Bilateral Contracting in Deregulated Electricity Markets

A Report to the American Public Power Association

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1. Introduction

A bilateral contract in an electricity market is an agreement between a willing buyer and a willing seller to exchange electricity, rights to generating capacity, or a related product under mutually agreeable terms for a specified period of time. Most economists agree that such arrangements are crucial to the functioning of electricity markets, because they allow both parties to have the price stability and certainty necessary to perform long-term planning and to make rational and socially optimal investments.

In jurisdictions with traditional regulation of electric utilities, just about all electricity is procured either through self-supply or through bilateral arrangements; in fact, these utilities operate in what are often referred to as “bilateral” markets.[1] In such markets, electricity providers build and own their own generating units or do so jointly with other utilities, form long-term purchase arrangements with independent facility developers, or engage in economy transactions with neighboring utilities to their mutual benefit. Thus these utilities can optimize their generation mix and limit their exposure to fluctuations in fuel prices, construction costs, regulatory requirements, and other economic factors over time by managing their portfolios of self-owned resources and power purchase arrangements.

In market regions administered by Regional Transmission Organizations (RTOs), many states have implemented retail access programs. In such programs, regulators have discouraged retail electricity providers from owning their own generating resources. In some cases they have even been barred from engaging in long-term contracts to hedge against short-term price fluctuations, under the assumption that such contracts would “lock in” high prices and prevent the benefits of competition from accruing to consumers.[2] These markets are dominated by organized spot market transactions centrally administered by the RTO, through which electricity can be purchased hourly on a real-time or day-ahead basis. However, long-term contracts yield recognized benefits in RTO-administered markets in terms of risk management, long-term price and supply certainty, and supporting new resource development. Ideally, the spot markets should be the marketplace of last resort for retail providers who have an obligation to serve load, providing little more than a balancing market for meeting deviations from forecasted load. In reality, much of the power sold for each hour is traded in these spot markets. Under these circumstances it is the anticipation of spot market prices that drives pricing terms for the vast majority of bilateral arrangements. As discussed below, if sellers have market power in spot markets they will have the benefit of this market power in bilateral markets. Thus the impact of spot market dynamics on the environment for bilateral negotiations is profound. No less important is the role of healthy bilateral markets in mitigating the less benign aspects of spot markets. As more purchasers rely more heavily on long-term contracts, spot market opportunities for sellers diminish,

[1] For example, in FERC’s recent technical conferences under Docket AD07-7, FERC organized the issues into those concerning “bilateral” (regulated) and those concerning “organized” (ISO-controlled and spot-market-driven) electricity markets.

[2] For example, under California’s restructuring process retail providers were required or strongly encouraged to purchase all electricity in the spot market, under the assumption that any long-term contracts would become uneconomic as competitive pressures caused wholesale prices to fall. This turned out to be an extremely costly mistake when wholesale prices skyrocketed in the winter of 2000-01 and 100% of the non-municipal load in the state was unhedged.

limiting market power and lessening the impact of short-term volatility, and likely pushing spot prices closer to short-run marginal cost.

In the sections that follow, we explore bilateral contracts and why they are valuable to the proper functioning of electricity markets, including RTO-administered markets, and how they should ultimately provide benefits to consumers. We explore the experience with bilateral contracting in RTO-administered markets to date, although this investigation is hampered by the confidential nature of most detailed information relating to bilateral transactions. We further investigate the obstacles to bilateral contracting in RTO-administered markets and what roles various entities, including the Federal Energy Regulatory Commission (FERC), the RTOs themselves, and state public utility commissions, could and should play in addressing them.

Many of these issues are strongly debated, and the positions of the market participants vary widely, depending at least in part on each participant's role in the electricity marketplace. Most recently, these questions and others have been addressed by a number of market participants in response to FERC's Advance Notice of Proposed Rulemaking (ANOPR) and technical conferences in Docket No. AD07-7-000 (Wholesale Competition in Regions with Organized Electric Markets). We draw broadly upon these comments in this study. In addition, we distinguish among the various types of contractual arrangements that fall under the broad heading of "bilateral contracts," with particular attention to those that provide the various benefits of freely-entered, long-term purchase arrangements. Finally, we provide perspective on actions that FERC, RTOs and states could and should be taking to provide a more supportive policy environment for the types of bilateral contracts that are most beneficial to developing healthy, competitive electricity markets.

Summary of Conclusions

Our review indicates that while bilateral contracts are widely recognized as crucial to the functioning of truly competitive electricity markets, RTOs have failed to create an environment conducive to the vigorous, competitive, long-term bilateral contracting that would provide the most benefits to consumers. The primary obstacles we find are related to risk asymmetry: buyers face greater risks than sellers in waiting to transact in today's spot markets, so sellers can charge a risk premium for bilateral contracts.

Thus we find that transactions in the organized markets are dominated by the spot markets, even in cases where much of the energy used to serve load is not directly procured through the spot market. We find that regulatory uncertainty, lack of adequate long-term transmission planning, and lack of long-term Financial Transmission Rights (FTRs), have all impeded sellers' willingness to transact on a bilateral, long-term basis, while the lack of risk associated with transacting in the spot market has limited sellers' incentive for transacting bilaterally. We find that the risk of penalties for institutions and individuals that "guess wrong" leads to a disproportionate risk for sellers who enter into long-term contracts, and for buyers who do not. As a result of this risk asymmetry, the gap between what buyers are willing to pay and what sellers are willing to accept under long-term contracts has been too great to bridge in many cases.

Our other observations are as follows:

- **Overreliance on spot markets has resulted in windfall profits for owners of existing generation, distorting the bilateral market.**

In the spot energy markets, the price of power is set based on a clearing price determined by the most expensive bid from those generators that are needed to meet instantaneous load; today this is often the price of a gas-fired combined cycle or simple-cycle unit. This dynamic has resulted in windfall profits for existing, amortized, low-cost resources such as coal and nuclear units. There is no incentive for the owners of these resources to sell their output at any price lower than what they would expect to receive on average in the spot market, even if this far exceeds the level required to recover their embedded costs. As a result, as existing contracts on amortized assets have expired, an increasing proportion of power transactions have moved into the spot market greatly increasing the revenues for such resources, or have been renegotiated under terms which reflect spot market prices far in excess of their production cost.

- **The potential for bilateral contracts to help stabilize retail prices and minimize retail supply costs is not being fully tapped.**

Retail auctions requiring multi-year laddering of retail service provider contracts, such as those in New Jersey and Maryland, have helped to mute large interannual swings in the cost of service. However, there is no evidence that power is being procured in these markets on a longer-term basis than required for the auctions. Further, there is evidence that consumers are paying a significant price premium for this stability.[3] This approach is clearly not realizing the potential for a true diversity of contract durations.

- **Retail SOS customers are protected from some wholesale electric energy price volatility, but are still at risk.**

The load serving entities responsible for Standard Offer Service (SOS)[4] typically acquire a substantial portion of their electric energy requirements under fixed-price contracts selected through periodic auctions. The pricing of SOS is typically designed to prevent sudden sharp changes for consumers, using a multi-year laddering approach. Thus the impact of changes in supply prices on SOS retail prices is typically phased-in.

However, if an auction happens to coincide with, or occur shortly after, a spike in spot electric energy prices, the prices bid into that auction will reflect that price. For example, in 2005 Hurricanes Katrina and Rita resulted in extremely high natural gas prices. This in turn led to extremely high prices in electric energy spot markets. The bids submitted in the auctions during that period reflected those extreme spot market prices. That exposure could be reduced by reducing the portion of SOS supply sought in any single auction, by holding more auctions during the year, and by seeking bilateral contracts of various durations longer than 3 years in addition to the common 1 to 3 year term.

In considering a time-laddered portfolio such as that required by certain state SOS protocols, it is important to recognize that the average price over time of electric energy

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[3] Rose, K., "The Impact of Competition on Electricity Prices: Can We Discern a Pattern?" Presented to the Harvard Electricity Policy Group, Forty-Ninth Plenary Session, Los Angeles, December 6, 2007.

[4] SOS is a term generally used to describe the supply service provided to retail customers in restructured markets who have not chosen to acquire their supply from a competitive marketer. Other terms for this service include basic generation service, default service and provider of last resort service.

acquired under short-term (three years or less) bilateral contracts will reflect the expected average price of electric energy acquired from the spot market, and are likely to include a risk premium and other adders. However, it is possible that load serving entities may be able to acquire electric energy at a price closer to average production cost under long-term (longer than five years) bilateral contracts with suppliers who wish to develop new resources.[5] Shorter term bilateral contracts are more likely to limit participation to bidders with existing resources and short lead time plants that are already under construction during the contracting period.

- **Bilateral contracts have been used to support some new resources, including renewable resources.**

Our research has shown that a large number of smaller resources, developed by smaller entities, *have* been able to finance their projects on the basis of long-term contracts. This includes developers of renewable resources. In this case both parties have a strong interest in transacting bilaterally, and these resource developers will agree to prices that enable them to get the project financed and to earn an acceptable rate of return but require them to forgo the opportunity to profit from scarcity rents in the wholesale market.

In fact, none of the renewable energy developers who responded to FERC's request for comments under AD07-7 suggested that they had any difficulty in finding long-term buyers for their output. One reason may be that there is much less risk in this type of contract, as neither party bears the risk of unknown future fuel and emissions costs. Retail marketers, both SOS utilities and competitive retailers, in most deregulated states are required to procure a certain portion of their energy from renewable sources (or at least to purchase Renewable Energy Credits, also called RECs) so they have a strong interest in locking in a stream of renewable power, in addition to price-stable power, over the long term. At the same time renewable resource developers can be assured a long-term, reasonable return on their investments.

This area of success for bilateral contracting in deregulated markets suggests that when the benefits are mutual and symmetric, suppliers and purchasers can come to terms on mutually acceptable prices for long-term bilateral energy contracts.

- **Use of bilateral contracts to support development of new generation resources has not been sufficient to meet reliability needs.**

Despite the apparent desire of some large customers and public power entities to enter into long-term contracts, there has not been a sufficient incentive to bring needed capacity on line. This has particularly been the case with development of base load capacity. At the same time, contracts that support retail service auction obligations are far too short in duration (one to three years) to provide new capital-intensive capacity with the revenue guarantees necessary to support favorable financing terms. A number of RTOs and ISOs have tried to address this issue by instituting forward locational capacity markets. While these markets have resulted in yet more windfall profits for owners of existing, profitable generating resources at a cost to consumers of tens of

[5] In an idealized competitive market, the long-term wholesale market price reflects the projected all-in cost of a new resource. In today's electricity markets this appears to be more of a lower bound on future prices.

billions of dollars in increased capacity costs, they still do not provide the long-term assurance of revenues which would be needed to adequately support generation investments. As a result, investment in needed capacity still lags load growth in many areas.[6] As with the energy markets, the high prices in the capacity auctions make it *less* likely that generation owners will be willing to enter long-term contracts for their capacity on anything close to a cost basis, if they can avoid it.

In this area there may be a ready opportunity for improvement. Because of the very high prices in the capacity auctions, states have a strong incentive to procure (or require utilities to procure) generating capacity and load-management resources on a long-term basis on consumers' behalf. In addition to providing consumers with the least-cost resource (generally demand management), this will decrease the market power of sellers and force them to negotiate contracts on something closer to a cost basis. While sellers of existing capacity may not be willing to forgo the benefits of the energy and capacity auctions, state commissions can order the procurement new supply and demand resource on a long-term basis, and order that such resources be bid into the capacity auctions at cost. This would have the impact of lowering capacity prices on *all* resources by both mitigating supplier market power and by increasing available low-cost resources in the market. As an example, in California the IOUs who are currently providing Standard Offer Service are guaranteed cost recovery for procurement through Requests for Proposals (RFPs) for 10-year contracts. In this case, if retail choice or community aggregation results in movement of retail load the capacity will be allocated to the new supplier to follow the load and the IOUs can sell the energy on the spot market. Over the long term, this sort of arrangement has the potential to restore some of the average cost pricing benefits of regulated markets.

- **The potential for bilateral contracts to help mitigate market power is not being fully realized.**

The existence of a robust bilateral market can help to mitigate market power for both bilateral and spot transactions in energy markets, by giving buyers more flexibility in structuring their supply portfolios. However, for this to occur there has to be a sufficient incentive for both parties to transact in the bilateral market, symmetry of risk in the spot markets, and as a result comparable judgments of an acceptable price at which to transact bilaterally. As long as sellers can be confident of high profits in the spot markets for both capacity and energy, these conditions will not be met. Indeed, the new capacity markets essentially guarantee cost recovery and more to all resources, with windfall profits to many. Under these circumstances, only the buyers bear risk by waiting to transact in the spot market. Further, buyers and individuals within buying organizations bear a much greater risk of being held to account for misjudgment in making long-term contracts than in failing to do so when it would have been prudent. Because of all of these risk considerations, the potential market power mitigation benefits have not been realized.

[6] See for example, Wilson, James, "Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM)," report to the American Public Power Association, March 2008.

2. Bilateral Contracting in Deregulated Electricity Markets

This section provides the background to our discussion of bilateral contracts in deregulated markets. It presents an overview of the operation of deregulated electricity markets and the value of bilateral contracts to the proper functioning of those markets.

A. Deregulated Electricity Markets – Wholesale and Retail

To frame this discussion of restructured electricity markets, it is helpful to introduce the various types of market participants in RTO-administered electricity markets and the ways in which they can transact with each other to ultimately deliver power from generation owners to load. An idealized schematic of this process is shown in Figure 1. In this figure, generating companies and demand response providers are shown in tan, marketers in gold, retail providers in orange, distribution utilities in gray, and retail end-use customers in blue. In general, the sellers on the wholesale side are unregulated generation owners or demand response providers, although these may be affiliates of any of the other participants in the market. Marketers play a role in risk management and bundling; they can be both buyers and sellers of electricity under various contractual arrangements that are intended to reduce risk for other entities.

In general, the buyers are retail providers. In theory, these can be either default service providers, which may be winners of retail auctions to provide standard offer service (SOS) in states with retail auctions. They can be also competitive retail providers (that is, non-SOS) who market directly to customers. In practice, very few such competitive providers have materialized in states that have opened the doors to retail competition, and very few customers have opted to switch from their default provider. Retail auction winners sell through the distribution utility, which is generally the former vertically-integrated utility for a given service area and is still the name on the bill for standard offer customers. However, this utility is no longer actually responsible for generating or purchasing power to serve its customers; it merely delivers and bills for the power that the standard offer provider supplies. In addition to these retail providers, buyers can include municipal utilities or neighboring utilities that are short of self-supplied power, or large customers who shop directly in the wholesale market.

As may be seen in Figure 1, in theory all of these buyers have a number of choices for how to transact for power and manage their risk. They can simply rely on the spot market and take their chances with hourly prices; they can enter into long-term contracts directly with generation and demand response suppliers or with wholesale power marketers; purchase options for hedging future spot purchases instead of contracting for physical delivery of power; or they can build and run their own generating plants. If all of these possibilities were equally available, one would expect the prices associated with all of these options to converge, at least as a long-term average. The price to which they would converge should be based upon the long-run cost of self-supply. This is because in a competitive market, buyers should hold the implicit threat that they can always build or buy to procure power at this price if market purchases prove too costly.

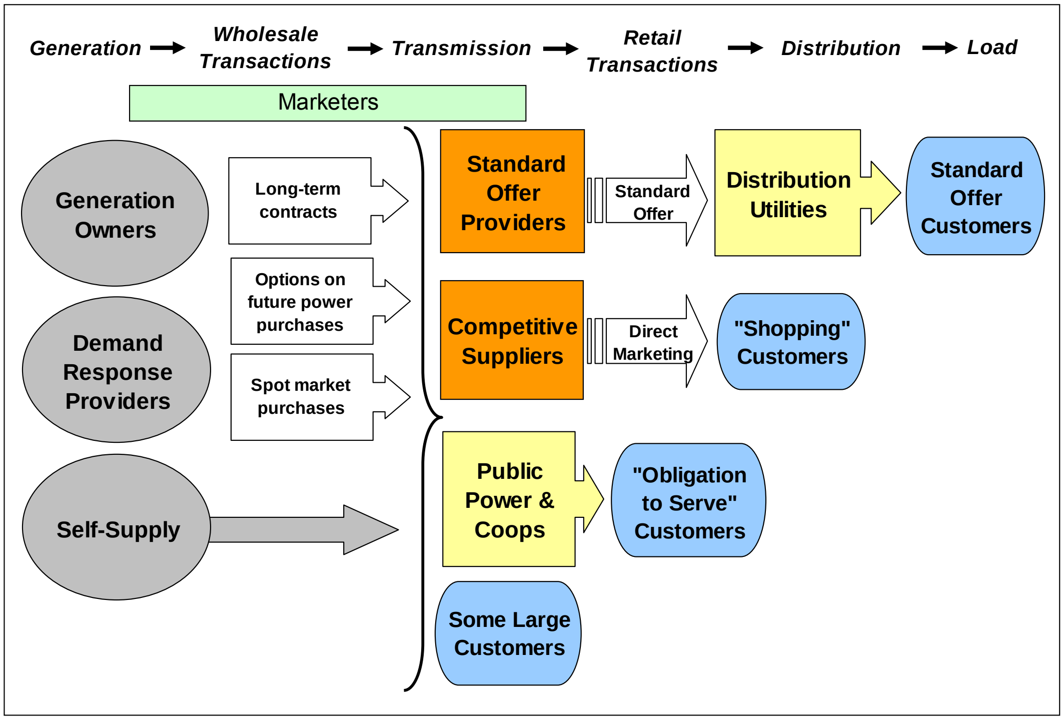

Figure 1. Schematic of deregulated wholesale and retail electricity markets showing various contracting options for supply resources (generation and demand response) to reach load.

Any discussion of the design and operation of deregulated electricity markets must distinguish between wholesale electricity markets, which are subject to federal regulation, and retail electricity markets, which are subject to state regulation. In, the left side of the schematic depicts the wholesale market and the right side depicts the retail market. The institutional and contractual arrangements, which are the focus of this paper, provide the interaction between wholesale and retail sides of the market.

Wholesale

FERC implemented a series of major changes in the structure, operation and regulation of wholesale electricity markets at the Federal level in the 1990s. These changes required the functional unbundling of wholesale generation from transmission, allowed certain electric energy and capacity prices to be set by the market instead of on a cost basis, and required transmission to be provided on an “open-access” basis at regulated rates. FERC created the RTOs[7] to oversee the provision of open-access transmission, to set reserve requirements to ensure an adequate level of capacity and to administer one or more spot markets for electric energy. In current, “day two” organized markets, most power is bought and sold one day in advance (Day Ahead, or DA) of electricity production and any imbalance between DA transactions and real-time loads is transacted in the Real Time market.

Following the restructuring of the wholesale electricity market, futures markets have developed for electric energy to provide buyers and sellers with some opportunities for managing electricity price and cost risk. These opportunities include such financial

7 Some Independent System Operators (ISOs) also play the role of RTOs

instruments as monthly futures contracts for on-peak and off-peak electricity transactions at various delivery locations throughout the United States, and options on such monthly futures contracts. While such futures market contracts are theoretically available for up to five years into the future, the volumes traded in the outer years are negligible in today's RTO markets and the prices give little indication of likely conditions more than one or two years into the future. Within RTO markets in general, the prices in futures market contracts are driven largely by expectations regarding future prices in the wholesale spot electric energy markets. These in turn are influenced by projections of fuel prices, capacity cost and availability, environmental regulations, and other variables.

Retail

At the state level, a large number of states have followed the Federal lead and restructured their retail electricity markets. Under the new structure for retail markets, the role of utilities subject to state regulation[8] no longer includes the generation of power and is limited to providing transmission and distribution service at regulated rates. Those utilities were required to exit their traditional electricity supply function, with the expectation that customers would acquire that service at competitive prices from retail marketers.[9] However, in recognition that a robust competitive retail market may take some time to develop, each state that initiated retail competition established a "default," "basic" or "standard offer" electricity supply service[10] for retail customers who did not immediately migrate to a competitive provider. Standard offer service was typically designed to acquire supply under bilateral contracts from wholesale marketers. Today, many states administer periodic auctions or RFPs for standard offer providers to procure supply contracts, with the contracts usually limited to terms of three years or less.

The actual operation of deregulated retail markets has proven to be somewhat different than expected by many proponents of deregulation. Only a relatively few large- usage retail customers, primarily in the industrial, commercial and institutional sectors, have ended up "shopping" for power from competitive suppliers. The majority of medium and small usage retail customers, including almost all residential customers, have remained on standard offer service. For example, in 2006, approximately 80 per cent of the electricity consumed in New Jersey was acquired under that state's standard offer service ("Basic Generation Service," or BGS) while only 20 per cent was acquired from retail marketers.[11] Because most of those purchasing power from competitive suppliers are larger customers, those purchasing power from alternative suppliers represent fewer than one percent of all customers.[12]

[8] Note that certain types of utilities were exempt – such as municipal utilities.

[9] Retail marketers, together with other entities that serve load such as municipal utilities, cooperatives, and some distribution utilities, are collectively referred to as "Load-Serving Entities" or LSEs.

[10] Note that the name of this service varies by state; in this document we will generally use the term "standard offer service" to refer to the default provider of retail electricity.

[11] Energy Information Administration, Electric Power Annual, *Retail Sales of Electricity by State by Sector by Provider (EIA-861)*

[12] Energy Information Administration, New Jersey Electricity Profile, Table 9. Retail Electricity Sales Statistics, 2006, http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept09nj.xls.

B. Role of Bilateral Contracts in Deregulated Electricity Markets

As depicted in Figure 1, retail providers, municipal utilities, and large retail customers operating in deregulated electricity markets areas can acquire their electric energy supply through a few basic instruments: bilateral contracts, spot market purchases, and self-supply.

A bilateral contract, for the purposes of this report, is any contract between a buyer and a seller for the purchase and sale of an electricity-related product at negotiated terms including duration, price, delivery location, times of performance, and any other terms which may be deemed applicable. An electricity-related product may be electric energy, capacity (including demand response), ancillary services or some combination of those.[13] In this study we focus primarily on bilateral contracts for energy and/or capacity.

A purchase from the spot market provides supply for a period of up to one day, and involves no negotiation between the parties. In these RTO-administered markets all parties who wish to either sell electricity on the delivery day, or buy electricity on the delivery day, submit their price and quantity offers and bids. The entire market settles simultaneously based on the output of a computer model that selects the lowest priced resources (based on the owners' bids) needed to meet load, given transmission constraints, usually following an algorithm known as Locational Marginal Pricing (LMP).[14] The resulting hourly locational market prices are determined by the price bid by the marginal supplier selected through this process.

The final alternative for retail providers to meet their obligations is through self-supply. It is this option that should, in theory, control the market power of bilateral contract sellers, as well as ultimately keep spot market prices for energy and capacity to cost-based levels. While this option has always been a primary means of procuring energy in regulated markets, it is far less common in deregulated markets. In fact, one of the primary goals of deregulation was to mitigate or eliminate the structural market power of generation in vertically integrated utilities in order to foster competition in this area. However, retail providers can still self-supply either generation or demand management resources in deregulated states. In most cases today, self-supply of demand management services is the least-cost resource option for retail providers. Unfortunately, numerous structural obstacles beyond the scope of this study have prevented the full implementation of this resource option. Whether the development of self-supply in the energy and capacity markets will ultimately reduce procurement costs for those products remains to be seen, but it does not appear to have done so to date.

In regulated markets, self-supply and bilateral contracts are the primary instruments through which electricity is bought and sold. In these markets there is no organized

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[13] "Capacity" is a service product which is the ability to generate power (or reduce demand) when needed, and is sold separately from electric energy itself. Similarly, "ancillary services" is a phrase which refers to a range of similar products which are also not energy, but which facilitate the function of the electric system and the reliable provision of energy when needed.

[14] The LMP system and some of the implications for this approach in deregulated electricity markets is the subject of an earlier Synapse report prepared for APPA, "LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers," available at http://www.synapse-energy.com/.

multiparty electricity auction, so all transactions are on a bilateral basis. FERC refers to those markets in Docket No. AD07-7 as "bilateral markets".

FERC has highlighted the importance of bilateral contracting to maintaining well-functioning deregulated wholesale electricity markets. According to FERC:

> It is important that wholesale sellers and buyers have adequate opportunities to sell and buy electric power through long-term power contracts to allow them to manage their exposure to uncertain future spot market prices. Sellers and buyers should also have the opportunity to sell and buy electric power in the spot market. The Commission believes that it is important for buyers and sellers in organized markets to be able to choose a portfolio of short-term, intermediate-term, and long-term power supplies. Having portfolio choice allows market participants to manage the risk that comes from uncertainty. Forward power contracting by buyers combined with purchases from a spot market with demand response can be an efficient and low-cost way of meeting customer needs because both buyers and sellers can hedge risk as well as adapt to actual real-time supply and demand conditions. Competitive forward power contracting allows many sellers to compete to provide electric service, and greater reliance on long-term power contracting could decrease the incentive for sellers to exercise market power in the spot market if there is reduced opportunity to profit from such action. ANOPR, p. 55.

The value of bilateral contracts lies in their ability to provide willing buyers and willing sellers with a mechanism through which to craft a transaction that meets their specific needs in terms of quantity, price and duration. Because such contracts are negotiated in advance of the delivery period, each party has the option of not entering into the contract if it doesn't like the terms, of seeking another contracting partner, of engaging in self-supply,[15] or of waiting to transact in the spot market. The revenue and cost certainty associated with bilateral contracts presents a number of benefits to sellers and buyers in both the near-term and long-term, as will be discussed more fully later in this report. Ranked roughly from near-term to longer-term, these benefits include:

- **Less volatile retail prices.** If retail providers acquire a substantial portion of their obligation through bilateral contracts at fixed, or predictable prices, their customers will see less volatile retail prices.
- **Mitigation of market power.** If buyers and sellers can choose between a range of supply acquisition options at any given point in time, including bilateral contracts, self-supply, and spot market purchases, it is much harder for sellers to exercise market power. Harder, but not impossible: if there is a reasonable expectation of market power affecting the spot market, and an expectation of a high volume in the spot market combined with limited bilateral contracting

[15] FERC does not consider self-supply as a competing resource option in this passage; this may reflect a continuing bias at the Commission toward "unbundling" of services and purchasing of power from independent providers. However, if competitive sellers can not or will not provide comparable services at a lower cost than self-supply, it is hard to see what advantage such a policy provides in the market.

opportunities, this will affect the terms under which either party would be willing to transact on a bilateral basis.

- **Support for development of new resources.** Developers of major new capital-intensive generation resources typically require a guaranteed stream of future revenues in order to obtain financing for those new resources. Developers can obtain such a guaranteed stream of revenues by selling a portion, or all, of the future output from these new resources under long-term, bilateral contracts. Thus bilateral contracts improve the ability of developers to obtain financing and enable them to obtain more favorable financing terms.
- **More cost-effective, environmentally attractive resources in the long-term.** Bilateral contracts are particularly important to the development of utility-scale renewable resources. These resources tend to be extremely capital intensive, and hence heavily weighted towards up-front costs, since they have no or limited fuel and emissions costs during their operating lives. The absence of fuel and emissions costs makes these resources particularly attractive for hedging future fuel and emissions price risks as part of a portfolio of resources to serve load. However, this avoided risk only benefits ratepayers if they are passed through—i.e., through long-term, fixed-price contracts. In many cases, approval of new environmentally attractive resources hinges on a contract structure that offers this benefit to ratepayers.[16]

Beneath the general concept of bilateral contracting lies a whole range of possible contract terms, and these distinctions are important in considering how well bilateral transactions can serve the purposes outlined above. Short- or medium-term contracts, with durations up to a few years as are often used to supply standard offer service, may help stabilize short-term fluctuations in prices and counteract market power. However, they are unlikely to provide much benefit in terms of supporting the development of new resources. Long-term contracts are crucial for supporting new resources, but they may be perceived as a potential source of stranded costs should market prices ultimately fall below contract prices for a prolonged period. Healthy markets, therefore, should support a range of bilateral contracts of varying durations, enabling market participants to readily hedge their obligations, giving producers opportunities to ensure long term revenue stability, and generally offering the most flexibility for all parties in mitigating risks.

3. Experience with Bilateral Contracts

This section presents a discussion of the various types of bilateral contracts and an exploration, constrained by data availability, of the extent to which each type is being used in today's RTO-administered markets.

[16] For example, in a recent decision on a wind project, the Vermont Public Service Board concluded: "Given the substantial additional benefits of stably priced contracts, we have concluded that, for the Project to promote the general good, we must include a requirement that UPC seek to negotiate stably priced contracts with Vermont utilities that would benefit Vermont ratepayers" (Docket 7156, application of UPC Wind for a Certificate of Public Good, Order of 8/8/2007, p.4.)

A. Range of bilateral contracts

While there are a wide range of possible terms and conditions for bilateral contracts, and hence a myriad of potential categories, two are of particular importance. These are contract duration and contract pricing terms.

Contact Duration

There is no standard definition of short-, medium- or long-term with respect to bilateral contracts. For the purpose of this report we define long-term as more than five years. Contracts of at least this duration (and more likely ten years or more) are required to provide the level of revenue guarantee that developers need to finance new resources, which is one of the most important functions of these contracts. In addition, the ability to enter long-term commitments, and thereby to support development of new resources, should provide LSEs with additional leverage in negotiating prices for all contract durations and with all kinds of sellers. As will be discussed below, this leverage is crucial for combating the exercise of market power in spot markets, as well as in short-term bilateral markets and auctions.

Short- and medium-term contracts (five years or less) also have an important role to play in electricity markets. Their primary function is to smooth out year-to-year and shorter-term price volatility. For example, under New Jersey's Basic Generation Service (BGS) auction, purchases are laddered through annual auctions for three-year delivery, so that the price for any given year is the average of contracts entered into for that year and for the previous two years.[17] Such short-term bilateral contracting is of little use for supporting new resources, however, as they do not guarantee the long-term, secure revenue stream required to obtain financing for electric industry infrastructure.

Contract Price

Another important distinction is between fixed-price and indexed price contracts. Some long-term contracts (known as "tolling" contracts) merely provide the user with the right to convert fuel into electricity, but provide no protection from variations in fuel prices, unless the LSE procures all or a portion of its fuel supply through long-term contracts as well. This can still have numerous benefits, including protecting the purchaser from scarcity rents in times of very high prices, supporting needed resources with a guaranteed stream of revenue, and providing some protection from market power as purchase prices are based on a formula instead of supply offers.[18]

B. When is a bilateral contract not a bilateral contract?

In analyzing the role of bilateral contracts it is also important to distinguish between bilateral contracts negotiated, and freely entered, by both buyer and seller, and those with standardized terms, determined by a market administrator, that both parties are forced to accept. In the latter case the lack of choice can be due to structural factors,

[17] For fuller discussion, see Synapse (2006) report "Energy Portfolio Management: Tools & Resources for State Public Utility Commissions," http://www.synapse-energy.com/Downloads/SynapseReport.2006-07.NARUC.Portfolio-Management-Tools-and-Practices-for-Regulators.05-042.pdf.

[18] An emerging issue of importance for bilateral contracts is the treatment of future carbon emissions costs: Will these be the responsibility of the generator, or flowed through to the buyer?

such as forward capacity requirements or procurement of power for retail customers on standard offer service (SOS) such as the BGS auction in New Jersey. An absence of choice can also stem from political factors, such as the requirement that the California Department of Water Resources quickly secure long-term contracts for energy shortly after the California energy market melt-down of 2000. In situations where one or both parties has no choice but to transact, the market conditions have more in common with spot markets than with traditional bilaterals, and the potential for the exercise of market power is similar to that in the spot markets.

C. Current use of bilateral contracts

Long-term contracts

The data publicly available on bilateral contracts suggest that very few utilities in retail choice states are using long-term bilateral contracts to acquire supply for SOS—they are relying on short-term contracts consistent with the state-mandated terms of the SOS supply obligations. There is some limited use of long-term contracts by LSEs to acquire renewable generation in order to meet renewable portfolio standard (RPS) requirements. In California, 10-year contracts have been used by the utilities to acquire capacity since the market meltdown of 2000, although it is unknown what will replace these arrangements as they expire. However, California differs from other regions because in response to the market failure, new customers to switches to competitive retail access are no longer permitted.

There is some evidence that wholesale marketers may be entering into long-term contracts to support new resources. We reviewed records of power plants added to PJM and ISO-NE from 2004 through 2006, in an attempt to determine how many were supported by bilateral contracts. This analysis suffers from a number of drawbacks: PJM includes both regulated and deregulated states, for example, and some parts of the region joined the RTO only recently. Plants in Ohio and Virginia from 2004 have been excluded from the analysis (Dayton Power & Light, AEP and Dominion joined PJM in late 2004), but other plants included in the review may have already been planned or under construction prior to deregulation. Nonetheless, the examples, details of which are provided in Appendices A and B, prove instructive.

Of the 26 plants considered in PJM, twelve appeared to be supported by long-term contracts, and seven appeared not to be. For the remaining seven we were unable to determine the contract status from public sources. Similarly, of the nine plants considered in New England, six appeared to be supported by long-term contracts and for three we were unable to determine contract status. This appears to indicate that long-term contracts play an important role in supporting new resources.

However, on a MW basis, over 95% of the new capacity in PJM was *not* supported by long-term contracts. In New England there was no evidence for long-term contracts for over 93% of new capacity on a MW basis, so it is difficult to draw conclusions for that market. This suggests that the primary role of long-term contracts is in supporting smaller capacity resources—either renewables or peaking facilities—that may have more trouble securing financing if they have to rely on spot market energy sales as their source of revenues. Larger projects, built and owned by large generating companies, appear to be oriented financially more towards the spot markets which are more susceptible to market power.

Further, we note that all of the new projects in PJM *not* under bilateral contracts appear to be owned by large generation companies, such as PPL, FPL, Dominion, PSEG, and PEPCO. These companies would have more flexibility in financing new generation projects and would be less reliant on bilateral contracts to enable new investments; they would also have the most to gain from any exercise of market power in the spot markets due to their large volumes of available supply on which to profit from any elevation in price.

More recently, both PJM and New England have instituted capacity markets that are intended to provide more revenue security for power plants that are unlikely to recover their fixed costs in the energy market. In both cases the revenue commitment period is just one year, and the market designs are in flux in both markets. This is unlikely to assure banks or investors that such resources are viable in the long-term, so it will not offer a realistic alternative to long-term, bilateral contracts, or meaningfully reduce financing costs for smaller resources. Whether further refinements to capacity markets will ultimately help to fulfill these functions remains to be seen.

Short-term Contracts

Our analyses indicate that LSEs are currently using relatively few, and highly standardized, short-term bilateral contracts to acquire supply for standard offer service. These contracts are generally acquired through periodic auctions or RFPs.

There are only limited public data available on the wholesale marketers' use of bilateral contracts. For example, the PJM 2006 State of the Market Report claims that, "In 2006, 92.8 percent of real-time energy market load was supplied by bilateral contracts, 6.2 percent by spot market purchases and 1.0 percent by self-supply."[19] If this is the case, it would certainly indicate that a healthy short-term bilateral market dominates electricity sales in PJM.

However, closer inspection suggests that this statement is somewhat misleading. PJM defines "spot purchases" as those quantities that a "PJM billing organization" uses to "meet system load." (We understand this to refer to the purchases that an LSE makes directly from the PJM spot market.) In contrast, PJM categorizes all other purchases from the PJM spot market as purchases that are "used to support bilateral sales."[20] The major proportion of these "bilateral sales" is likely sales by retail auction winners to utilities' SOS customers. While these SOS providers are not "billing organizations," they are making spot purchases to meet their (indirect) retail load obligation. The market power, cost, and volatility risk impacts on consumers associated with these sales is exactly the same as if the purchaser were the billing organization itself. Finally, such bilateral contracts are short-term in duration, typically one to three years, such as the BGS contracts in New Jersey.

[19] PJM 2006 State of the Market Report, page 87.

[20] Ibid.

Other bilateral sales in PJM include long-term contracts left over from the divestiture of assets during state deregulation processes, which were often accompanied by buy-back provisions under long-term contracts. Again, this does not necessarily indicate that such contracts are available from new resources, or that the price terms of the contracts confer the desired benefits of long-term contracts to ratepayers. In fact, many of these transition contracts are currently expiring, and the output of the associated resources will most likely be sold at market rates in the future.

4. Benefits of bilateral contracting in electricity markets

Because of the price and revenue certainty associated with bilateral contracts, they can have positive effects on the functioning of electricity markets, and benefit both consumers and producers:

Price stability

If retail providers were able to support a substantial portion of their obligation through fixed-price bilateral contracts, they would be less exposed to the risk of high spot market electricity prices. There is no reason to expect that bilateral prices will differ on average from spot market prices over the long term, but the average price under a portfolio of such contracts will not be subject to the extreme price volatility seen in the spot market. For example, while Hurricanes Katrina and Rita resulted in extremely high gas and electricity prices in spot markets, retail providers were only exposed to these high prices to the extent that they were not hedged with fixed-price contracts. Further, if such portfolio-based contracting is the dominant structure for transacting in an electricity market, this could lower both bilateral and spot market prices by reducing risk on both sides and eliminating opportunities for market power. There are also circumstances under which sellers, particularly developers of new resources, may be willing to offer a discount relative to expected spot market prices, as discussed below.

Along with the price stability advantages, retail providers who purchase a large portion of their electricity requirements forward on a long-term, fixed-price basis do face the risk that wholesale spot prices could be lower than expected, leaving ratepayers with the bill for above-market obligations. An example of this phenomenon is the set of contracts negotiated by the California Division of Water Resources in the wake of the California market melt down of 2000-2001. Because these contracts were negotiated for all of California's electricity requirements at a time of extremely high prices, they soon turned out to be "out of the money," leaving California's ratepayers with a high electricity bill and the state scrambling to renegotiate the contracts. In general, it makes sense for LSEs to rely upon a mixture of contracts with different lengths, including some proportion of spot market purchases, to dilute the risk and to provide price certainty.

Finally, it should be noted that not all bilateral contracts provide the same level of price certainty. In some cases they are indexed to certain market indices, which may be the price of electricity or gas. In this case they still provide some risk management benefits, depending on the terms of the contract. For example, if the contract price of electricity is based on the spot price for natural gas, the buyer will still be exposed to volatility associated with fuel costs but will be protected from having to pay scarcity rents at times when the price of electricity is extremely high independent of fuel prices.

Support for new and renewable resources

New generating resources of all kinds require a significant investment of up-front capital, and the cost of borrowing these funds depends in part on the confidence with which lenders view the project's revenue projections. In addition, some new and needed resources are unlikely to recover their costs selling energy alone, but need to receive capacity payments for full cost recovery. In deregulated markets, developers typically cannot obtain "pre-approval" from a state commission for the costs of such units as was the case in the prior regulatory system, under which utilities could earn a guaranteed rate of return on a capital investment. Pre-selling part or all of the energy and capacity of such resources under long-term contracts provides a solution, guaranteeing that the output of the resource will be sold and sufficient revenues will be forthcoming regardless of market conditions.

The terms of the contract that will most benefit the project developer depend in part on the kind of resource. If the resource is expected to be load-following and to deliver power at a price close to the marginal cost of electricity, it probably makes most sense from the developer's standpoint to index the price of power to a market indicator such as the price of gas. In this case the developer may forgo some of the profit that might be made under very high price scenarios, for example by accepting a discount relative to the market price or agreeing to index only the fuel portion of costs. However, the developer would also not be at risk for an obligation to deliver power below the cost of production. On the other hand, resources such as renewables and nuclear, whose costs are dominated by the fixed investment portion, would not face the same risks, and it may make sense for the developer to agree to a fixed price. The developer can then be assured that the price will provide for an acceptable rate of return while eliminating price risk, at the cost of forgoing any opportunity to profit from scarcity rents.

Again, the optimal strategy for any developer depends on the resource type, requirements for financing, expectations of market price, and what is available from eligible buyers. As for buyers, in many cases it will make sense to rely on a portfolio approach that includes a mix of contracts with varying terms and durations and resource types.

Renewable resources present a special case: characterized by high up-front costs and low running costs, they are immune from variability of most future production cost factors such as fuel prices and availability and emissions prices. These resources have historically carried a higher price than conventional electricity sources, especially when gas prices were much lower than they are today, and are often characterized by non-dispatchable, variable output levels that depend on weather conditions.

Since 1978**,** renewable resources have been supported in regulated markets by the Public Utility Regulatory Policy Act of 1978, or PURPA. PURPA required utilities to buy power from certain qualifying facilities at a price representing the utility's "avoided cost," guaranteeing a long-term customer an attractive sale price for renewable resource developers. However, this purchase obligation is inconsistent with deregulated markets in which competitive forces are supposed to determine which resources are built and how they are financed.

In many markets, a secondary product of renewables is recognized in terms of their environmental attributes, quantified as one "Renewable Energy Credit" (REC) for each MWh of renewable energy produced. These RECs can be sold, either alone or with the plant's electric output. The purchasers could be either utilities or power marketers who are subject to state renewable portfolio standards, or participants in voluntary green marketing programs in which consumers pay a premium to have their electricity use associated with renewable production. Because most of the cost of renewables is up-front capital cost, renewable resources are particularly dependent on long-term contracts for energy, capacity, and RECs. Fixed-price contracts are not unusual for these resources, as they are not at risk of escalating production costs. Suitable contracts for such resources would guarantee delivery either in terms of the output of the resource or in terms of MWh per year,[21] at a price sufficient to deliver an adequate rate of return on the resource.

Market power

Market power refers to the ability of a market participant to raise prices profitably above competitive levels and maintain those raised prices for a significant time. Market power can exist in two forms—vertical and horizontal. Vertical market power can exist where a party controls two related products or services; horizontal market power occurs when a party controls a significant share of the market for a particular product.

Vertical market power

In the electric power industry a party that controls both electricity generation and transmission has the potential to exercise vertical market power. In its efforts to establish a framework for competition in wholesale electricity markets, FERC has placed considerable emphasis on eliminating the potential for vertical market power by separating control of electricity generation from control of the transmission system. FERC's goal has been to make the transmission system accessible to all prospective buyers and sellers, thereby ensuring that incumbent suppliers could not prevent new suppliers from entering the market. This emphasis on open-access transmission is similar to the approach that FERC took when establishing a framework for competition in wholesale natural gas markets.

Following are a few examples of the specific steps that FERC has taken to prevent vertical market power in wholesale electricity markets:

- Order 888 (April 1996) and Order 890 (February 2007) requires all public utilities that own, control, or operate transmission to file an "open-access non-discriminatory transmission tariff."

[21] Both energy and RECs are denominated in MWh of energy production, with one REC being produced for each MWh of energy delivered. Capacity is denominated in MW-month of kW-year of available generating capacity and is not directly related to annual output. Rules for awarding capacity value to intermittent resources such as wind and solar differ among electricity markets.

- Order 2000 (December 1999) asks all transmission-owning utilities, including non-public utilities, to place their transmission facilities under the control of an RTO.
- Orders 889 (April 1996) and Order 2004 (November 2003) establish standards of conduct prohibiting communication between public utility transmission and wholesale merchant personnel.
- Order 2003 (July 2003) and Order 2006 (June 2005) establish standardized generator interconnection procedures for large and small electric generators.

These market structure reforms, particularly the requirement for open-access transmission, appear to have mitigated much of the potential for the exercise of vertical market power at the wholesale level, although transmission constraints still allow many dominant sellers to exercise market power. Thus, it appears that the more important role for bilateral contracts is in mitigating horizontal market power, as discussed below.

Horizontal market power

In electric energy and capacity markets, a party that controls a significant percentage of electric energy or capacity in a particular region has the potential to exercise horizontal market power in any of the markets for wholesale electricity products. Here we focus on the potential for horizontal market power in the two major wholesale markets, electric energy and capacity.

The potential exercise of horizontal market power in spot electric energy markets, considered difficult to identify[22] and to eliminate,[23] has received considerable attention from FERC, RTOs and state regulators. Market power is most easily exercised in spot markets. Buyers are captive in the market and cannot exercise market power. They will have to pay any arbitrarily high market clearing price (the price bid by the most expensive successful bidder) in order to meet their supply obligations. In the absence of adequate regulatory market abuse detection and mitigation, the risk for producers who withhold resources, or who bid them far above cost, is only that they will miss an opportunity to recover a contribution to capital cost or make a profit for that market period. This is an inherently asymmetric risk situation in which buyers are at a substantial disadvantage, especially in markets (like almost all electricity markets) that are not truly restrained by competitive forces among the sellers themselves.

Any option that enables buyers to reduce the quantity of electric energy they purchase from the spot market will tend to reduce the financial incentive for producers to exercise whatever horizontal market power they hold in that market. Such options include:

- reducing the quantity of electric energy required from those markets through energy efficiency;
- local and/or distributed generation or other forms of self-supply; and/or
- acquiring electric energy via bilateral contracts.

[22] Adamson, Seabron and Wellenius, Kevin, *Determination of Horizontal Market Power Abuse in Wholesale Electricity Markets, Frontier Economics, Cambridge, MA. December 1999.*

[23] Energy Information Administration, 2000, Chapter 7.

Reducing the quantity of electric energy purchased from the spot market mitigates the rewards for horizontal market power. An owner of generation has a financial incentive to exercise market power and manipulate prices directly related to the quantity of power sold into the market. By reducing the quantity of electric energy purchased from the spot market, and thus reducing the amount of power directly paid the spot market clearing price, both the profitability of and the incentive for the exercise of market power are reduced.[24]

In contrast, when transacting on a bilateral basis months or years in advance of delivery, both buyers and sellers have the option of deciding not to engage in any particular transaction and of waiting for a better opportunity to arise. In addition, a much wider range of resource options is available under these circumstances, including investments in energy efficiency and contracting with new resources if acceptable deals with existing generating resources are unavailable. This flexibility increases as planning horizons grow longer and the option of engaging more types of resources becomes feasible. Finally, some sellers should be willing to transact on a cost basis (assuming an acceptable level of return) on a long-term, bilateral basis, with pricing terms that may be indexed to fuel costs as noted above. For all of these reasons, it is much harder to manipulate prices in bilateral markets through the exercise of market power. Finally, the existence of a robust bilateral market in which a significant share of energy and capacity are transacted is an effective means of reducing market power in the spot market. Producers have less of an incentive or opportunity to profit from manipulating prices in a spot market that is truly just "residual" to bilateral markets—in fact, they are more likely to lose potential profit opportunities in the attempt.

However, bilateral and spot transactions in the same market are linked in ways that can allow market power to "spill over" into the bilateral arena. If buyers perceive a risk of market power and associated high prices in the spot market, they will be more eager to transact bilaterally and may be willing to pay a premium. Sellers may correspondingly demand a premium to transact bilaterally if they expect to do better than a true cost-based price in the spot market. Bilateral transactions do serve to limit exposure to price volatility and the risk of very high prices, and can lead to overall price benefits by reducing the opportunities to exercise market power. However, the expected price of power in spot and bilateral transactions under a given set of market conditions is the same. Thus a prerequisite for establishing healthy, cost-based bilateral markets is to ensure that spot markets are both competitive and limited in scope.

Market power in bilateral energy and capacity markets

Although market power issues in electricity markets are particularly acute in spot markets, it should not be assumed that there is no opportunity to exercise market power in bilateral markets. The potential exposure of bilateral contract prices to this potential market power has received relatively little attention compared to the spot markets.

As noted above, the best opportunities to exercise market power in the bilateral electric energy market occur in situations where purchasers are held captive and forced to transact for either political or institutional reasons; in these cases we maintained that the

[24] Adamson. op. cit.

transactions are not truly bilateral because they are not freely entered. The classic example of political circumstances conferring market power on suppliers occurred toward the end of the California energy market crisis in 2000, when Governor Gray Davis ordered the California Division of Water Resources (DWR) to cover all of the utilities energy requirements by purchasing electricity under long-term contracts. The very high spot market prices at the time, and the fact that the DWR had no choice but to transact quickly and in high volume, clearly influenced the contract prices which turned out to be quite high relative to electricity prices prevailing both before and after the crisis. California has since been attempting to undo the damage both by renegotiating and challenging the contracts entered into by the DWR.

Another prevalent structural point of entry for market power is the periodic auctions and RFPs held to acquire supply SOS customers. In many states these procurements are designed to secure from one-third to one-half of SOS supply for some future period in contracts with durations of 1, 2, and/or 3 years. The procurements are held only once or twice a year, several months in advance of when the electric energy is actually required.[25] Bidders place themselves at substantial risk if they participate in such an auction without first securing resources to back up their potential retail supply obligations. If there are only a few suppliers with sufficient uncommitted capacity to offer, these suppliers can control the availability and price of power for all bidders, or alternatively may be able to submit a high-priced bid and have that bid accepted. State rules vary with respect to the amount of oversight exercised to prevent this outcome, including the ability of some states to reject auction outcomes[26] if they do not appear to reflect competitive or reasonable prices.

The potential for market power in SOS auctions can be reduced by changing the process through which supply is acquired to meet SOS load. Those changes include reducing the portion of SOS supply sought in any single auction, holding auctions more frequently during the year, and seeking contracts of various durations longer than 3 years in addition to 1 to 3 years. Such changes would provide opportunities for more suppliers to participate in each auction, would reduce the risk and increase flexibility for auction participants, and would ultimately reduce the opportunity for a single supplier to dominate auctions for large proportions of retail load.

Market power in capacity markets

An entity that owns or controls a large share of generating capacity also has the potential to exercise market power, especially in organized capacity markets. The potential exercise of horizontal market power in capacity markets has received relatively little attention, due to the bilateral nature of capacity transactions in the past and the historically low costs (reflecting capacity surplus) in most electricity markets. More recently, however, capacity markets in PJM, New England, and New York have moved to an auction structure with more institutionalized incentives for withholding or strategic bidding of capacity in order to increase prices. As with energy markets, the potential for

[25] Some jurisdictions break the procurement up into three parts scheduled roughly a month apart in an attempt to reduce exposure to brief market excursions.

[26] For example, the Maine Public Utility Commission rejected all bids in an SOS procurement process in 1999. In this case, the role of SOS provider reverted back to the traditional utilities.

market power in the auction (in which LSEs are forced to transact) leaks into the bilateral market, creating an unequal risk profile for sellers and purchasers of capacity.

As with the spot electric energy market, any option that enables buyers to reduce the quantity of capacity they purchase from the mandatory capacity market will tend to reduce the financial incentive for suppliers to exercise horizontal market power. As with energy, those options include acquiring capacity via bilateral contracts, and reducing the quantity of capacity required from those markets through demand response, energy efficiency and distributed generation. By reducing the quantity of mandatory capacity purchases, each of these options reduces the probability of success from profiting from the exercise of market power in the annual capacity auction.

As with energy markets, one benefit that should not be expected as a rule from bilateral contracting in capacity markets is lower (or higher) prices than would be obtained in the corresponding spot market (with the possible exception of new resource developers who may offer a discount in exchange for a secure revenue stream.) Both sides of bilateral transactions have benefits associated with reduced risk, so it is not clear that either side will be able to extract a risk-reduction premium from the other on a consistent basis. Assuming a consistent and predictable price differential between bilateral and spot markets is a common and often costly mistake. More reasonable is the assumption that market participants will effectively arbitrage between these markets to eliminate any consistent bias.

5. Obstacles to long-term bilateral contracts in deregulated markets

This section addresses the obstacles to bilateral contracting and the parties who should be addressing those obstacles. FERC Docket AD07-7 is our source for the most recent comprehensive set of comments on policies and structural factors that would lead to a more conducive environment for long-term contracting. We reviewed those comments as well as state policies and rules that affect the climate for long-term bilateral contracting.

A. Market Participant Comments on Factors which Influence Long-Term Bilateral Contracts (Docket AD07-7)

The market participants who submitted comments in this Docket highlighted a number of factors as obstacles to healthy long-term bilateral contracting, including regulatory and market uncertainty, a lack of adequate long-term transmission planning, including long-term Financial Transmission Rights (FTRs), and opportunities for sellers to earn revenues high above costs in the single-clearing-price spot markets. These concerns, along with sample comments, are presented in this section.

Seller unwillingness to transact on a cost basis

From the perspective of many buyers, the primary obstacle for bilateral long-term contracting has been the unwillingness of sellers to contract even for base load supply on the basis of cost when they can earn above-cost rents in the spot markets. For example, Walter Brockway of Alcoa writes, [27]

> We found no supplier willing to discuss supplying us with anything other than electricity priced to reflect peak load generation, as well as placing on us all the risk of transmission congestion. Because we are a non-variable base load customer, we had expected that a competitive market would have at least brought us contract offers reflecting the cost of new base load supply, but we received no such offers. The contracts that were offered were short term (3 years or less) and completely based upon marginal pricing reflecting the most inefficient peaking units. Had we accepted any of them, the price for electricity at this facility would have doubled.
>
> …
>
> Generators ignore the forward market because they expect and get higher prices in the spot market, and there is nothing in the market structure that compels them or gives them incentive to recognize differences in load characteristics.

Many public power entities have historically depended at least in part on bilateral market purchases to meet their requirements. However, this has become increasingly difficult and expensive. For example, Duane Dahlquist, General Manager of Blue Ridge Power Agency, writes:[28]

> First, public power systems such as the members of Blue Ridge are seeing fewer and fewer bidders respond to solicitations for long-term requirements-type power supplies. We have seen large utilities that were strong, aggressive contenders in our 2002 solicitation, fall by the wayside in 2005 in response to our request.
>
> Second, we are seeing those that do bid, bid in at substantially higher prices. From what we know of their power supply portfolios, those bids are not based on the seller's own power production costs (including fuel price increases); rather they seem to reflect the clearing prices available in the PJM-run spot markets, which in turn are often set by natural gas fired generation. Bidders appear to be using variations of the same forward natural gas price curves and bidding virtually the same price. The Commission's Staff has, apparently, observed the same phenomenon. In its last State of the Markets Report, FERC Staff reported, "[i]n general, RTO Regulatory and Market Uncertainty and bilateral markets both produce prices that largely reflect the cost of fuel for marginal units."

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[27] Brockway comments, pp. 2-3.

[28] Dahlquist comments, pp. 7-8, reference omitted.

> Third, the clearing prices set in PJM's spot markets are affecting the prices and terms sellers in the bilateral market offer for longer term power supplies. The reason is, I believe, simple – why should a generator commit its resources to a long-term contract when it can receive high profits in the spot markets? It is simply more lucrative for many sellers to sell their power into the spot markets.

Cost-recovery risk of long-term commitments

A number of market participants (primarily representing sellers) stated that they were hesitant to make, if not prohibited from making, commitments for several years into the future when market conditions, rules and structures in those future years are so uncertain. Some respondents were unconvinced that the sanctity of contract terms would be honored and protected by FERC over the long term, especially given the ongoing attempts to have California's high-priced long-term contract terms altered. Others noted the risk of having cost recovery disallowed for regulated retail providers who enter into long-term contracts.

For example, Dan Allegretti, on behalf of Constellation Energy, writes:[29]

> Sending a clear message to the market as to how the Commission will view and respect the market-based rates embedded in bilateral agreements can help restore confidence in the integrity and enforceability of such agreements, thereby promoting their use.

On cost recovery, FirstEnergy[30] comments:

> A more fundamental problem than the availability of market intelligence is that buyers and sellers cannot get together on price. Why is this the case? We believe that the most compelling reason is uncertainty over state retail recovery of long-term contracts for states where retail choice exists but rate caps or political pressure make state commissions unwilling to provide the necessary assurance of rate recovery for long-term contracts. Recent Mobile-Sierra decisions opening up long-term contracts in California to prudence review create further uncertainty for sellers.

Commenting on the impact of regulatory risk on prices, the Ohio Public Utility Commission[31] notes:

> Not surprising, the long-term contracting issue comes down to pricing. Today, the price is being influenced by many factors including the risks associated with certain RTO charges; both the uncertainty of and volatility of current charges, as well as the uncertainty of those yet developed, create risk resulting in higher prices for long-term contracts.

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[29] Allegretti, p. 6.

[30] FirstEnergy comments, p. 9.

[31] Ohio PUC comments, p. 23; punctuation slightly altered to address apparent typographical errors.

A number of respondents felt that the primary obstacle was simply that buyers and sellers in general had differing expectations regarding future prices, and different levels of willingness to accept cost risk. Those differences make it difficult for them to agree on pricing under long-term contracts. For example, Andy Ott of PJM writes:[32]

> …certain buyers may have the expectation that forward contract prices should be indexed based on depreciated embedded-cost-based rates verses long run marginal costs and the sellers have the opposite expectation. This issue is not limited to regions with organized markets, it is a universal phenomenon related to the increased uncertainty across the industry, volatility in fuel prices and concerns related to the need for substantial investment in transmission and resource infrastructure to support increasing demand for electricity into the future.

Dan Allegretti[33] takes a similar view:

> The perception of inadequate long-term contracting opportunities may indeed be a matter of different expectations…the critical perception for both the seller and the buyer must be the opportunity cost of transacting instead in the shorter-term market. As long as the risk trade-offs associated with contracting forward are perceived as costlier than the alternative of the expected outcome in the spot market, the parties will choose not to contract forward. The point is not that the opportunities to contract forward are inadequate but rather that the opportunities to transact shorter-term are more attractive. This is simply buyers and sellers making rational decisions in the marketplace.

Thus a primary issue identified is the perception of risks faced by buyers and sellers, which cause them to diverge on the prices at which they feel they can reasonably enter into long-term commitments. This makes it difficult to come to terms acceptable to both sides if the risks faced are asymmetrical. As expressed by the Midwest ISO:[34]

> The essential attribute of a long-term contract is that it allows parties to bilaterally hedge future market risks. Buyers that are insulated by the regulator from the risk of scarcity pricing have a diminished interest in entering into long-term contracts. Similarly, sellers that secure a regulatory guarantee to full cost-of-service compensation for capacity have a muted incentive to enter into long-term bilateral contracts. The Commission's proposed pricing regime set forth in its demand response proposals will encourage LSEs to secure long-term sources of supply in order to avoid high prices in the real-time market. Risks, however, must be symmetrical to ensure that there is a mutual incentive to execute a fair and balanced long-term contract.

[32] Ott comments, p. 7.

[33] Allegretti comments, pp. 5-6.

[34] MISO comments, p. 15

In many of today's electricity and capacity markets, the risks faced by buyers and sellers are not symmetrical. Both sides know that it is the buyers who ultimately must procure both capacity and energy in order to meet their obligations to serve load, or face severe sanctions. Further, buyers face asymmetric risks with regulators and their customers, making it inherently more risky for them to make long-term commitments. If they enter into contracts that later turn out to be "out of the market" they risk being left without cost recovery for the excess. These entities can only mitigate this asymmetry by transacting in a truly competitive long-term market, in which they can demonstrate a clear relationship between the prices they pay and the cost of the product they procure.

On the other hand, sellers (particularly marketers) are more likely to be held accountable for purchasing power bilaterally and missing opportunities to earn high rents in the spot market, whereas they are unlikely to be held responsible for low prices in the spot markets. This was articulated by Don Sipe on behalf of the American Forest Products Association:[35]

> …far more importantly for our purposes here, is the knowledge that by staying with the real time LMP or entering into contracts whose price terms simply pass through LMP results, one cannot be faulted in any particular interval for "losing money." Few marketing employees would expect to be fired for "not making" a million dollars, but could very easily lose their positions if it could be shown they had "lost" a million dollars. The market dynamics created by LMP create a perception that in any hour where a contract price is not as high as a particular hour of LMP, a loss has been suffered. This perception does not need to be rational to be a significant motivator of behavior. The over-weighting of losses as compared to gains means that in any evaluation of a long term contract, even if the expectation were that losses would be balanced by corresponding periods where the contract price exceeded the clearing price, those losses (as opposed to the gains) would be overweighed and require a risk premium out of proportion with the value being offered.

Thus while some parties see no obstacles other than a divergence of price expectations between buyers and sellers, other parties note that this divergence has its roots in structural market flaws which lead to risk asymmetries. Those structural problems in turn lead to an undue reliance on short-term contracts and spot market purchases, and ultimately to higher prices than might otherwise pertain in both the spot and bilateral markets. This is a market failure based in the asymmetry of risk between buyers and sellers that tends to push transactions into the spot market and to increase prices in general. As a result, the parties will not increase their reliance on longer-term contracts until they are required to do so through changes to existing policies, such as are discussed below.

[35] AFPA comments, p. 31; references removed.

The undue reliance on short-term contracts and spot market purchases under current policies is not what was originally envisioned by the proponents of competitive electricity markets. As summed up by a coalition of industrial consumers,[36]

> In a real competitive market, power prices would be set by negotiated transactions between willing buyers and sellers, not dictated by RTOs or regulators or "organized markets." In a real competitive market, suppliers would be seeking out customers, offering longer-term bilateral contracts, and striving to add value through innovation. In a real competitive market, barriers to entry would be minimal or non-existent. In a real competitive market, demand elasticity would not be an ever-present challenge. The things Industrial Customers see every day in the current electric industry are not consistent with the results they would expect to see in a competitive market.

Transmission planning and long-term FTRs

Two structural improvements frequently mentioned in the comments to FERC under AD07-7 that could help to encourage increased long-term, bilateral contracting are improved transmission planning, and availability of long-term Financial Transmission Rights (FTRs). This suggests that a significant obstacle to long-term delivery commitments is uncertainty regarding future transmission costs, which today can change as frequently as every five minutes under LMP. Improvements to long-term transmission planning on a regional basis would help assure market participants that transmission investments will keep up with need, regardless of the immediate self-interest of the local utilities (or their generation affiliates) that would be responsible for building the infrastructure. Long-term FTRs would have a similar effect on a purely financial basis by giving market participants certainty in transmission costs over a number of years, rather than the term of one-year or less that is currently available in most RTOs.

On the need for long-term FTRs, Exelon writes:[37]

> Transmission congestion costs in organized markets can cause the price of transmission to vary, thereby creating uncertainty for transmission customers about the price of delivered electricity. This uncertainty impedes long-term contracts between wholesale buyers and sellers of electricity in competitive wholesale markets. Long-term financial transmission rights enable transmission customers – whether load serving entities (LSEs) or generators – to enter into long-term contracts at a fixed price and hedge the risk of congestion.
>
> …
>
> LSEs such as distribution utilities often enter into long-term contracts at set prices with suppliers of electricity to serve their load. But when the cost of the transmission service varies because of congestion costs, these LSEs cannot be

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[36] Joint comments of Industrial Consumers, Page 5.

[37] Exelon comments, p. 14

> certain what the cost of delivered power will be, even though they have a fixed price contract for delivered electric supplies. By the same token, new generators wishing to sell to customers cannot be certain what the price of transmission will be and therefore what their revenues will be. Without certainty of revenues, investors in new generation, such as wind, have a hard time finding financing.

Similarly, Jan Schori writes on behalf of the Larger Public Power Council:[38]

> Certainty is what drives much utility decision making, especially for load serving entities with the obligation to serve. This is the principal reason why my utility and many LPPC members gravitate to bilateral markets. Uncertainty regarding the expense of transmitting power across RTO/ISO systems (in part, resulting from volatile congestion and marginal loss charges) is the principal challenge confronting most if not all organized markets and this uncertainty remains the significant concern to LPPC members doing business within and through organized ISO and RTO markets. This is a particular concern of mine as I think about how to deliver to my load renewable resources that are remote from our system, as most are. This discussion relates to [FERC's] question on what can be done to improve the integration of remote resources that we would like to procure on the competitive market.

The Washington, DC Office of People's Council expressed concern about relying on local distribution companies to provide the transmission infrastructure to support a healthy bilateral market:[39]

> …transmission provides the necessary infrastructure to facilitate competitive wholesale markets. There must be adequate transmission in order for the sellers to meet the buyers. An open, inclusive and collaborative process is needed that includes regional and local facilities in order to achieve long term regional rate design. This simple fact, however, points clearly to the irony of our current situation; transmission owners with competitive generation affiliates will resist transmission expansion if it could make their affiliate less profitable.

B. State Policies on Long Term Contracts

Most states with deregulated retail markets are reviewing their policies regarding the role of long-term bilateral contracts in standard offer supply service. From the inception of their retail markets to the present, policies in those states have generally discouraged (if not prohibited) truly long-term bilateral contracts. State policies have generally supported contract durations of less than five years—long enough to smooth out some price volatility, but not long enough to adequately support development of new resources.

In the last few years, as legacy buy-back contracts have expired and wholesale prices have risen, many states have begun to reconsider those policies. However, in order to be successful, state policies would have to provide assurance that contracts which are

[38] Schori comments, p. 2

[39] Comments of the DC OPC, p. 7

prudently entered into under then-current market conditions will not be second-guessed when conditions change. As indicated by the comments in FERC Docket AD07-7, many LSEs and other parties continue to have concerns about the risk of being penalized for entering long-term commitments at prices which turn out to be higher than spot prices, resulting in stranded costs. State policies that specifically encourage or promote a portfolio of contract durations could go a long way to alleviate these concerns.

Summaries of current state policies, along with sources for more information, are presented in Appendix C.

6. Conclusion: Mixed Reviews

Overall, we find that today's RTOs have failed to create a vibrant and competitive environment for bilateral contracting, and that as a result, bilateral contracts are not playing the role they should in maintaining prices for consumers at a level comparable to the cost of providing service. We find that in many cases, the gap between what buyers are willing to pay and what sellers are willing to accept under long-term contracts has been too great to bridge. This has been partially the result of structural failings in the market that increase the risk for long-term contracts, such as the lack of long-term FTRs to hedge transmission risk and inadequate transmission planning in at least some cases. However, the primary obstacle has been a fundamental asymmetry of risk, whereby it is only buyers who are exposed to substantial risk in the spot markets. Sellers have nothing to lose by waiting to transact in spot markets in which they will face bid-based clearing prices, the potential for windfall profits, and very low risk because they cannot be forced to sell below their offer prices. The movement of capacity markets into an auction structure has only exacerbated this situation by creating yet another market in which LSEs are forced to transact.

The one limited situation in which bilateral markets have performed their function is in providing a source of secure revenue for certain types of new resources. This is particularly the case with new renewable resources whose developers are smaller entities without ready access to the large volume of capital that would otherwise be required. In this case, developers have generally found willing buyers and little trouble negotiating mutually agreeable terms.

Thus we conclude that the asymmetries of risk in the spot markets is probably the single most important element impeding the development of bilateral contracts. Unless and until RTOs are able to truly eliminate this problem and design spot markets that more fully reflect production cost and address market power issues, these asymmetries will persist and robust, competitive, long-term bilateral markets are unlikely to develop in RTO regions.

At the same time, the existence of a robust bilateral market may be a crucial prerequisite to mitigating market power in energy and capacity markets. For this to occur there has to be a sufficient incentive for both parties to transact in the bilateral market, leading to symmetrical risks and comparable judgments of an acceptable price at which to transact. As long as resource owners can be confident of high profits in the spot markets for capacity and energy, these conditions will not be met. Indeed, the new capacity markets take a step in the opposite direction by essentially guaranteeing cost recovery to all resources, and substantial profits above normal levels of cost recovery to many. Under these circumstances, only the buyers bear risk by waiting to transact in the spot market. These are not conditions under which a healthy long-term bilateral market can develop and thrive.

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Appendix A: Data on Contracts for New Capacity in PJM

PJM **All listed plants are in PJM territory. Does not include IL and ID plants outside of PJM.**

Plant Code	Name	Town	State	2004	2005	2006	Bilateral Contract	Simple Bilat	Capacity	Buyer	Comments
56050	Inner Harbor East Heating	Baltimore	MD	2.1			Y (?)	Y	2.1	Inner Harbor East	Trigen CHP (heating, cooling, and power) in multiple-use development in Baltimore inner harbor (peak shaving w/ utility - does this imply no contract?)
52149	West Point	West Point	PA	2.6			?	?	2.6		
10123	Hoffmann LaRoche	Nutley	NJ	10.6			Y	Y	10.6	Hoffmann LaRoche Pharm	Assumed industrial; in Nutley at Hoffmann LaRoche plant site
10224	Merck Rahway Power Plant	Rahway	NJ	10.8			Y	Y	10.8	Merck and Co Pharm	Assumed industrial; in Rahway NJ at Merck plant site
4257	Easton 2	Easton	MD	5.4 x 2			Y	Y	10.8	Muni - Easton Utilities	Oil plant
7336	Anderson	Anderson	IN	85.9			Y	Y	85.9	Indiana Municipal Power Agency	Peaker built by Indiana Municipal Power Agency
3130	Seward	New Florence	PA	585			N	N	585		"It is the largest waste coal-fired generating plant in the world and the only merchant plant of its kind in the U.S. "

55667	Lower Mount Bethel Energy	Bangor	PA	658			N	N	658		Owned by PPL; "The majority of the electricity produced by the new plant will be used in Pennsylvania and New Jersey."; "Lower Mount Bethel Energy, LLC submits a Triennial Market-Based Rate..."
55801	FPL Energy Marcus Hook LP	Marcus Hook	PA	836.1			N (...)	N	836.1		Sunoco refinary uses steam from plant, remainder sold. "This highly efficient power plant will provide clean, cost-effective electricity to the region,"
55298	Fairless Energy Center	Fairless Hills	PA	1338			N	N	1338		Dominion plant. "we're increasing our footprint in a market that accounts for 40 percent of the nation's demand for energy"
56289	Salem Street Dept	Salem	VA		1.8		?	?	1.8		
56363	New Design	Danville	VA		1.8		?	?	1.8		Distillate Fuel Oil
56364	Kentuck	Danville	VA		1.8		?	?	1.8		Distillate Fuel Oil
56365	Westover	Danville	VA		1.8		?	?	1.8		Distillate Fuel Oil
56464	Jay County	Portland	IN		3.2		Y	Y	3.2	Jay County REMC	Landfill gas plant (2 units) operated and sold by Rural Electric Membership Corp (REMC)
55884	Rolling Hills	Boyertown	PA		5.5		N (?)	N	5.5		Appears to be market based... evidence is skim
56462	Geneva Generation Facility	Geneva	IL		29.5		Y	Y	29.5	City of Geneva	Chicago Daily Herald, Feb 15th 2007. "Geneva lawsuit blames Nicor for problems at power plants"
10118	Harrisburg Facility	Harrisburg	PA			24.1	Y	Y	24.1	Penn Power and Light	Harrisburg Resource Recovery Facility by Covanta; "The energy is sold to Pennsylvania Power and Light."

56299	Wind Park Bear Creek	Bear Creek	PA			21.5	Y	Y	21.5	Pepco	Pepco bundling energy in 33-month green energy contract for NJ state agencies
2406	PSEG Linden Generating Station	Linden	NJ			1186	N (?)	N	1186		Exelon merger with PSEG forces sale of 6 plants, including Linden; no clear long term contract being transferred with sale.
56300	Jersey-Atlantic Wind Farm	Atlantic City	NJ			7.5	Y (20 yr)	Y	7.5	Atlantic County Utilities	Will pay 7.9 cents per kilowatt hour for 20 years (rather than 12 cents currently). Wind project is on sewage treatment facility grounds.
56429	AMERESCO Delaware South	Georgetown	DE			4	Y (sort of)	Y	4		Landfill gas on Delaware Solid Waste grounds is sold to Ameresco, who shares profits with DSW. Ameresco sells to Constellation, who sells wholesale
56430	AMERESCO Delaware Central	Sandtown	DE			3	Y (sort of)	Y	3		Landfill gas on Delaware Solid Waste grounds is sold to Ameresco, who shares profits with DSW. Ameresco sells to Constellation, who sells wholesale
56571	Eastern Landfill Gas LLC	White Marsh	MD			3	N	N	3		Pepco operated. "Eastern Landfill Gas, LLC (Eastern) filed an application for market-based rate authority,..."
56005	Pleasant Valley	Harrisonburg	VA			2	?	?	2		No info - diesel generator on Dominion property
56420	Renick Run 03-04	Columbus	OH			1.4 x 2	?	?	2.8		No info - diesel generators

Appendix B: Data on Contracts for New Capacity in New England

New England ISO

Plant Code	Name	Town	State	2004	2005	2006	Bilateral Contract	Simple Bilat	Capacity	Buyer	Comments
56189	Waterside Power, LLC	Stamford	CT	23.2 x 3		23.2	?	?	92.8	-	Waterside-built temporary diesel peakers. Both 2003 units operated from 6/03 to 10/03, one 2004 unit decomissioned 2/06, recomissioned 5/06.
55034	J & L Electric	Strong	ME	0.7			?	?	0.7	-	
50082	International Paper Livermore Hydro	Livermore Falls	ME	1			Y	Y	1	International Paper Co	On campus of International Paper Co
56426	AMERESCO Chicopee Energy	Chicopee	MA	1.9 x 3			Y	Y	5.7	Muni - Chicopee	Landfill gas plant - power is sold to Chicopee Electric Light
55999	Trigen Revere	Revere	MA	2.9 x 2			20 yr	Y	5.8	Necco	6 MW CHP plant at New England Confectionery Company (Necco) Revere
56024	Berlin Gorham	Berlin	NH	25			10 yr	Y	25	Nexfor	Cogen for pulp / paper facility in Berlin/Gorham

55126	Milford Power Project	Milford	CT	289 x 2			?	?	578	-	Originally supposed to begin operation 12/01, but accident killed 2 in 2000. Replaces Devon peakers.
56256	John Street 1 & 2	Wallingford	CT		1.8	1.8 x 2	Y	Y	5.4	Muni - CMEEC	CT Municipal Electric Energy Cooperative (CMEEC) bult in SW CT in response to ISO-NE request for 300 MW load resource
56257	Cytec 1 & 2	Wallingford	CT		1.8 x 2	1.8	Y	Y	5.4	Muni - CMEEC	CT Municipal Electric Energy Cooperative (CMEEC) bult in SW CT in response to ISO-NE request for 300 MW load resource

Appendix C: Examples of State Policies on Long-Term Contracting in Electricity Markets

Following are brief examples of state policies on long-term contracting in electricity markets. Sources for more information follow each description.

Maine: In July of 2007 Chapter 316 of the Public Utilities Commission was created to implement the State's policy of using long-term contracts for capacity resources. The goal is to minimize electricity costs. Contracts are authorized for capacity and associated energy, as well as interruptible load, demand response, or energy efficiency capacity resources. Contracts will be no more than ten years in duration unless a longer term would be in ratepayers' interest. The policy was designed to:

- Increase Renewable capacity by 10% from Dec 31, 2007 levels by 2017;
- Reduce prices and volatility in the electricity market;
- Reduce greenhouse gas emissions from electricity generation; and
- Develop new capacity or decrease demand to mitigate cost impacts of Federal or regional capacity mandates.

Source: http://www.maine.gov/tools/whatsnew/attach.php?id=28423&an=1

Massachusetts: In November of 2007 House Bill No. 4365 directed distribution companies to "enter into cost effective long-term contracts to facilitate the financing of renewable energy generation within [the state]." Contracts are authorized for Renewable Energy Credits (RECs). The long term contract policy, promoting contracts with terms of 10-15 years, is separate and distinct from State's Renewable Portfolio Standard.

In addition, the Green Communities Program was created to give grants and loans to municipalities for energy efficiency projects. To qualify, a city must gain a certificate based on efforts to reduce energy consumption or promote clean generating facilities. Entering into long term contracts for renewable generation is a recognized effort toward gaining a certificate.

Source: http://www.mass.gov/legis/bills/house/185/ht04pdf/ht04365.pdf

Connecticut: Section 71 of Connecticut's July 1, 2007 energy bill addressed long-term contracts for Renewable Energy. This bill "allows electric companies, starting January 1, 2008, to meet the Renewable Portfolio Standard by procuring renewable energy certificates under long-term contracts." Section 124 "requires electric companies to enter into long-term contracts with generators of Class I renewable resources." The number of renewable energy credits required to be under long-term contract will increase to 150 MW starting October 1, 2008. Resources must have received funding from the clean energy fund and individual projects must be at least one megawatt in size to qualify. Contracts should last up to 15 years.

Source: http://cga.ct.gov/2007/BA/2007HB-07432-R01-BA.htm

Delaware: In May, 2007, the Electric Utilities Retail Supply Act of 2006 was amended to designate all distribution companies subject to the jurisdiction of the Commission as the standard offer service supplier and returning customer service supplier in their respective territories. Distribution companies can "enter into long and short-term supply contracts, own and operate generation facilities, build generation and transmission facilities, make investments in demand-side resources and take any other Commission approved action to diversify their retail load supply." The goal of the policy is to spread out the impact of recent and anticipated rate increases and enable state agencies to explore alternative options of Standard Offer Service procurement at reasonable and stable prices; provide cost-effective, long-term system benefits; and bring to the market energy efficiency, renewable distributed generation, and bilateral contracts. Delmarva Power is required to conduct Integrated Resource Planning for a forward-looking 10 year time frame and is required to file a proposal to obtain long-term supply contracts.

Source: http://depsc.delaware.gov/irp.shtml

Illinois: In November, 2007, the Illinois legislature amended Section 16-111.5(b) of the Public Utilities Act ("PUA"), to create the Illinois Power Agency to procure power from indigenous coal or renewable resources, and to supply this power to municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois. The Act includes a proposed mix of contracts to meet load not covered by preexisting contracts: "monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity" obligations. While this Act does not specifically require *long-term* contracts, it does specify that "Nothing in this Section precludes consideration of contracts longer than 5 years."

Source: http://www.ilga.gov/legislation/publicacts/95/095-0481.htm

Michigan: The Michigan Energy Plan Central Station Policy notes that an "independent power producer is unlikely to build base or intermediate load plants without a long term power purchase contract with load serving entities in Michigan. Contracts could potentially be secured with a combination of Michigan's municipal and/or cooperative utilities, which have not yet experienced customers migrating to AES competitors." Also recognized was reluctance by major utilities to sign contracts with independent power producers "due to uncertainty of customer need, regulatory risk, and wholesale market price risk."

The "Staff notes that utilities are free to make use of competitive bidding for power purchase agreements. These contracts have already been used to secure long term and short term capacity needs. Staff does not recommend that competitive bidding for power purchase agreements be mandatory."

The Staff cites the following concerns with securing long term power agreements:

"Risks of future uncertainty, such as fuel price and air emissions

"Staff is wary of undertaking a contentious, complex appraisal of multiple bids that may result in litigation."

"Staff recommends that a competitive bidding option must be offered, but also recommends it should be limited to the engineering, procurement and construction work for a new plant."

Source:
http://www.cis.state.mi.us/mpsc/electric/capacity/energyplan/cnfupdate/energyplan_appendix1_centralstation.pdf

Pennsylvania: In May of 2007 the Rulemaking Concerning Default Service and Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant, Docket No. L-00040169, stated:

> …there should be regular adjustments to default service rates to reflect changes in the actual, incurred costs of the Default Service Provider ("DSP"). This practice of regular adjustment with the use of spot market energy supply products will ensure that rates more closely track prevailing wholesale energy prices, and that customers do not experience large changes in rates as program terms expire.
>
> …
>
> DSPs should consider a portfolio of energy supply products when developing their procurement plans. A reasonable procurement strategy may include a mix of fixed-term and spot market energy purchases, the use of laddered contracts, etc. The Commission discourages the practice of procuring all needed supply for a period of service at a single point in time. Instead, we recommend that the DSP use multiple competitive procurements and spot market purchases to meet its obligations and to reduce the risk of acquiring all supply at a time of unusual price volatility. We expect that DSPs will gradually increase their reliance on shorter term contracts and spot market energy products over time.
>
> …
>
> We do not attempt to dictate the exact manner by which every DSP will acquire electricity, adjust rates, and recover their costs. The Commission is issuing a separate policy statement that contains guidelines for DSPs in the areas of procurement, rate design, and cost-recovery.

Source: http://www.puc.state.pa.us/PcDocs/666193.doc