. This additional capital comes from lenders or equity sources, but at higher financing costs for the project. Commercial One also determines that WDC has secured the rights to build on the land.

Other Risks. Commercial One appraises the project's risks; for example, will there be significant community opposition to building the power plant?

If Commercial One finds that the project can meet the financial projections, that the wind resource studies are reasonable or fuel supplies are assured, that the technology will work, and that the risks of the project are not too great, it decides to proceed with financing. At this point—signing the contract—Commercial One asks WDC to provide an initial commitment fee. Commercial One also asks WDC to provide copies of draft and final engineering studies, construction contracts, and operation and maintenance contracts.

Finally, Commercial One is satisfied with the project. The two parties close their agreement. The agreement includes many points, but a key attribute will be control of Commercial One's exposure. WDC and its contractors want to make money. This will be facilitated by dictating when and to whom payments are to be made. Some key points of this agreement follow.

Spreads. Commercial One expresses the interest rate on the loan as a spread over some generic but widely accepted interest rate. The spread is the number of basis points above a certain published interest rate. This published interest rate might be the London InterBank Offer Rate (LIBOR), the rate at which banks can loan money to one another on the international market. The spread will reflect the level of risk the bank feels it is assuming. Projects with greater risk typically have greater spreads. For example, a LIBOR rate (4 percent) plus a 2 percent spread (200 basis points) would equal 4 percent plus 2 percent, or 6 percent. A riskier project might have a spread of 250 basis points, or an interest rate of 6.5 percent in this example (4 percent plus 2.5 percent).

Equity Requirements. Commercial One asks WDC to raise 20 percent of the necessary financing from equity investors. The equity amount that senior lenders require will vary according to the level of project risk determined by the bank. The amount of equity that senior lenders require also varies over time. Equity investors consider most of the same issues as banks when they decide to invest in the project. Equity investors tend to demand a higher return for their money than lenders, but they do so because their funds are at greater risk than the bank's funds; debt is repaid before other obligations in case of a bankruptcy.

Reserves. Reserve accounts are used to cover the risk that a project might temporarily be unable to meet its financial obligations. In this case, Commercial One asks that WDC pay into the reserve account by drawing upon the loan received when the project began operation. Reserve accounts also can be filled through project revenues. The greater the risks to the lender, the greater the reserve requirements will be.

Coverages. Commercial One asks that the WDC wind power project maintain a certain ratio of cash flow[21] to debt obligations. If the project falls below that ratio, Commercial One would be warned that the project is performing poorly. Consistent problems will bring Commercial One's "workout department" (the bank's group in charge of working through difficult or nonperforming loans) to meet with WDC and restructure the loan. The workout department deals with loans and projects that are having trouble meeting their repayment obligations. Riskier projects are required to maintain higher coverage ratios.

Distributions to Equity Investors. The loan agreement usually dictates when and under what circumstances WDC can distribute cash to the project's equity investors.

At closing of the $500 million construction loan, WDC is responsible for paying a bank fee and the bank attorney fees. WDC also is responsible for paying for the bank's engineers to examine the project. WDC, like many developers and sponsors, pays these upfront fees with the first draw on its loan.

WDC contractors then begin work on the project. A monthly construction progress report is prepared by WDC. Commercial One engineers review the

---

[21] Cash flow is defined here as earnings before interest, taxes, depreciation and amortization.

report and WDC's progress and approve a monthly draw on the loan until the agreed-upon completion date for construction. This can be up to three years; for a wind project, it is more likely between one and two years. At the end of the construction loan period, Commercial One will have invested $500 million, or 100 percent of the financing. WDC now must repay the full value of the construction loan.

Security. The loan will be secured by a pledge of all tangible and intangible assets associated with the power plant—all property, the plant and plant equipment.

The Term Loan.[22] WDC repays the construction loan with a $400 million term loan from Commercial One[23] and $100 million from its equity investors. In essence, 80 percent of the three-year construction loan is converted to a term loan. The trend in today's market toward short-term power purchase commitments will make it more difficult for many power plant developers, which benefit from long-term contracts, to amortize their capital costs and to secure financing.

Commercial One now will receive quarterly payments from WDC. The equity investors will receive cash distributions periodically, but only after Commercial One, the company operating the project, any reserves, and the subordinated lenders have been paid. Typically, the equity distributions will be made only if the project is providing a coverage ratio of 1.25 or more. The equity investors assume the greatest risk in the project, but also could receive the highest returns.

This project financing has given WDC $500 million over 18 years from a combination of equity investors and a senior lender. Other, more complicated, project financing can involve numerous lenders with varying levels of priority and several equity investors, but the processes are similar.

---

[22] The term loan also is referred to as take-out financing or permanent loan.
[23] It is typical for the same lender to offer the construction loan and the term loan.