Competition in the U.S. Electric Power Sector:
Some Recent Developments

by

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INTRODUCTION

This paper examines recent efforts to expand competitive opportunities in the electric power sector in the U.S. I start with a brief overview of the structure and regulation of the U.S. electricity sector as it existed in the mid-1980s. I then turn to a discussion of the role of what I will call "wholesale market competition" and how it has expanded during the last decade. Finally, I will discuss more recent efforts to expand competitive opportunities for retail customers. I conclude with some thoughts about future developments.

THE U.S. ELECTRICITY SECTOR[2]

a. Industry Structure

There are over 3,000 public utilities engaged in the generation, transmission and/or distribution of electricity in the United States.[3] These entities vary widely in size, structure and ownership form. Roughly 75% of U.S. generating capacity and retail sales of electricity are accounted for by over 100 investor-owned utilities (IOUs). These IOUs traditionally have been vertically integrated in the generation, transmission and distribution of electricity, providing "bundled" service to retail customers which they serve exclusively in specific geographic areas. IOUs vary widely in size from very small systems with a few hundred megawatts of load, serving

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[2]I offer only a very brief overview of the structure and regulatory framework governing the U.S. electricity sector. For a more detailed discussion see Joskow and Schmalensee (1983) and Joskow (1989).

[3]In addition, there are over 4,000 "non-utility" generating facilities which provide electricity to a host industrial customer or sell it to a local utility for resale.

a single small metropolitan area, to very large systems with over 20,000 Mw of capacity serving customers is several adjacent states (e.g. American Electric Power Company, an interstate holding company with operating subsidiaries serving portions of seven states.)

There are roughly 2,000 "publicly-owned" municipal and state[4] utilities. These entities account for about 8% of utility supplied generation. Many of these entities were, for most of their histories, small unintegrated distribution companies serving a single municipality. Historically, they relied primarily on an IOU that surrounded them to provide the generation service that they required to serve their customers. As I will discuss in more detail presently, by the 1970s these municipal systems were increasingly able to provide for their generation needs through joint-ownership of new generating facilities and through purchased power contracts with competing supply sources other than their host utility in an evolving wholesale market. To enable them to do so, the local utility had to supply transmission or "wheeling" service to provide a contract path between the competing generation source and the municipal distribution company's load. These arrangements were facilitated by the creation of a variety of state agencies (e.g. the Massachusetts Municipal Wholesale Electric Company) which aggregated the needs of multiple municipal distributors, financed and constructed new generating facilities to serve their needs. There also exist several large municipal electric power system which are fully vertically integrated and, aside from ownership form, are indistinguishable from IOUs (e.g. Los Angles Department of Water and Power and the Sacramento Municipal Utility District).

Beginning during the Great Depression of the 1930s, the federal government began to implement policies to bring low-cost electricity to rural areas and to develop the hydro-electric potential on the nation's rivers. The Rural Electric Cooperative program provided (and continues to provide) low-interest loans and other assistance to cooperative distribution and generating entities. There are roughly 1,000 rural electric cooperative operating in the U.S. today.[5] They accounted

[4]When I use the term "state" in what follows I will be referring to one or more of the 50 states that make up the U.S. When I use the term "federal" I will be referring to the national government in Washington, D.C.

[5]They are no longer all rural and the people served by them are not necessarily poor.

for 5% of the electricity supplied by utilities in 1992. Together, municipal and cooperative distribution system account for nearly 25% of U.S. electricity sales. The differences between what they sell and what they generate is made up for primarily with purchases from IOUs and federal Power Marketing Agencies. The federal government's efforts to develop hydroelectric capacity on the nation's rivers led to the construction of dams and the creation of several Federal Power Marketing Agencies (e.g. Tennessee Valley Authority and Bonneville Power Authority) to operate these facilities and to sell the power they produce to utilities for resale to ultimate retail customers.[6] Federal entities account for about 8% of the generation in the U.S. Under federal law, cooperative, municipal and state-owned utilities have preference to this power which is often priced well below market value.

In 1992, IOU, municipal, and cooperative utilities and federal power marketing agencies operated generating facilities with aggregate capacity of 740,000 Mw.[7] These facilities rely on a variety of different fuels to produce electricity (56% coal, 22% nuclear, 10% natural gas, 3% oil, and 9% hydroelectric, although fuel use varies widely from region to region.) From a physical operating perspective, the organization of these entities into physically integrated electric power networks is fairly complex. Vertically integrated utilities typically operate their own "control areas." The control area operator is responsible for dispatching generating plants, balancing load and resources, maintaining frequency and voltage on its transmission network, coordinating operations with interconnected control areas and scheduling exchanges of electricity between them. In some areas of the country, utilities have joined together to create "tight power pools" which act as control areas for multiple utilities and centrally dispatch all of the generating facilities in the pool based on

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[6]Some of these federal entities went on to build fossil and nuclear capacity as well once they had exhausted the hydroelectric potential in their respective areas.

[7]There was another 55,000 Mw of "non-utility" generating capacity in operation in 1992 as well. These facilities are primarily "qualifying facilities" (QF) under the Public Utilities Policy Act of 1978 (PURPA), which I will discuss presently.

economic criteria and without regard to ownership.[8] For example, the New England Power Pool created a single control area for the utilities in the six New England States and is responsible for dispatching virtually all of the generating facilities in that region based on a minimum operating cost criterion. The New York Power Pool provides central dispatch for all of the utilities in New York, and the PJM pool centrally dispatches generation for the utilities in New Jersey, Pennsylvania and Maryland.

All together, however, there are over 140 separate control areas in the U.S. These control areas are linked together into three synchronized AC systems: The Eastern System, covering the utilities (roughly) east of the Rocky Mountains (and portions of eastern Canada), the Western System, covering the western states (and portions of western Canada and Mexico), and a separate system that covers most of Texas. The control areas within each of the two major interconnected sytems rely on a wide variety of bilateral and multilateral interconnection and coordination agreements to maintain reliability, provide for economical exchanges of electricity, and to guard against free riding problems (e.g. loop flow, differences between scheduled flows and actual flows, etc.). A set of 9 regional reliability regions have been created to develop operating rules and to facilitate coordination among these many interdependent entities.

b. Economic Regulation: States

In what follows, I will focus on the IOU sector, because it is by far the largest sector and the one that has been affected most significantly by the expansion of competitive opportunities. The origin of most investor-owned utilities can be traced to municipal franchises for the distribution of electricity that began to be issued in the 1890s. Regulation of rates and service standards was originally the responsibility of the local municipality issuing the franchise. As the electricity sector grew and transmission and generation technology developed, extensive merger activity between small independent distribution companies took place. Utilities grew to span geographic areas that

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[8]Dispatch is based on the marginal operating costs of the various units that are part of the pool subject to must run, transmission, voltage, and other constraints. The owners of the generating facilities share the savings achieved by central dispatch compared to a simulated "self dispatch."

encompassed many cities and towns. By 1905, individual states began to create state public utility commissions which took over regulatory responsibilities from the municipalities.[9] By 1920, two-thirds of the states had moved to a state commission-based regulatory system and today all of the states with IOUs have state commissions with broad responsibility to regulate retail prices, and to promote the economical and reliable supply of electricity by IOUs.

Although there are some variations, the basic nature of economic regulation of electric utilities is quite similar from state to state. IOUs generally have a de facto exclusive franchise to make electricity sales at retail in a well defined geographic area. They have a legal obligation to serve all of the retail customers located in their service areas economically and reliably based on tariffed rates that are not "unduly" discriminatory. Most IOUs have fulfilled their service obligations under their retail distribution franchises and state laws by taking an ownership interest in the generating and transmission capacity required to serve the needs of their retail customers (i.e. they vertically integrated). In return for their exclusive distribution franchises, IOUs are subject to extensive economic regulation by state commissions. The state commissions regulate the prices that the utilities can charge customers, the non-price terms and conditions of service, and are often actively involved in decisions about investments in new generating and transmission facilities.[10]

State commissions typically rely on what is called "cost of service" or "rate of return" regulation to determine the prices that utilities can charge. Prices (and associated adjustment formulas) are determined in evidentiary hearings. These hearings are divided into two phases. The first phase determines the utility's overall "revenue requirements" or "rate level". The second phase determines the utility's "rate structure." That is, how the total "revenue requirements" will be recovered through specific tariffs made available to different types of customers (residential, farm, small commercial, large industrial, etc.). To determine the utility's revenue requirements, the commission must determine the "allowable" operating costs of the utility (e.g. fuel, maintenance, and

[9]Municipally-owned utilities are generally subject to economic regulation by their respective municipal governments rather than by state public utility commissions.

[10]Some states require formal approvals before utilities can invest in major new facilities, while others review these decisions ex post.

other operating costs) and the "capital related" charges that the utility is allowed to include in its rates to cover the depreciation, interest costs, and the cost of capital associated with equity investments in generation, transmission and distribution facilities. These capital related charges are determined by first computing the utilities "allowable" capital stock or "rate base," and then determining the appropriate depreciation charges and the "fair rate of return" that the utility should be allowed to earn on this rate base. Virtually all commission have come to adopt a "depreciated original cost" accounting system to determine the rate base and annual depreciation charges. This accounting system in turn requires that the fair rate of return reflect the nominal cost of capital incurred by the utility if the investors are to recover fully their investments in utility assets.[11]

Not surprisingly, most of the controversy over rates in rate hearings turns on which operating costs should be "allowed" and which "disallowed" because they are unnecessary, which capital investments should be included in rate base, and what the appropriate "fair return" on investment should be. Thus, these hearings provide a framework for the regulatory process to penalize a utility for incurring unnecessary operating costs or for making "inefficient" investments. The rules governing these decisions are fairly vague and subject to a great deal of controversy and sometimes influenced by political pressures.

Of most relevance to the discussion that follows, however, is the treatment of investments in long-lived facilities (or long term contractual commitments to purchase power). Should the "efficiency" of these investments be measured *ex ante*, based on the information available when the investment decisions were made or *ex post*, based on actual realizations of demand, fuel prices, technological change, etc.? Most commissions have taken an *ex ante* approach, recognizing that this is the approach that is most consistent with prevailing cost of service ratemaking techniques used to determine prices. As a result, whether the costs associated with a facility are included in rates or not generally depends on whether the associated investment was "prudent" or "imprudent" given the

[11]See Schmalensee and the references he cites for the properties of a depreciated original cost accounting and ratemaking system.

information available to managers when the investment decisions were made.[12]

This ratemaking system has the property that the expected present discounted value of the cash flows associated with capital related charges equals the cost of the original investment at the time the investment is made, and therefore satisfies an important investment viability constraint (investment will only be forthcoming if the expected discounted value of future cash flows is greater than or equal to the cost of the investment) and fairness or rent extraction constraint (customers are charged no more than the "cost of service" over the life-cycle of capital investments).[13] However, it also has the property that the prices charged at any point in time may be too high or too low compared to the true economic cost of service at that point in time. For example, if there is a demand slump and their is excess capacity, regulated prices will rise to cover the fixed costs that must be spread over a smaller sales base rather than fall to reflect the fact that the marginal cost of additional sales in the short run is quite low.[14]

This "cost plus" ratemaking system has been criticized for providing poor incentives for cost minimization. While this regulatory system, as with all regulatory systems (and most markets), is far from perfect, it is not a pure cost plus system. As I have discussed elsewhere, there are two primary attributes that provide incentives to control costs.[15] First, prices are not constantly readjusted to reflect changes in costs and the associated "regulatory lag" provides incentives to reduce costs.[16] Second, regulators have the authority to "disallow" costs for ratemaking pursposes

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[12]Regulatory rules must adhere to a U.S. constitutional requirement that they provide the utility with a "reasonable" opportunity to recover its costs, including a fair return on its investment. Depreciated original cost ratemaking is only compatible with an ex ante evaluation system. This is (to put it simply) because this ratemaking technique does not allow a utility to earn more than book accounting costs when the value of electricity exceeds these accounting costs. Disallowing capital items when the market value is less than the accounting cost would make investments to appear unprofitable ex ante.

[13]In theory, depreciated original cost ratemaking has the property that the expected present discounted value of future cash flows is equal to the depreciated original cost of the facility at every point in time as well See generally Schmalensee and the references he cites.

[14]Appropriate rate design changes can mitigate this kind of distortion, however.

[15]See Joskow and Schmalansee (1986) and Joskow (1989).

[16]Indeed, the much touted "price cap" regulation in practice is institutionalized regulatory lag.

if they conclude that they are unnecessary or inefficient.

Once the "revenue requirements" are determined in a hearing, the Commission must then determine the "rate structure" that will define the specific prices that will be charged to individual types of customers to yield (roughly) the aggregate revenue requirement that has been determined to be reasonable. Utilities typically have a large number of tariffs available to customers that fall into different size and voltage classes. Average prices for small residential and commercial customers are generally relatively high, reflecting the fact that they take power at low voltage and require costly low-voltage distribution investments, and have low load factors. Average prices for very large industrial customers are much lower reflecting the fact that they take power at high voltages and have higher load factors. Political considerations and self-generation options also affect these rate structure formation, a process that can be quite byzantine. Increasingly, U.S. utilities have offered larger customers time-of-day rates and interruptible rates.

Retail rates determined by state commissions using this type of regulatory process vary widely across the U.S. Indeed, they vary widely within individual geographic regions of the U.S. Table 1 displays the average residential and industrial rates for a cross-section of U.S. utilities located around the country. The rate variations reflect in part regional variations in fuel and construction costs, differences in environmental requirements and differences in the mix of customers, load factors, and service area density. However, they also reflect historical differences in the perceived economics of nuclear capacity and associated commitments to this technology, state regulatory policies toward cogeneration and small power production facilities (see below), and variations in excess capacity in 1992.

c. Economic Regulation: Federal

Until 1935, the federal government played almost no role in the regulation of electric utilities. However, two pieces of legislation passed in 1935 created such a federal regulatory role. The Federal Power Act of 1935 extended federal regulatory jurisdiction to interstate "wholesale" power sales and interstate transmission service. Wholesale power sales are defined as sales of electricity by one utility to another utility. Transmission service has traditionally been defined in the same way to cover sales of transmission service from one utility to another utility to support an associated power transaction. The Federal Power Commission (now the Federal Energy Regulatory Commission -- FERC) was given the responsibility to implement these regulatory responsibilities.[17]

Until recently, the economic regulatory role of the FERC was fairly modest. Initially, the FPC's (now FERC) economic regulations focused primarily on sales made by vertically integrated utilities to unintegrated municipal distribution utilities to which they provided "full requirements service."[18] A typical vertically integrated utility's wholesale requirements load generally was a small fraction (e.g. less than 10%) of its total load (retail plus wholesale), however. The FPC/FERC used cost of service principles similar to those used by state commissions (discussed above) to determine the rates that could be charged to these wholesale requirements customers. The FERC also imposed a de facto obligation to serve these customers by requiring FERC approval for termination of service.

The FERC also regulates wholesale "coordination" transactions between integrated utilities. These include short term trades of energy between interconnected utilities, capacity transactions, and power pooling and and inter-control area coordination arrangements. Although these arrangements were technically regulated based on accounting costs, the FERC allowed a considerable amount of discretion to the parties to negotiate mutually attractive arrangements when "real utilities" where on both sides of the transaction. Wholesale transactions of this type were of negligible importance for many years. However, as interconnection, coordination, and power pooling expanded after World War II, wholesale transactions became an increasingly important way for the hundred and fifty or so vertically integrated utilities to take advantage of economical opportunities to substitute low cost supplies made available by third parties for their own internal high cost supplies and to reduce the costs of maintaining reliability.

It is important to understand, however, that until recently, vertically integrated utilities did not make investments in new generating facilities to serve this wholesale "coordination" market.

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[17]The Federal Power Commission has other responsibilities governing the electric power system as well

[18]FERC has always had a bias toward protecting the small municipal distribution systems against the real or imagined efforts to exploit them by surrounding IOUs.

Rather, sales in this market were typically from capacity built to serve retail customers, but which was temporarily excess to the needs of these customers. Moreover, FERC has no certification or approval authority over generation or transmission facilities and until 1992 did not have the authority to order utilities to provide transmission service to other utilities that might have wanted to shop in the wholesale market. The coordination market evolved primarily to facilitate the economical operation of existing generating facilities based on regional rather than only individual utility supply and demand conditions and to reduce reserve requirements by substituting emergency support arrangements with neighboring utilities for stand-alone reserve capacity. These factors, combined with reliance on cost of service regulation made it impossible for an independent generating sector to emerge in the U.S. prior to recent years.[19]

FERC also has exclusive jurisdiction over the terms and conditions of interstate transmission arrangements.[20] Since retail customers have been served exclusively by their local utility and the utility sells them a bundled product, the transmission arrangements that have been the focus of FERC's regulatory efforts have generally been in conjunction with wholesale power transactions. FERC has relied and continues to rely today on very crude pricing arrangements for transmission service. Transmission service is generally provided by utilities on a point to point basis, but using a "postage stamp" rate based on the average embedded cost of its transmission network.[21] FERC recently expanded its accepted methodology to include some incremental cost pricing principles, expanded the types of transmission services it expects utilities to provide, and is currently in the process of reevaluating how it establishes prices for transmission service.[22] More on this below.

Although FERC's role in the regulation of the electric power industry was relatively modest

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[19]The interaction of these institutions as an impediment to the evolution of an independent wholesale generating sector is explained in Joskow (1989), p.133 and 139.

[20]Virtually any transmission or wheeling transaction which uses high voltage transmission facilities is likely to be deemed to be an interstate transaction even if the buyer and the seller are located in the same state.

[21]See Joskow (1993a).

[22]Federal Energy Regulatory Commission, *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, June 30, 1993.

until recently, this role has and is likely to continue to increase as competition evolves. There are two interrelated reasons for this. First, as an independent generation sector emerges, generating services will increasingly be sold to distribution utilities under contract rather than being produced solely from generating facilities they own (vertical integration). These sales will be FERC jurisdictional while internal production is state jurisdictional. Second, as both unbundled wholesale and retail transactions increase with more competition, transmission and related control area services will be provided on an unbundled basis. The bulk of these transactions are likely to be FERC jurisdictional as well. Furthermore, the organization, access to and pricing of transmission and control area services will be of fundamental importance for the nature of the *performance* a competitive electricity sector. These "grid issues" are of special concern in the United States where we have a highly balkanized grid made up of over 140 interconnected control areas. The system has held together reasonably well as a result of the evolution of cooperative arrangements between utilities that did not compete much with one another and that could rely on cost of service regulation to "true up" the failure properly to price transmission and control area services and to deal with a variety of free rider and externality problems that emerge on a synchronized AC network with many interconnected independent control area operators.

In 1935 Congress also passed the Public Utility Holding Company Act. This law was motivated by a variety of financial and regulatory abuses that allegedly were associated with the large multistate public utility holding companies that emerged in the U.S. during the 1920s and early 1930s. The provisions of the Public Utility Holding Company Act are complex and I will not go into all of them in detail here. Let me touch on few provisions of PUHCA (pre-1992) that were of special concern from the perspective of the evolution of a competitive electricity sector.

A public utility holding company is defined as an entity that owns or controls one or more public utility companies. Under U.S. law, a public utility company in turn is essentially any private entity that generates, transmits, or distributes electricity to the public. A public utility holding company is subject to a variety of regulations governing its organizational structure, the geographic expanse of its activities, its financial structure, and the businesses that it can engage in. These regulations are administered by the Securities and Exchange Commission (SEC). Exemptions from the regulations are available for public utility holding companies whose utility subsidiaries primarily provide service in a single state and whose total business activities are primarily in the utility sector. The bulk of the electric utilities in the U.S. are either not holding companies[23] or are organized as exempt holding companies. There are about a dozen registered multistate holding companies that are subject to the full force of the regulatory provisions of the Act. These entities must operate as integrated systems, effectively limiting their activities to a single geographic area, and are limited to lines of business that are functionally related to their utility businesses.[24]

The original provisions of the Holding Company Act created significant barriers to the creation of an independent generating sector made up of companies which owned generating facilities around the country through a holding company structure. A non-utility (e.g. Bechtel) that sought to own two or more independent generating facilities would be deemed to be a public utility holding company and could become subject to regulation under the Act. As a public utility holding company it would face restrictions on the non-utility businesses it could enter into and the geographic distribution of its generating facilities. This effectively kept non-utilities out of the electricity supply business, except to supply their own internal needs. An exempt utility holding company could developed independent generating facilities, but if these facilities were located in states other than the states where it provided distribution service it could lose its single state exemption and be required to register as an interstate holding company. This is turn would subject it to new regulations governing the lines of business it could enter into and limit its ownership of generation to areas interconnected with its own system. Finally, registered holding companies could have, in principal, develop independent generating facilities, but only in their own regions, and subject to stringent SEC financing regulations governing debt/equity ratios. These regulations were fairly potent barriers to the entry of independent generating companies into the U.S. electricity sector.[25]

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[23]State laws also often restrict the creation and activities of public utility holding companies.

[24]PUHCA also imposed significant impediments on U.S. public utility holding companies seeking to make investments in generation, transmission, and distribution assets outside of the U.S.

[25]Although the primary barriers were IOU preferences for a vertically integrated structure and prevailing cost of service regulations which limited the economic opportunities for merchant plants.

PUHCA also restricted the ownership of foreign utility assets by U.S. utilities through a holding company structure and restricted ownership of U.S. electricity supply assets by foreign holding companies. As I will discuss presently, removing many of these barriers to the entry of IPPs was a major motivation for the PUHCA reforms included in the Energy Policy Act of 1992.

WHOLESALE MARKET COMPETITION

The term "wholesale market" in the U.S. refers to power and transmission service transactions in which the buyer is a distribution utility (unintegrated or integrated) and the seller is another utility (including independent generating companies). That is, it involves sales by generating entities to distribution entities for resale to retail customers. The wholesale market does not include direct sales of electricity to retail customers even if these customers are very large and purchase power at high voltages. The wholesale market has been of increasing importance in the electric power industry in the U.S. for decades, but because of the vertically integrated structure of the industry, the existence of numerous interconnected control areas, and the nature of price regulation, it has had a very special structure.

a. Wholesale Market Competition Prior to the QF/IPP Era

The wholesale market that has evolved in the U.S. since World War II is best understood by focusing on two market segments. The first segment is what I will refer to as the *requirements customer* market. The second segment is the *coordination* market segment.[26] Let me discuss each in turn.

i. Wholesale Requirements Services

The requirements customer market involves buyers who were unintegrated (largely municipal and cooperative) distribution companies. Historically, they purchased their "full requirements" for power from a proximate vertically integrated utility whose transmission network often surrounded

[26]This distinction was used explicitly by the FERC in its Notice of Inquiry into wholesale market transactions in 1985. *Notice of Inquiry re Regulation of Electricity Sales-for-Resale and Transmission Service*. 31 FERC 61,376 (1985).

them. The terms and conditions of these full requirements contracts or tariffs generally provided that the integrated utility would plan for the needs of these distribution system customers, would supply them with all the power they needed to meet their retail customers' load, and would charge prices based on the average cost of supply, including capital charges associated with historical investments. As I have already discussed, the associate prices for services are regulated by FERC using traditional cost of service/rate of return regulatory principles. Basically, the rates for these customers were determined in essentially the same way as the rates charged to large industrial customers, except the regulatory forum was different. Since wholesale requirements customers generally accounted for a small share of a utility's load, they essentially rode along on the tail of the state regulatory process governing planning, resource procurement, certification, etc., and FERC tried to use symmetrical cost of service ratemaking procedures so that costs did not get "trapped" between state and federal regulatory procedures.

Some wholesale requirements customers complained about being forced to take all of their bulk power requirements under regulated tariffs from the local utility to which they were "captive." Some wanted the opportunity to plan, own and operate some or all of their own generation, either individually or collectively with other utilities (that is they wanted to become vertically integrated).[27] Others wanted the option to acquire some or all of their bulk power requirements from other utilities in their regions. In either case, the municipal distribution companies required access to the local utility's transmission grid to "wheel" generation to the distribution system and to integrate dispersed generating facilities efficiently. However, while the utilities providing requirements service did not have an exclusive right to serve municipal utilities embedded in their networks, they also had no regulatory obligation to provide these entities with access to their transmission networks since the Federal Power Act did not give the FERC the authority to order utilities to provide transmission service.

In order to get access to transmission systems of their host utilities wholesale requirements

[27]The availability of tax free financing to municipal utilities made ownership of generating facilities more economical in some cases than purchasing power from a private utility whose financial instruments were subject to income taxes.

customers turned to the antitrust laws for help. The Atomic Energy Act contained antitrust provisions that made it possible for the Atomic Energy Commission (now the Nuclear Regulatory Commission) to attach antitrust conditions to nuclear plant licenses. Municipal utilities often used this licensing process to obtain license conditions that required the utility to open up its transmission system based on reasonable and non-discriminatory terms and conditions to enable them to acquire some or all of their power requirements from competing supply sources. Municipal and cooperative utilities also brought suits under the federal antitrust laws to obtain access to "essential" transmission facilities.[28] Furthermore, once a utility began to offer transmission service to some wholesale requirements customers, FERC was able to use its authority to bar undue discrimination to extend these services to others.

By the mid-1980s, the typical municipal or cooperative distribution utility had obtained extensive transmission service from its host utility. In places like California and Florida, where there was extensive litigation, municipal utilities typically were purchasing the bulk of their energy from competing third parties or from generating facilities they owned rather than from the host veritically integrated utility by the mid-1980s. While there have been ongoing disputes about the terms and conditions of these services and the quality of the services available, by the mid-1980s unintegrated distribution utilities that wanted to were able to acquire the bulk of their requirements from competing suppliers, relying on their host utility as a backup for any requirements that they could not fill with better deals with competing suppliers. Through various coordination and integration arrangements with these host utilities, previously unintegrated distribution companies have been able to integrate multiple generating sources and make long term and short term purchases from competing suppliers. There is extensive competition among vertically integrated utilities to serve the bulk power needs of these utilities.

Despite these changes over the last two decades, so-called transmission dependent utilities (TDUs) have continued to complain about the reluctance of some host utilities to provide them with all of the transmission and related services they desired. Their host utilities in turn have complained

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[28] *Otter Tail Power Company v. United States*, 410 U.S. 366 (1973) and Joskow (1982).

that the prices they are permitted by regulators to charge for residual power requirements and transmission service are too low and are structured in a way that encourages free riding by these customers. Until relatively recently, the primary agitation for expanding competitive opportunities at the *wholesale* level, in particular imposing more extensive obligations on utilities that operate transmission networks to provide access to them based on reasonable terms and conditions, have been municipal and cooperative TDUs. Their objectives were not always meritorious, however, and the mixture of competitive opportunities with regulated rates and service obligations for generation and transmission service created numerous opportunities for inefficient regulatory gaming and rent seeking behavior.

The markets for wholesale *coordination* services developed largely out of the needs of proximate vertically integrated utilities which operated their own control areas to take advantage of short run opportunities to exchange energy and capacity with neighboring utilities in order to reduce the overall cost of operating their systems and to reduce the costs of maintaining reliability through reserve sharing and emergency support agreements. Utilities throughout the United States have routinely engaged in hourly exchanges of energy so that low cost generators in one control area that would otherwise be idle can generate electricity to replace power that would otherwise have been produced by a more costly generator located in another control area. In a sense, the coordination markets developed as market alternatives to central economic dispatch of generators that would otherwise be dispatched independently by each control area.[29] The reliance on economy energy transactions expanded very significantly after 1973 as large gaps emerged between oil, gas, and coal prices. Over time, the range of products available in the coordination markets has also expanded. Contractual arrangements with longer durations emerged and vertically integrated utilities came to rely on medium term capacity and energy contracts to allow them to put some of their generating facilities in reserve status (reducing non-fuel operating and maintenance costs) and to defer construction of new generating facilities. These longer term capacity and energy contracts were significantly different from the very short term coordination arrangements from which they emerged.

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[29] In New England, New York, and the PJM areas, power pools with central economic dispatch were substitutes for market coordination.

Requirements customers also increasingly came to rely on contracts with competing integrated utilities to supply some or all of their bulk power needs. These developments have eroded the boundaries between requirements and coordination services markets.

It is important to understand, however, that these coordination markets, have been primarily "excess capacity" markets. That is, utilities competed with one another to make sales to other utilities (including unintegrated distribution companies) out of capacity originally built to serve their retail franchise load (so-called "native load customers") pursuant to state cost of service and certification regulations. The capacity might be excess to their needs for an hour, a day, a year, or even ten years. If they can sell the associated energy and capacity to other utilities at any price greater than the operating costs of the facilities, the net profit from these transactions can be used to reduce retail rates or to enhance the utility's overall profits.[30] However, utilities generally did not build new generating facilities in anticipation of wholesale coordination market revenue. Moreover, even for short term energy transactions, the bulk of a utility's generating capacity did not compete directly in the market since it was consumed internally.[31] Finally, the evolution of these coordination market institutions has depended heavily on cooperative arrangements between utilities that did not compete with one another for the vast bulk of their revenues and profits --- revenues and profits received from retail service that each utility supplies exclusively.

FERC regulation of coordination transactions has provided fairly good incentives to induce utilities to consummate short and medium term transactions when their are gains from trade. While these transactions were always technically subject to cost of service regulation, FERC applied cost of service regulation fairly flexibly. FERC gave utilities a lot of discretion in how they "cost-justified" individual transactions and permitted explicit shared savings arrangements. The fact that

[30]State regulatory treatment of revenues and costs from wholesale transactions has varied very significantly. Many states require at least some of the net profits from such transactions to be used to reduce the rates that would otherwise be charged to retail customers.

[31]Of course it competed indirectly since if it were cheaper to buy from third parties rather than to produce from integrated facilities to serve retail customer needs that is the choice regulators expected utilities to make. And while such behavior was probably typical for hourly transactions, regulatory distortions may have affected decisions to mothball or retire existing generation in favor of purchasing cheaper replacement resources in the market, or to defer construction of new capacity by purchasing from another utility.

FERC did not apply rigid cost of service formulas to regulate these rates is a major reason why the coordination market grew so much during the 1970s and 1980s in response to growing regional differences in marginal operating costs and supply/demand balances. Excess capacity and state regulatory barriers to investments in new facilities increased both the supply and demand for medium and long term capacity and energy transactions as well. But basically, wholesale market competition served primarily to "smooth out" the short term operating inefficiencies that would otherwise be associated with a long term generating capacity autarky policy applied by each individual vertically integrated utility.

It is widely recognized that by the 1980s, the coordination markets were doing an excellent job optimizing the short run utilization of generating facilities over wide geographic regions through hourly, daily, and weekly transactions. However, the wholesale market was relied upon much less by utilities to make it possible to mothball or close existing facilities before the end of their accounting lives and even less as a substitute for owning their own generating capacity to meet the long term needs of their retail distribution franchise customers. This was in part a consequence of regulatory incentives and in part a consequence of the widespread belief that vertical integration was necessary to finance and effectively integrate large costly generating facilities.

b. The QF/IPP Era

Title II of the Public Utility Regulatory Policy Act of 1978 (PURPA) stimulated major changes in wholesale power markets and public policy toward competition and vertical integration in the U.S. electric power sector, although its most significant effects were not felt until the late 1980s. Prior to PURPA there was effectively no unintegrated independent generating sector in the U.S. The bulk of the generation was either owned by vertically integrated utilities or fully contracted under long term accounting cost-based contracts to distribution utilities. PURPA began the process of creating an independent generation sector and the supporting market and regulatory institutions to create a competitive market for new generating resources.

The primary motivation for PURPA was to encourage improvements in energy efficiency through expanded use of cogeneration technology and to create a market for electricity produced from renewable fuels and fuel wastes. It was not motivated by a desire to restructure the electricity sector and to create an independent competitive generation sector. However, it turned out to have effects significantly different from what was intended when it was passed. PURPA provided that all utilities engaged in the distribution of electricity were required to offer to purchase electricity produced by certain qualifying cogeneration and certain small power production facilities using renewable fuels (these facilities are generally referred to as "QFs"). Utilities had to offer a purchase from QFs at a price that reflected the *costs avoided* by the utility by purchasing from the QF rather than by generating itself. Cogenerators could use some of the electricity they produced to serve the electrical load of a host industrial or commercial facility and sell the excess back to the utility or sell their total output to the local utility. PURPA did not authorize QFs to make sales directly to retail customers, but only to utilities, and with a few exceptions state laws generally do not permit direct sales by QFs to retail customers either.

Thus, PURPA maintained the traditional model of a utility as a "portfolio manager" that must acquire generating resources to serve the needs of its retail franchise customers which it serves on an exclusive basis. However, rather than meeting this obligation only by owning and operating its own generating facilities, utilities now had to look to QF supplies to meet their needs as well. Moreover, PURPA provided exemptions to the Public Utility Holding Company Act to QF owners. This made it possible for a large number of non-utility companies to enter the electric generation business as owners of QFs.[32]

After PURPA was passed in 1978, FERC and then the states proceeded to develop regulations to implement it. FERC delegated primary responsibility to the states to specify detailed implementation regulations to govern the relationship between utilities and QFs subject to FERC's avoided cost regulations and PURPA facility qualifying criteria. Utilities began to enter into contracts with QFs in the early 1980s and significant quantities of QF capacity began to come on line after 1985.

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[32]Utilities and public utility holding companies were allowed to own no more than a 50% interest in a QF However, some of the most successful QF development and operating companies are subsidiaries of utility holding companies (an exempt holding company could retain its single state exemption and still have interests in QFs located anywhere in the U.S.).

The experience with PURPA since then has been a mixed bag. On the one hand, significant investments in QF facilities have been made since PURPA was passed and QFs now account for roughly 50,000 Mw of generating capacity. Figure #1 displays the growth in production by non-utility generators (NUGs), which are primarily QFs, over the last 25 years. We have seen a very rapid rate of growth in electricity supplied by NUGs since 1985. In the last couple of years, QFs and other non-utility generation sources have accounted for a larger fraction of generating capacity additions than have vertically integrated utilities. The power from these facilities is generally purchased pursuant to long term *take and pay* incentive contracts in which prices are established (very roughly) based on (imperfect) measures of market values at the time the contract is signed rather than each individual suppliers' costs and which have substantial incentives for cost control and performance. Many of these facilities have excellent performance records.

It is quite clear that entities which are not utilities can build and operate generating facilities as efficiently as can utilities.[33] Indeed, QF developers provided a major stimulus to advances in CCGT technology and have been successful in applying this technology very efficiently. On the other hand, the regulations governing QF procurement in a number of states forced utilities to buy too much QF capacity at too high a price. Part of the problem was a natural consequence of the inherent difficulties faced by regulators in determining a utility's expected avoided costs for use in a 20 to 30 year firm power contract.[34] In response to these problems, many states shifted from the administrative determination of avoided cost-based prices at which utilities had to buy all QF power that was offered, to competitive bidding programs in which utilities estimate their capacity needs and then put these needs out for competitive bids.[35] Unfortunately, these bidding programs became embedded in complex and highly politicized "integrated resource management" processes in which numerous considerations other than cost were taken into account to determine what utilities would

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[33]Although most QFs are relatively small compared to utility units and are not fully dispatchable.

[34]The contracts typically fix a capacity payment that does not change over the life of the contract and an energy payment that may be fixed or vary with fuel prices.

[35]These developments are discussed in more detail in Joskow (1989).

have to buy from whom at what price. Especially in states in the Northeast and in California these planning processes created even further pressures for utilities to purchase capacity that was not needed at prices that were too high.

Perhaps the most important legacy of PURPA has been its effects on prevailing views about vertical integration between generation service and transmission and distribution services. The initial "model" that guided PURPA envisioned utilities continuing to own and operate the bulk of the existing and new generation resources. QFs, it was thought, would be largely fringe suppliers. As it turned out, the supply of QF capacity was larger than had been anticipated, the need for new generating capacity significantly lower than anticipated, and unexpected low natural gas prices and the associated heavy reliance on CCGT technology significantly reduced utility advantages associated with building and operating large coal and nuclear units. QFs with long term contracts with utilities were also able to finance their plants with a lot more debt than utilities could utilize, reducing the private after tax costs of financing these facilities.[36] As a result, utilities were increasingly in a position where they were facing quantitatively significant tradeoffs between building their own generating facilities or buying from QFs. Complaints about conflicts of interest and abusive self-dealing began to be raised. Most importantly, as the QF business grew, industry analysts and the obvious interest groups began to argue that the supplies of non-utility generation should not be limited to QFs, with their technology, fuel, and size limitations,[37] but should be opened up to all potential suppliers of generation resources. It was argued further that utilities could play the most effective role as "portfolio managers" for their retail customers by carefully examining the attributes of *all sources* of generation --QFs, non-QF independent power producers (IPPs), third-party utility supplies, as well as utility-owned generation -- choosing the mix of power by contract and vertical integration that was "least cost." The associated costs of power would be passed along to retail

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[36]Obviously, these plants are being financed partially off of the balance sheets of the utilities that sign the long term contracts. The lower financing costs are largely an illusion since the costs of utility financing rise to reflect the increased liability associated with the long term contracts.

[37]Although many suppliers were able to develop projects that met PURPA's technical requirements, but not its spirit. These facilities were known as "PURPA machines."

customers served by the utility-buyer on an exclusive basis in much the same way as would the costs of utility-owned generation.

Thus, by the late 1980s, the traditional view of vertically integrated utilities providing for their retail customers' needs by owning and operating generation, transmission, and distribution facilities was under serious attack. Competition at the wholesale level to meet a utility's incremental generation needs was becoming widely accepted. The benefits of vertical integration were being questioned and the potential for relying more on power by contract purchased in competitive wholesale markets where QFs, IPPs, and utilities with excess capacity could compete to supply a utilities incremental generation needs was attracting increased attention. Interest in regulatory reforms to encourage entry of QFs and IPPs was growing, as were concerns about potential self-dealing problems between a utility as buyer of generation resources from others and the utility as a supplier of competing generation through the construction of new facilities.

c. FERC's Market Based Pricing Initiatives

The development of competitive wholesale generation markets in which all generation sources could compete faced a number of regulatory barriers. First, unlike QFs covered by PURPA, sales by IPPs or by utilities with excess capacity were subject to FERC regulation under the Federal Power Act. FERC required prices, especially for sales from a specific facility, to be "cost justified." This in turn meant that the prices charged would have to adhere to traditional cost of service/rate of return principles. These ratemaking principles were consistent with regulating a utility serving a legal monopoly franchise and subject to a prudent investment standard. However, they were not compatible with the kind of take and pay incentive contracts upon which QFs increasingly relied or on speculative market entry by IPPs.[38]

In 1988, FERC began to reconsider its pricing regulations in an effort to encourage entry of non-QF IPPs into the electricity sector, as well as to encourage utilities with excess capacity to sell

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[38]These pricing principles are more compatible with very long term take or pay contracts of the type that characterized the few "independent" generating facilities that were operating in the U.S. prior to PURPA.

it to third parties under long term contracts.[39] Specifically the policy staff and ultimately the Commission wanted to develop regulations that would effectively allow suppliers without significant market power to sell generation services to utilities at "market based rates" that were not tied administratively to the supplier's accounting cost of service.[40] That is, the prices for sales by generators without market power would be deregulated (or alternatively that the market would be relied upon to ensure that the resulting prices were "just and reasonable").

The evolution of FERC's market-based pricing rules has focused on three sets of interrelated issues. First, whether the supplier has significant market power in the supply of various generation product markets.[41] Second, whether the supplier is able to exploit relationships with a regulated electric utility to cross-subsidize the cost of sales or to otherwise favor an affiliated supplier. Third, whether the supplier has market power over the provision of transmission service in the relevant market where the power transactions took place.

In evaluating generation market power FERC has looked at the number of bidders offering to supply in competitive solicitations, the market share of the supplier for various generation services, and ease of entry. Market shares depend on the geographic market in which competition is assumed to take place, which in turn depends on the availability of transmission service.

FERC's concerns about cross-subsidization and self-dealing have meant that applications for market-based pricing by utilities and utility affiliates are given special scrutiny. Evidence demonstrating that adequate cost accounting and cost-separations between regulated utility activities and unregulated sales of generation must be presented to the Commission. Transactions involving

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[39]In 1988 FERC issued three controversial Notices of Proposed Rulemaking (NOPRs) that dealt with wholesale power and transmission service pricing as well as the regulatory treatment of independent power producers. FERC never issued final rules following the comments and controversy over these NOPRs. However, it subsequently proceeded de facto to implement many of the policies contained in the NOPRs through case by case rulings on filings presented to the Commission.

[40]A good summary of the evolution of FERC's policies regarding market based pricing prior to the Energy Policy Act of 1992 can be found in B. Tennenbaum and S. Henderson, "The History of Market-Based Pricing," *The Electricity Journal*, December 1991.

[41]FERC has focused on the seller's "unilateral" market power rather than whether the overall market is oligopolistic leading to prices significantly above some reasonable benchmark competitive level.

sales of power at market-based rates by a generation supplier to an affiliated regulated utility would require a showing that no preference could be given to the affiliated supplier. I am not aware of any "self-dealing" transactions at market-based rates that have been approved by FERC, however.

Finally, utilities seeking to make sales of generation service at market-based rates must also demonstrate that they cannot exercise market power through their control over transmission facilities. As I will discuss further in the next section, prior to the passage of the Energy Policy Act of 1992, FERC has used its authority to grant market-based pricing treatment as a lever to get utilities to provide "open access" to their transmission systems.[42] FERC has not, in fact, developed a coherent methodology to evaluate whether a utility supplier of generation service can actually exercise market power in downstream generation markets as a consequence of its control over regulated upstream transmission service. Rather it has simply assumed that a utility that operates any transmission facilities at all has market power even if there are competing sources of transmission service to support transactions in the relevant market. As I will discuss presently, FERC used the carrot of market-based pricing to get utilities to "voluntarily" provide access to competing suppliers to use their transmission systems to make sales to wholesale customers.

As FERC's market-based pricing regulations have evolved, independent power producers and unregulated utility-affiliates making power sales remote from their affiliated regulated utility retail service territory have had little difficulty obtaining market-based pricing authority from FERC. FERC has also accommodated the entry of power brokers which have sought to enter the market to arrange power transactions between one of more sellers of power and specific purchasing utilities with a minimum of regulatory obligations. On the other hand, utilities and utility affiliates seeking market based pricing authority to sell in or near their service areas must provide adequate "open access" transmission service to other buyers and sellers. As discussed further below, the nature of the services that must be provided to satisfy FERC's open access criteria have expanded significantly in the last year or so as FERC began to implement its responsibilities under the Energy Policy Act of 1992 (EPAct92).

[42]Recall that prior to this law, FERC had only limited authority to order utilities to provide transmission service to third parties.

By 1991, FERC had been largely successful in removing federal regulatory barriers to the entry of independent power producers that were not QFs under PURPA. In this way, it created opportunities for buyers to seek competitive bids from such entities and for these entities to build facilities to supply power to willing buyers. However, FERC had absolutely no authority to force utilities to *purchase* electricity from non-QF independent power suppliers or from other utilities with excess capacity. Unlike QFs under PURPA, there was no federal requirement to purchase from these entities. For most utilities, generation resource procurement regulations governing what a utility builds or contracts for is subject to state rather than federal jurisdiction.[43] And the enthusiasm of the states for encouraging utilities to rely on all-source competitive procurement arrangements to choose the lowest cost supplier regardless of ownership arrangements has varied widely. States like New York, Massachusetts, Virginia, and Florida have encouraged utilities to take an "all source" competitive procurement perspective. However, many other states have been more cautious about moving further away from the traditional vertical integration model. Even California included only QFs in its most recent solicitation for generating capacity.

d. FERC's Initiatives to Increase Access to Wholesale Transmission Service Prior to EPAct92

A potential impediment to the development of a fully competitive wholesale market was restrictions on the availability of transmission and related network services owned and controlled by vertically integrated utilities. For a utility buyer and a generation seller to consummate a transaction, transmission service, interconnection, control and dispatching services had to be provided. This was not a serious problem when the supplier was a QF or IPP located in the buyer's control area as long as the buyer was interested in consummating the purchase. However, a supplier of generation services required transmission and related network services from other utilities if its generating plant was located outside the purchasing utility's control area. Under the Federal Power Act, however, FERC could not order a utility to provide interstate transmission services or related network services

[43]Procurement decisions by some affiliates of public utility holding companies may be FERC or SEC jurisdictional, however.

or to build facilities to support such a transaction. While FERC could regulate the prices charged for transmission service, and in this way control monopoly pricing for transmission, there was concern that "intervening" utilities would deny service or limit the services available to competing suppliers of generation service so that they could protect their markets for wholesale power supplied by their own generation facilities by restricting competition. The potential problems here were compounded by the balkanization of the interconnected networks with pieces owned and operated by many different utilities in most regions since an economical transaction could involve several control areas on end to end or parallel paths between the generation source and the load.

The FERC staff wanted utilities to provide "open access" to their transmission system to all third party buyers and sellers based on non-discriminatory terms and conditions. However, it had no authority to order utilities to provide such services. Absent statutory authority to require utilities to provide non-discriminatory transmission service, FERC began to use a carrot and stick approach to encourage utilities to "voluntarily" file open access transmission tariffs. In particular, FERC began to condition its approval of mergers between vertically integrated utilities on their filing of open access transmission tariffs.[44] As discussed earlier FERC also began to tie the availability of "market based pricing" to utilities to their making "voluntary" open access transmission filings. Prior to EPAct92, an adequate open access tariff provided firm and non-firm point to point service at cost-based rates. As I will discuss presently, FERC's view of what services must be included in an acceptable open access tariff has expanded over time.

This carrot and stick approach did lead a number of utilities to file open access transmission tariffs. However, this approach had its limitations. While merger activity in the electric power industry has increased significantly in the last few years, it has not yet become a merger wave. In addition, the value of market-based pricing authority was not very large to many utilities because

[44]For example, the merger of Pacific Power and Light and Utah Power and Light (1989) and merger involving Northeast Utilities and Public Service Company of New Hampshire (1991). The argument was that the mergers created or enhanced market power in one or more markets and that by offering to provide "open access" transmission service to third parties mitigated such market power. More recently, FERC has been willing to waive a hearing on market power issues if the parties have an approved open access transmission tariff in place. For example, the merger of Entergy and Gulf States Utilities (1993) and the merger of Public Service of Indiana (PSI) and Cincinnati Gas and Electric (1994).

existing FERC regulations gave utilities significant pricing flexibility in transactions with other vertically integrated utilities.

Another impediment to voluntary provision of transmission service has been the regulatory rules governing how transmission and control area services are priced. Just as was the case for generation, utilities generally built transmission capacity to serve the needs of their retail franchise customers. They sold transmission capacity to third parties on a firm and non-firm basis when capacity was available from transmission facilities that were not fully utilized to serve the needs of these customers. Moreover, utilities had few financial incentives to offer transmission service to third parties. The costs of transmission facilities were included in the utility's rate base and the associated capital and operating costs included in retail rates. When a utility made sales to third parties, the bulk of the revenues received were (de facto) eventually credited back against retail rates. Moreover, FERC placed a ceiling on the price that a utility could charge for transmission service to third parties equal to the average embedded cost of transmission facilities per Mw of system peak load. The service was generally point to point, but the price did not vary with the location of the load or the generator. When the revenues calculated for the transmission transaction exceeded the full "incremental costs" of the transaction, offering the service could reduce retail rates (slightly) and, through the workings of regulatory lag, perhaps yield some profit to the transmitting utility. When transmission service involved constrained paths, the full incremental costs of the transaction could exceed the revenues produced from the transaction, providing the service would lead retail rates to rise. Moreover, because construction of new transmission facilities has become more and more difficult due to environmental opposition, utilities are reluctant to offer transmission capacity that is temporarily excess to their needs to third parties on a long term basis. The political and regulatory costs of building major new transmission facilities are perceived to be larger than the revenues gained from selling off some temporarily excess transmission capacity.

By 1990, FERC's transmission pricing rules were widely recognized as being seriously deficient from an efficiency, incentive, and equity perspective. In the *Pennsylvania Electric* case

FERC defined a new pricing rule.[45] Utilities could charge the higher of embedded cost or incremental cost and, as a result, would not be penalized for, or provide subsidies to third parties requesting transmission service. However, FERC provided little guidance regarding how the relevant incremental costs should be calculated. FERC's pricing rules have been criticized by transmitting utilities for providing inadequate compensation for the use of common network facilities when the transactions requires expansion of a constrained interconnection. They have been criticized by transmission dependent utilities as requiring excessive payments. They have been criticized by academics for ignoring completely the most basic economic principles that should guide transmission service pricing to promote the efficient location and use of generating facilities and the efficient expansion of transmission facilities.[46] Despite these criticisms, FERC continues to rely on this "higher of" rule.

FERC now appears to recognize that, especially in light of its expanded authority under the Energy Policy Act of 1992 (see below), transmission pricing reforms are likely to be desirable to support expanded competitive opportunities in wholesale markets. FERC recently initiated a proceeding to examine alternative pricing concepts and a policy paper based on the comments received in this proceeding is due out in Fall 1994.[47] However, at this point it appears that FERC is reluctant to mandate any specific "innovative" transmission pricing methodology, or even to encourage individual utilities to come forward with their own pricing proposals. Instead, FERC is encouraging the formation of Regional Transmission Groups (RTGs) which will take responsibility for regional planning of transmission facilities, the provision of information about transmission capacity and costs, and ultimately comprehensive pricing of transmission service within the relevant

[45]58 FERC 61,278 (1992)

[46]Joskow (1993a), Hogan (1993), and Hunt and Shuttleworth (1993).

[47]*Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Federal Energy Regulatory Commission, Docket No. RM93-19-000. June 30, 1993. Technical Conference held April 8 and 15, 1994.

regions.[48] These regional groups could, in principle, help to solve the problems associated with the balkanization of the regional networks. Again FERC is taking a carrot and stick approach. It wants RTGs to better coordinate the parties that own interconnected generation and transmission facilities in each region. The carrot is that FERC will give more deference to innovative pricing proposals that come from an RTG composed of a broad cross-section of the IOU, municipal utility and non-utility generation interests in the region. The RTGs that have been announced to date, however, have not attempted to deal with transmission pricing issues and FERC's view that it can avoid getting into the difficult details of transmission and control area service pricing is of questionable merit.

e. The Energy Policy Act of 1992 (EPAct92)

By 1990, the forces unleashed by PURPA and FERC's initiatives on market based pricing and independent power producers[49] had led those interested in exploiting the associated competitive market opportunities to seek relief from the statutory restrictions on the entry of IPPs. The initial stimulus for statutory reforms came from utilities and non-utilities which were interested in getting into the (non-QF) IPP business in the U.S. and abroad. In order to do so, they required changes in the Public Utility Holding Company Act that would make it possible to enter the IPP business through a holding company structure without triggering regulation under the Act. Such regulation effectively precluded non-utilities from entering the generation business and restricted the ability of utilities to do so. Basically, they sought an exemption from the Act's regulatory requirements that would otherwise have been triggered merely as a consequence of ownership of an IPP-type generating facility.[50] They also sought repeal of PUHCA's restrictions on ownership of foreign

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[48]Federal Energy Regulatory Commission, *Policy Statement Regarding Regional Transmission Groups*. July 30, 1993.

[49]FERC had also issues regulations that reduced the administrative burdens placed on true independent power producers.

[50]Existing registered holding companies also wanted changes in the Act that would allow them to develop IPP in areas outside of the regions where they presently operated and associated system integration requirements.

utility assets. The initial efforts for statutory reform focused on getting a narrowly focused amendment to PUHCA.

Many of the opponents of PUHCA reform where also utilities. The proposed reforms were controversial within the industry because of concerns that once the fairly narrow reforms were taken up by Congress, various interest groups would use the legislative process as an opportunity to make other changes in PUHCA and the Federal Power Act that many utilities would find to be of concern. In particular, there was fairly widespread concern within the industry that a modest reform initiative that focused on further development of IPPs and competitive wholesale generation markets would undermine the existing vertically integrated structure of the industry, make it more difficult for utilities to own and operate generating facilities used to serve their retail customers, facilitate municipalization of IOU distribution franchises, and lead to changes in FERC's transmission authority that would ultimately undermine the utility's regulated monopoly over retail customers. Thus, opponents of reform within the IOU sector felt that the modest PUHCA reform initiative would in fact open up a much broader initiative to restructure the electric power sector and increase the role of competitive generation suppliers.

In fact the proposals for PUHCA reform stimulated various interest groups to push for other reforms as well. Of particular importance were the efforts by independent power producers, municipal utilities, and industrial customers to obtain changes in the Federal Power Act that would expand FERC's authority to order wheeling service upon request by a wholesale or retail customer. Independent power interests, in particular, argued that they could not compete fairly with utilities in the wholesale market without access to transmission facilities made available based on reasonable terms and conditions. Thus, both the removal of regulatory barriers to ownership of IPPs and the increased availability of transmission service soon became linked together as being important components of policies to expand competitive wholesale market opportunities.

When the Energy Policy Act of 1992 was finally passed by the Congress in October 1992[51] it included changes in the Public Utility Holding Company Act and the Federal Power Act that

[51]P.L. 102-486, Title VII, October 24, 1992.

removed PUHCA's barriers to utilities and non-utilities having ownership interests in independent power producers, removed PUHCA's restrictions on U.S. utilities owning electric utility assets in other countries, and expanded FERC's authority to order utilities to provide wheeling service to support *wholesale* power transactions.

It is important to understand that EPAct92 is built around the traditional model of a regulated monopoly distribution company that has the exclusive right to serve retail customers within its franchise area. The utility in turn retains an obligation to serve all of these customers economically and reliably at prices regulated by a state commission. However, EPAct92 recognizes explicitly the potential benefits of encouraging utilities to meet this obligation to serve by considering all generation supply options, including purchases from competing third-party suppliers of generation services pursuant to incentive contracts rather than cost of service regulation. It recognizes further that efforts to create a competitive wholesale market in which utilities would have the opportunity to shop to meet the needs of their retail customers, and where competing generation suppliers could compete fairly to supply these needs, would accrue to the benefit of consumers.

To support the realization of this model of the utility sector, EPAct92 creates a new class of electricity generators called "Exempt Wholesale Generators" (EWG) whose owners and operators are exempt from the provisions of PUHCA that had created significant barriers to utility and non-utility entry into the IPP business. An EWG is defined as an entity engaged directly or indirectly through one or more affiliates exclusively in the business of owning or operating facilities engaged exclusively in producing electricity for sale at wholesale .[52]

EPAct92 also amended the Federal Power Act to expand greatly FERC's authority to order utilities to provide transmission (wheeling) service to support wholesale power transactions.[53] Buyers and sellers are now free to petition FERC to order transmitting utilities to provide wheeling service, even if meeting such requests requires the transmitting utility to expand its facilities. FERC in turn is to establish pricing regulations that promote the efficient generation and transmission of

[52]P.L. 102-486, Section 711.

[53]P.L. 102-486, Section 721.

electricity and that allow utilities to recover the full economic cost of the transmission service provided. In response to utility concerns about *retail wheeling*, EPAct92 includes a specific provision that limits FERC's authority to order wheeling to support wholesale power transactions only, thus making it clear that FERC has no authority to order a utility to wheel power to a retail customer.

The initial implementation of EPAct 1992 coincided with the transfer of executive branch power to the new Clinton Administration and its subsequent appointment of four new FERC commissioners. The new Commission has made a concerted effort to implement the pro-competitive provisions of EPAct92 quickly. On the EWG front, the Commission issued regulations governing certification and regulatory requirements for EWGs that make it easy for such entities to obtain the necessary certifications and to be subject to minimal regulatory reporting requirements. Ironically, however, the EWG provisions of EPAct92 have had relatively little impact so far on entry into and expansion of the independent generating sector. This reflects several factors. First, there is substantial excess generating capacity in many parts of the U.S., so that there has been little demand so far for new generating facilities that might be supplied by EWGs. Second, EPAct92 did not repeal PURPA's requirements for utilities to purchase from QFs, so that QFs continue to have a slight advantage. Third, many states still do not have planning and procurement regulations that explicitly require utilities to take all potential sources into account when they make long term generation supply decisions. Nevertheless, a number of QFs under construction have changed their status to EWGs and new suppliers no longer are forced to structure projects so that they meet PURPA's QF criteria in order to avoid PUHCA regulatory problems. As capacity needs emerge once again and state generation procurement policies adapt to the new vision of procurement in a competitive wholesale market, opportunities for EWGs should grow.

EPAct92 did have a very major impact of the participation of U.S. utility holding companies in the development of independent power facilities in other countries and in the privatization of electric utilities around the world. In just two years a significant number of U.S. utilities have invested significant funds in foreign utility ventures.

Probably the most important domestic impacts of EPAct92 to date have been associated with

FERC's efforts to use EPAct92 to expand transmission access opportunities for wholesale buyers and sellers. Among the most important policies that FERC has adopted are:

1. FERC has required utilities to publish detailed information about the availability of transmission capacity on their systems and related operating characteristics of their bulk power facilities.[54]

2. FERC has expanded the range of transmission services that utilities must be prepared to offer from simply point to point service to a full range of services that are "comparable" to the services that a vertically integrate utility provides to itself. It has also required utilities to include comparable service provisions in "voluntary" transmission service filings even when these filings are not responses to wheeling orders by the Commission under Section 211 of the Federal Power Act. Precisely what "comparability of service" means in practice is still evolving.[55]

3. FERC has allowed wholesale customers to file for "generic" tariffed transmission service even in the absence of a specific buyer and a specific seller.

4. FERC recently made it clear that its approval of market-based pricing applications and merger applications by vertically integrated utilities will be contingent on their filing open access transmission tariffs with comparable service provisions. Thus, FERC will no longer go through the charade of making a finding that specific market power concerns necessitate

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[54]Federal Energy Regulatory Commission, *Proposed New Reporting Requirements Implementing Section 213(b) of the FPA*, April 15, 1993.

[55]NARUC Bulletin No. 22-94, May 30, 1994, page 6 (re AEP and Florida Power & Light Company).

an open access filing.[56]

5. FERC has encouraged the formation of regional transmission groups (RTG) to deal with transmission planning, operations, and pricing issues on a comprehensive regional basis.[57]

While FERC has made significant progress on the transmission *access* front, it has made little progress on the transmission and ancillary services *pricing* front. This is unfortunate. Appropriate pricing has important implications for the location of new generating facilities and the use of existing facilities. There seems to be broad recognition that pricing reforms are desirable, but the Commission and its staff has shown little interest in taking a pro-active stance on transmission pricing. Moreover, the sharp distinction that the Commission has drawn between the "transmission function" and the "generation function" fails to recognize important complementarities between generation and transmission in the provision of a full range of efficient network services. These include dispatching, voltage and frequency control, load following, spinning reserves, settlements of differences between contracts and actual flows, backup services, etc. These services must be provided in an efficient wholesale market. The services must be defined, measured, and priced properly and credibly.[58] These issues are especially important in the U.S. where many transmission owners operate portions of a synchronized AC system in which property rights are poorly defined and associated externality and free riding problems are rampant. FERC would like to see these

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[56]*The Energy Daily*, August 11, 1994, page 1 (re an application for market based pricing by Heartland Energy Services an affiliate of Wisconsin Power & Light Company, Docket Nos. ER94-108, ER94-475) *Electric Utility Week*, August 1, 1994, page 11 (re proposed merger between Central & South West and El Paso Electric, Draft Order in Dockets EC94-7 and ER-898).

[57]Federal Energy Regulatory Commission, *Policy Statement Regarding Regional Transmission Groups*. July 30, 1993.

[58]FERC has recognized the existence of various "ancillary" services that are provided in conjunction with transmission service. However, it has provided little guidance for how to define or prices these services It rejected the one litigated utility application to charge for these services that it has been presented with since EPAct92. Federal Energy Regulatory Commission, Opinion No. 383 re Northern States Power Company. Docket Nos. ER90-349-000, ER90-406-000 and ER91-21-000.

issues handled by RTGs, but the development of RTGs has been slow and their progress in tackling issues related to pricing and ancillary services has been even slower. In 1993 FERC conducted an inquiry into its transmission pricing rules.[59] Numerous comments were submitted and two technical conference held in April 1994. A policy statement from FERC on transmission pricing based on this proceedung is likely to be issued in Fall 1994.

Despite these continuing problems, it is quite clear that unintegrated or integrated utilities which seek to meet their incremental generation needs by purchasing power from third-party suppliers can rely on competitive wholesale markets to make such transactions. Regulatory barriers to entry to the entry of independent power producers have largely been removed. When utilities go out for bids for capacity and energy they routinely receive large numbers of bids from many suppliers. Utility buyers and generation suppliers (and brokers) can get the transmission service they need to complete bilateral transactions between a particular generator and a particular distribution system customer. Developments in transmission access policies are likely to increase the ability of distribution system buyers to integrate efficiently multiple generating sources and to trade more actively in short term energy and capacity markets even if they do not operate their own transmission systems.

It is important to recognize, however, that the wholesale market that has evolved in the U.S. has some very special characteristics that are quite different from the markets that have been created in, for example, England and Wales. The wholesale market is built upon the backbone of vertically integrated utilities that operate over 140 control areas in cooperation with neighboring control areas which are part of the same synchronous systems. Despite extensive entry of QFs and IPPs in the last decade, they make up less than 10% of the energy produced and are largely non-dispatchable facilities that feed energy to their host utilities. The control areas bear the responsibilities for balancing loads and resources, maintaining frequency and voltage, providing spinning reserves, dispatching in response to transmission constraints, providing emergency support, and coordinatung operations with interconnected control areas. The costs of providing these services are borne almost

[59]Federal Energy Regulatory Commission, *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, June 30, 1993.

entirely by control areas and their franchise customers as well. Numerous bilateral and multilateral agreements and contracts are in place to affect this coordination and to make it possible to "move" power from sellers in one control area to buyers in another control area. Furthermore, the actual trade in the wholesale market is built upon a bilateral "wheeling model" which assumes that electricity actually moves from a specific generator to a specific load over a specific contract path defined over specific pieces of the transmission network and ignores the actual physical properties of a synchronized AC system. Most of the trades in the wholesale market continue to be associated with capacity that is temporarily excess to the needs of integrated utilities. New generation resources brought into the system are either owned by utilities or are supported by long term take and pay contracts. A "speculative entry" market for new generating facilities does not yet exist.

These wholesale market arrangements have worked and are working reasonably well to govern primarily transactions between interconnected vertically integrated control area operators who are not in competition with one another for the bulk of their revenues. It has been able to accommodate the entry of QFs relatively easily because most of them sell power to the control area operator where they are located and are non-dispatchable facilities. The efficacy of these rules depends on cooperation between control area operators, the relatively small number of buyers and sellers that participate in the market and the viability of the contractual fiction that power flows from a particular buyer to a particular seller along a particular contract path. The firm capacity/non-firm energy contract paradigm, the ability to monitor compliance with it, and extensive reciprocity in the provision of control area services between control area operators have been critical for allowing this market to function economically and reliability.

The rules that govern the operation of wholesale market in the U.S. have numerous imperfections, however. They have proven to be especially problematical to apply to small municipal utilities that now rely on competitive wholesale market purchases for a large fraction of their needs. Indeed, many of the disputes between control area operators and small municipal utilities embedded in their systems have actually been disputes arising from cream skimming, free riding, and the general problems associated with identifying and charging for all of the services that are actually provided by one or more suppliers connected to the network. Loop flow and other problems associated with the impacts of one supplier on other interconnected suppliers have been a continuing source of tension and dispute. These imperfections are likely to be increasingly costly as the wholesale market expands and retail wheeling is permitted unless more fundamental changes in industry structure, transmission and control area service pricing, and regulation of retail rates takes place.

RETAIL COMPETITION

The evolution of competition in the U.S. electric power sector has occurred within a model in which utilities continue to have the exclusive right to serve retail customers within specific geographic areas. That is, they have a monopoly to sell electricity to the public within a specific geographic area. In return for that right utilities have taken on an obligation to plan for their customers' needs and to make investments in generating facilities or enter into power contracts with third parties to meet these needs economically and reliably. Utility planning, resource acquisition and prices are also subject to state commission regulation. The provisions affecting electric utilities in EPAct92 (both those discussed above and numerous provisions affecting utility planning, energy conservation, and renewable energy) were based on this model as well.

Of course, the fact that utilities have a legal monopoly to sell electricity at retail does not mean that they face no competition. Large industrial customers can turn to cogeneration and self-generation and these options have been facilitated by PURPA and EPAct92. Municipalization is an option in many areas of the country, although we have seen relatively little municipalization activity in the U.S. since the 1950s, and much of the municipalization that took place earlier was stimulated by the availability of tax free financing to municipalities and preferential access to federal hydroelectric power. EPAct92 facilitates municipalization by making it easier for potential municipal utilities to obtain a wide range of transmission service that makes it possible for them to gain access to the wholesale generation market and to integrate diverse generation sources with only modest transmission expenses. Indeed, although the stimulus from the transmission access provisions in EPAct92 came largely from QF/IPP interests seeking to expand their market opportunities, most of FERC's activity on the transmission pricing front has been in response to requests from municipal utilities for expanded transmission services.[60]

The most important development in the public policy debate about the future of the U.S. electric power industry is associated with reforming the basic model of a monopoly supplier of electricity at retail responsible for "bundling" economical and reliable electricity supplies for its retail customers, relying on generation service supplied either from the utility's own facilities or under contract from third parties. Industrial customers in particular, as well as some IPP developers, have begun to promote a "retail wheeling" model in which the local utility would be required to unbundle transmission, distribution, and generation services and provide access to the wholesale market for retail customers who preferred to arrange for their own supplies in a competitive market. This alternative model is based on the same basic principles that have governed the restructuring of the electricity sector in England and Wales and the restructuring of the natural gas and telecommunications sectors in the U.S. Competitive services (e.g. generation) are to be separated from natural monopoly services (e.g. transmission and distribution) and these services made available and priced on an unbundled basis to retail customers. Retail wheeling customers are guaranteed access to the natural monopoly services at regulated rates so that they can shop among competing suppliers for the competitive services. As the utility's monopoly over the competitive services is removed so to is its obligation to plan for and supply its retail customers with these services at regulated rates.

The standard conceptualization of how retail customers would gain access to the competitive wholesale generation market reflects the current structure of the electric power industry and the bilateral contract/wheeling framework that has grown up around wholesale power transactions between electric utilities.[61] A retail customer would contract for generation service with one or more remote generating companies. The customer would then contract with its host utility and any

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[60]A variety of other economic factors have also increased incentives for municipalization. These factors are largely the same as those that have stimulated an interest in retail wheeling, a subject which I now turn to.

[61]Although proponents of retail wheeling have generally failed to specify a comprehensive model of how all of the pieces would fit together.

intervening utilities to provide transmission and control area services. The remote generating company would contract with its host control area operator for interconnection and dispatch services. The customer's host utility would provide backup service or partial requirements service to settle differences between what the customer takes from the system and what the third party generation suppliers it has contracted with deliver to the system. In essence, the retail customer is conceptualized in the same way as a municipal distribution company in terms of its relationship with the host utility and remote suppliers. This is not likely to be a sound framework in which to create an efficient electricity sector in which retail customers are responsible for making their own arrangements for electricity supplies in a competitive bulk power market. Major institutional reforms designed specifically to accommodate efficient competition need to be undertaken to support such a fully competitive system.

Why has there been so much pressure for expanding opportunities for retail wheeling in the last two years or so? Certainly all of the discussion of wholesale market competition surrounding EPAct92 created an environment in which the appropriate boundaries between competition and regulation would naturally be subject to ongoing debate. The experience in other countries, in particularly England and Wales, has been important as well. Its proponents argue that it has demonstrated that an electric power sector that departs from the traditional bundled franchise monopoly model and relies more on competition at wholesale and customer choice of suppliers at retail could work reasonably well if the appropriate industry structure and supporting market and regulatory institutions were in place and, more importantly, that it could help to promote efficiency improvements and lower prices.

However, the primary factor stimulating the interest in retail wheeling by large industrial customers is not credible evidence that there are huge short run or long run efficiency gains that can be achieved in the U.S. electric power sector. Many proponents of retail wheeling assert that very large improvements in efficiency will be achieved quickly, that rates could fall significantly if these efficiency gains are passed through as lower prices, and that utility investments and contractual commitments can be protected from significant financial losses. However, little if any credible evidence exists to support this "something for everyone" scenario. The evidence on efficiency improvements (but not price reductions) in the electricity sector in England and Wales since privatization and restructuring is certainly impressive. Unfortunately, it is not very relevant to the U.S. The performance attributes of the pre-1990 system in England and Wales were much poorer than they are today in the U.S. Indeed labor productivity in the U.S. electricity sector is still much better than in the UK. Moreover, labor costs account for only 12% of the price of electricity in the U.S. The average performance of U.S. generating plants today is certainly no worse than in England and Wales despite significant improvements in nuclear plant performance in England and Wales since 1990. Nor does the U.S. have the "coal problem" that was of concern to the Thatcher government. This is not to say that there is not room for efficiency improvements in the U.S. electricity sector. But rather that the U.S. sector starts off from a very different point on the productivity frontier than did the England and Wales system. Furthermore, regulatory and competitive constraints have induced U.S. utilities to undertake major cost reduction programs over the last few years. In my opinion, the major efficiencies associated with the introduction of retail wheeling will be associated with the choice, construction costs, and operating performance of *new* generating resources and the effectiveness of competition in undermining the politicization of utility resource procurement.

While the rhetoric of large short run efficiency improvements dominates the discussion of both wholesale and retail competition, the primary actual motivation for retail wheeling (and municipalization) today is the fact that in many parts of the U.S. the cost of generation services embedded in the bundled regulated rates that customers pay is significantly higher than the current price of generation services available in the wholesale market. In some areas of the country the difference between the embedded cost of generation and QF contracts and the wholesale price of generation service is 2 to 3 cents/kWh. The largest gaps are in California, the Northeast, and a few other areas scattered around the country. Table 2 displays estimates of the embedded cost of generation included in retail rates in different areas of the country. These costs vary widely by region. More importantly, in some areas of the country these embedded costs are significantly larger than the short run price of power in the wholesale market (2 to 3 cents/kWh) and/or the long run cost of power in the wholesale market (4 to 5 cents/kWh). The primary actual stimulus for retail wheeling today is the possibility that it may provide a mechanism for some customers to avoid paying for the full embedded cost of the generation capacity and power contract liability that utilities have on their books that have been permitted by regulators to be included in regulated electricity rates.

Why is the cost of generation service embedded in retail rates so much higher than the prevailing wholesale market price for generation services in some areas of the U.S.? It is because there is a large gap between the total costs utilities have incurred to supply electricity and the marginal cost of supplying electricity, at least in the short run. And it is the marginal cost which determines prices in the wholesale market. There are several reasons why this gap between total costs and marginal costs has emerged

1. The U.S. added nearly 100,000 Mw of nuclear capacity during the 1970s and 1980s. This capacity was built under the assumption that fossil fuel prices would continue to rise and to reach very high levels by the end of the century. These facilities cost much more than anticipated to build, cost much more to operate, and operate at lower levels of reliability than had been anticipated. The average total cost of nuclear facilities is frequently significantly higher than the current price of electricity in the wholesale market or the projected cost of new CCGT facilities. While the incremental cost of many nuclear facilities make it economical to continue operating them given the short run and long run costs of alternatives, some nuclear facilities are probably not economical to continue running even on an incremental cost basis.

2. There is substantial excess generating capacity in many parts of the U.S. as a consequence of slow demand growth and rapid expansion of QF capacity. The price of generation services in the wholesale market reflects this excess capacity situation and is often below the long run marginal cost of expansion. In areas like California, additional generating capacity does not appear to be needed until well into the next century.

3. Utilities in some areas of the country (especially California and the Northeast) where required to purchase too much QF capacity at too high a price under long term take and pay

contracts. Part of the problem results from bad luck in forecasting future capacity needs and future fossil fuel prices. However, the problem is also a consequence of the politicization of the resource acquisition process and the ability of QF interests to "capture" the regulatory process so as to increase the demand for and price of the power produced by these facilities. Environmentalists' interested in promoting cogeneration and renewable energy have also been an important force leading regulators to require utilities to base resource acquisition decisions on "social cost and benefit" criteria that lead to purchases of power that is more costly than could be sustained in a competitive market.

4. Utility energy conservation programs that provide subsidies to customers to use electricity more efficiently have both reduced the demand for electricity and have led to higher electricity prices.[62] A variety of other cross-subsidies are built into utility rate designs that would not be sustainable in a competitive market.[63]

5. Improvements in the efficiency of CCGT technology have significantly reduced the long run marginal cost of electricity produced using natural gas.

6. Probably the most important factor, however, is the abundant supply and very low price of natural gas available throughout the U.S. Fifteen years ago natural gas was viewed as a very scarce commodity whose price would rise significantly over time and which was too valuable to burn to produce electricity.[64] QF contracts designed by the California commission in the mid-1980s assumed that oil and natural gas prices would rise to the equivalent of $100/barrel by the end of the

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[62]Prices rise both to recover the utility's expenditures on energy conservation and because some of the most aggressive conservation programs are in areas of the country where the regulated price of electricity is far above its marginal cost.

[63]e.g. special rates for low income customers, geographic price averaging, grouping of customers with heterogenous load characteristics in the same rate class, etc.

[64]Indeed the Fuel Use Act of 1978 restricted the use of natural gas in utility boilers.

century. Instead of being too valuable to burn, natural gas has become the fuel of choice for both economic and environmental reasons in most parts of the country. Base-load electricity from CCGT technology can be produced for less than 4 cents/kWh in many parts of the country. QF contracts in California require utilities to pay as much as 11 cents/kWh in capacity and energy charges, however, and the average QF contract calls for payments above 7 cents/kWh.

It is of course politically attractive to portray the gap between wholesale market prices and utility generation costs as an indicator of utility operating inefficiency and that if customers could purchase in the wholesale market they could obtain low cost electricity that utilities are "blocking" from coming into the system. This is nonsense. The gap reflects the sunk costs of generating facility investment and QF contract commitments made in the past based on assumptions about economic conditions that have not be realized and which regulators have allowed utilities to include in their prices. On an operating cost basis utilities use the wholesale market to acquire as much energy and capacity as they can as long as the cost of those purchases is less than or equal to the utilities avoided costs. Utilities may not fully optimize on this dimension, but no study has found sufficient short run cost savings from more aggressive purchases from the short term and medium term energy markets to support large and rapid price reductions. If there are significant efficiency gains to be made from enhanced competition they likely to be associated largely with investments in new generating facilities and improvements in the availability of existing generating units.

The debate about retail wheeling is then largely a debate about who will pay for the sunk generation and QF contract costs that account for the gap between the embedded cost of generation supplied by utilities on a bundled basis and the price (marginal cost) of generation services on the wholesale market. This is generally referred to as the "stranded cost" problem. Utilities, not terribly enthusiastic about competition to begin with, are very much opposed to retail wheeling unless some credible mechanism can be found to provide for transition arrangements to pay for these stranded costs. Industrial customers and some of those who hope to make sales to them want the utilities' shareholders to pay for a large fraction of these costs. Representatives of small retail customer interests have opposed retail wheeling because they are concerned that the burden of stranded costs will be shifted to "captive customers" who will be unable to take advantage of retail competition opportunities.

It has also become a debate about how we conceptualize the role of private utilities in our society. Environmentalists have generally opposed retail wheeling because they have been able to use the monopoly franchise "utility as portfolio managers" model to provide subsidies for energy conservation and renewables that either could not be sustained in a competitive market or would have to be recovered from customers in different and more visible ways. More generally, private utilities in the U.S. have also traditionally taken on a quasi-public role in providing various services and supporting various social programs that we would not ordinarily find firms in competitive markets to find attractive. Some opponents of retail wheeling want to maintain the utility as an entity that has a "public service obligation fulfilled with private sector efficiency." Many proponents of retail wheeling see it as an opportunity to get utilities out of the "taxation by regulation business" and focusing their attention on producing electricity as a commodity as cheaply as they can.

The debate about retail wheeling is now taking place primarily at the state level, although FERC is likely to end up playing an important role in determining how it all turns out. Issues associated with expanding retail wheeling opportunities are being considered or have been considered by the public utility commissions in California, Massachusetts, New York, Connecticut, Michigan, Rhode Island, Wisconsin, and Illinois. Legislative initiatives have taken place or are underway in a number of other states including Nevada, New Mexico, and Ohio.

By and large the states have taken a fairly cautious approach to retail wheeling initiatives. The Connecticut Commission decided not to proceed with retail wheeling at this time arguing that it raised a number of complex issues which had to be resolved for it to work fairly and efficiently, that it would undermine utility initiatives affecting energy efficiency and the environment, that stranded cost issues were difficult to resolve, and that the primary efficiencies from retail wheeling would not emerge until new generation resources were needed.[65] The Commission decided that retail wheeling is not presently in the public interest. A task force created by the governor of Massachusetts, which included representatives from the public utility commission also identified a

[65]DPUC Investigation into Retail Electric Transmission Service, Docket No. 93-09-29, Draft Decision, August 5, 1994.

long set of issues associated with retail wheeling and concluded that it requires further study.[66] The Michigan Commission saw both potential costs and potential benefits associated with retail wheeling. It is putting in place a modest experiment to begin when new resources are required to help to resolve a long list of issues it identified.[67] The New York Commission recently began a study of retail wheeling and has indicated that it is approaching this issue with "extreme caution."[68]

The most extensive examination of the structure and regulation of the electric utility industry and the future role of competition is taking place presently in California. In April 1994, the California Commission issued a report (known as the "Blue Book") which laid out a set of major proposed structural and regulatory reforms for the electric power sector, including a phased in schedule for retail wheeling (called "direct access").[69] The Blue Book proposals include the introduction of Performance Based Regulation to replace traditional cost-of-service/rate of return regulation, unbundling of generation from transmission/distribution services, retail wheeling, and a Competition Transition Charge (CTC) to allow utilities to recover the "uneconomic" portion of their embedded generation costs and QF contract obligations through some type of unspecified surcharge on transmission, backup, or interconnection services. The process that has followed the issuance of the Blue Book has attracted participants from all over the country and has been quite contentious. While most participants have accepted the concept of "customer choice" through retail wheeling, there are wide differences in views about when and how it should be done, who should pay for stranded costs, and how these costs should be recovered. Major differences of opinion have also emerged regarding the institutional changes required to support a fully competitive electricity sector. Two of the utilities in California have argued that the creation of a regional pooling/grid operation mechanism similar to that in the England and Wales system is a necessary precondition to allowing

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[66]Massachusetts Division of Energy Resources, *Electric Utility Market Reform Task Force Report*, July 1994.

[67]Re Association of Businesses Advocating Tariff Equity, Michigan Public Service Commission, 1994.

[68]*Energy Daily*, Volume 22, No. 155, p. 1, 1994.

[69]*Proposed Policy Statement on Restructuring California's Electric Services Industry and Reforming Regulatory Policy*, April 20, 1994.

retail customers to shop for their own power in a competitive market. This position has been supported by the U.S. Department of Energy and some environmental groups. The other major utility and large customer groups have argued that retail wheeling should simply be superimposed on the existing bilateral contract/wheeling model that has emerged over time to support wholesale transactions between utilities. They argue that a regional pool is unnecessary, undesirable, and unattainable for supporting a competitive electricity sector with retail wheeling.

Those supporting a regional pool and associated wholesale market reforms have the better of the argument. Simply superimposing extensive retail competition on a system which was not designed to accommodate it may benefit some intermediaries who thrive on market disorganization and high transactions costs, but it will not lead to efficient competition. More fundamental structural reforms are required to create a system whose pieces work together to support competition taking into account the special physical and economic attributes of electric power networks.

The California Commission is likely to come to a decision by the end of the year and what it decides is likely to have important implications for the rest of the country.

Although FERC is precluded from requiring a utility to provide retail wheeling service, FERC is likely to play a significant role in resolving the debate about retail wheeling. This is the case because while FERC cannot order retail wheeling, it has asserted exclusive jurisdiction over the rates charged for "interstate" transmission service.[70] The availability of transmission and control area service at prices that support the efficient location of facilities, efficient use of transmission and distribution facilities, and efficient expansion of the transmission network is a critical component of an efficient competitive wholesale or retail electricity market. The ball here is in FERC's court, but FERC has so far been reluctant to play.

FERC has also started a rulemaking proceeding to determine rules for how it will deal with

[70]Notice of Proposed Rulemaking, *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Docket No. RM94-7-000, June 29, 1994.

recovery of stranded costs associated with both wholesale and retail service.[71] To the extent that states decide that they want to proceed with retail wheeling and provide for recovery of stranded costs, the natural place to recover the stranded cost-related charges would be as part of the transmission/distribution rate which customers cannot bypass since transmission and distribution service will continue to be regulated monopoly services under most competition models. However, FERC may have exclusive jurisdiction over these charges. The question now on the table is whether FERC will accommodate, encourage, or refuse to allow such charges in transmission rates. Precisely how this jurisdictional quagmire is handled can have important implications for the direction of industry restructuring and the expansion of opportunities for competition.

ISSUES ON THE HORIZON

So far, the expansion of competitive opportunities in the U.S. electricity sector has proceeded "incrementally" on top of an existing institutional structure composed primarily of fully vertically integrated utilities having monopoly retail service franchise areas and subject to cost of service regulation. Competition to date has largely been "on the margin" and virtually all existing generating capacity is either owned by utilities and paid for via cost of service regulation formulas or supported by long term contracts whose costs in turn are passed through to franchise monopoly customers. These institutions were not really designed to support either a fully competitive wholesale market or a fully competitive retail wheeling market. All of the discussion of wholesale and retail competition has naturally led to suggestions that the entire industry and regulatory framework be restructured so that all of the components work together well to support efficient competition where competition can be relied upon and to promote efficient and equitable supplies of services that are not conducive to being supplied efficiently by a competitive market and that will continue to be supplied by regulated monopolies. The primary issues that are now beginning to be discussed more seriously as a consequence of the interest in expanding competitive opportunities are the following:

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[71]Stranded costs associated with wholesale service are not really a big issue for most utilities. However, the Federal Appeals Court for the District of Columbia has expressed skepticism about the legality of adding a stranded cost or transition charge to transmission service charges. See *Cajun Electric Power Cooperative Inc. v. FERC*, No. 92-1461, July 12, 1994.

1. *Performance Based Regulation*: There is now widespread support for reforming traditional cost of service/rate of return regulation and replacing it or supplementing it with some type of incentive or performance-based regulation (PBR) mechanisms such as the RPI-x+y mechanisms used to regulate AT&T's interstate telephone rates and to regulate the prices charged by the RECs in England and Wales. While designing good PBR mechanisms is more difficult than the recent popular discussion suggests,[72] it is a lot easier to apply these concepts to electricity when new generation requirements are to be purchased in a competitive wholesale market and when the technology of choice is CCGT technology rather than nuclear or large coal facilities. The introduction of PBR mechanisms is an important component of the restructuring program proposed in California. I expect PBR mechanisms to become a much more important component of the electricity sector regulatory framework in the U.S. over the next few years.

2. *Improving Wholesale Market Institutions*: There is also growing acceptance of the view that utilities will be required to purchase any future generation requirements to serve their franchise customers through some type of competitive procurement protocol. Furthermore, to enhance the efficiency of the wholesale market reforms in transmission access and pricing rules are likely to be required and barriers created by the balkanized ownership and control of the three interconnected AC systems in the U.S. resolved.

I expect to see a lot of pressure to create regional transmission entities and regional power pooling and dispatch protocols. These entities would be responsible for supporting an efficient competitive generation sector by providing non-discriminatory transmission access at prices that reflect the real costs of providing the services, rather than contractual fictions associated with the bilateral contract point to point wheeling model, purchasing necessary control area services to allow the regional grid to operate economically and reliably (and passing along the associated costs to the buyers and sellers using the transmission system), and providing for integrated dispatch, coordination, and backup services and billing arrangements to allow for the efficient and reliable use

[72]See Joskow and Schmalansee (1986).

of generating facilities. While all of the necessary relationships can, in theory, be created with a complex web of bilateral and multilateral contracts, a regional transmission and pooling entity could provide the necessary services more efficiently and with less litigation. It can also provide a more visible set of market prices that can be used to write hedging and contingent financial contracts. Finally, the creation of regional transmission and dispatch entities can solve self-dealing and discrimination concerns associated with the continued common ownership of transmission and distribution facilities, a subject to which I now turn.

3. *Separation of Generation from Transmission*: The vast bulk of the generating capacity operating in the U.S. today is owned by utilities which rely on the energy they produce internally to meet the needs of their franchise customers (i.e. through vertical integration). Given the relatively slow growth rate of electricity demand, the electricity sector will remain largely vertically integrated for many years even if *all* new generation is purchased from third parties. The common ownership of transmission and generation capacity creates the opportunity for utilities to favor their own facilities over those of competitors and to use control over transmission facilities to manipulate access from or into proximate utility service areas by competing buyers or sellers. Precisely how serious these problems are in the light of federal and state regulatory rules restricting such behavior is a matter of some dispute. However, there is growing pressure on regulators to consider requiring utilities to sell off some or all of their generating capacity to independent third parties to affect a clear separation between the operation of the transmission network and the competitive generation market. In addition, it is argued that such a separation would allow all generating capacity to be subject to a market test and market incentives, not just new generating capacity as is now the case. Some of the arguments for the separation are self-serving of course, advanced by entities that hope to acquire these assets and operate them for a profit. Moreover, separation of the nuclear facilities in this way may not be feasible because of their costs and risk attributes. And of course the market value of any generation that is sold off to third parties will depend on the kind of market and contractual arrangements that will determine the prices at which it can sell electricity. While nobody has yet put forward a comprehensive plan for separating generation from the existing IOU structure.

it is clear that this will be a subject of lively discussion in the near future.

4. *Use of the Regulated Monopoly to Pursue Social Goals*: It is widely recognized that the institution of regulated monopoly in the U.S. is used for redistributive purposes via an implicit process of "taxation by regulation."[73] In the electricity sector, the institution of regulated monopoly has facilitated subsidies for energy conservation, purchases of environmentally friendly but privately costly generating technologies, research and development activities, special rates for selected groups, and other behavior that would be difficult or impossible to sustain in a fully competitive market.[74] The interest in expanding competitive opportunities, in particular the proposals for retail wheeling, are stimulating discussions of whether utilities should continue to be used to finance and implement the social goals associated with these programs and to identify alternative mechanisms for achieving them that are more compatible with competition. One of the great ironies of the last year is that California, a state that has been at the forefront of using utilities and their ratepayers to finance a wide variety of energy efficiency, environmental, and social programs, was the first state to make a comprehensive proposal to foster competition through retail access which will surely undermine both the nature of these programs and the ethos that has led to them. As I discussed earlier, the debate about retail wheeling is, in part, a debate about what policymakers expect electricity suppliers to be doing. Is it to supply electricity as cheaply as possible, align prices with costs, and to sell as much as they can, as would suppliers of any other commodity in a competitive market? Or should utilities be responsible for using their regulated monopoly to help to design and finance programs to ameliorate market imperfections associated with decisions about the use of electricity, environmental externalities associated with the production of electricity, and other social goals? The answer to these questions imply very different paths for the structure of the electricity sector and the role of competition. Not surprisingly, these are questions that politicians would prefer not to address directly and which the California proposal ducks by assuming that it can have it both ways.

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[73]Posner 1971.

[74]Joskow 1993b.

5. *Stranded Costs*: As discussed above, a major issue that will continue to dominate the discussion of industry restructuring and competition will be the question of who pays for the sunk costs associated with the gap between the generation and QF contract costs utilities have included in their retail rates and the wholesale price of electricity. A comprehensive resolution to the technical issues associated with implementing PBR mechanisms, reforming wholesale market institutions, unbundling and retail wheeling will not be forthcoming unless utilities can be induced to cooperate in the industry restructuring and regulatory reforms that are on the table. They will not cooperate fully until the stranded cost issue is resolved.

CONCLUSIONS

It seems fairly clear that the U.S. electricity sector is on a trajectory of fundamental reform. Increased reliance on competition, at least at the wholesale level, will proceed apace. Reforms in traditional cost-of-service regulation and more reliance on PBR mechanisms will accelerate. The recent pressures to rethink the role of the utility in society, to expand competitive opportunities for retail customers, and to restructure the industry so that it is specifically designed to support competition, rather than being twisted to accommodate it, are likely to intensify. Precisely how quickly this discussion will lead to further changes in industry structure, regulation and the expansion of competitive opportunities at wholesale and retail is uncertain, but it is unlikely that the competitive genie will ever get put back into the bottle. Things have moved along faster in the last couple of years than most people thought possible and there is little doubt that competitive opportunities will expand and regulatory and structural changes will take place to support them. It is merely a question of time and how much pain and cost we are going to incur as we move from here to there.

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TABLE 1

AVERAGE PRICE OF ELECTRICITY
1992
(cents/Kwh)

Area	Residential	Industrial
U.S. Average	9.0	5.5
New England	11.1	8.1
New York	13.8	8.8
New Jersey	11.5	8.0
Illinois	11.8	6.1
Chicago	12.6	7.0
Michigan	8.4	6.1
Detroit	9.8	6.8
Indiana	6.9	4.3
South Atlantic	7.9	4.9
East S. Central	6.7	4.2
Arkansas	9.1	6.0
California	12.2	8.2
Oregon	5.1	3.7

TABLE 2

ESTIMATED AVERAGE EMBEDDED GENERATION COST
1992

Area	Average Embedded Cost of Generation cents/Kwh
U.S. Average	3.8 - 4.1
New England	6.8 - 7.1
New York	6.2 - 7.2
New Jersey	6.4 - 6.7
Illinois	4.2 - 4.5
Chicago	4.5 - 5.0
Michigan	4.6 - 4.9
Detroit	5.3 - 5.8
Indiana	3.0 - 3.5
South Atlantic	3.4 - 3.8
East S. Central	3.0 - 3.2
Arkansas	4.2 - 4.5
California	6.4 - 6.6
Oregon	2.5 - 2.8

NOTE: Does not include costs of QF contracts which have significant impacts on overall utility power costs in New England, New York, New Jersey, and California.

FIGURE #1

NON-UTILITY GENERATION

(Thousands of GHW)