STATE CORPORATION COMMISSION
STAFF REPORT
DEVELOPMENTS IN WHOLESALE ELECTRIC POWER MARKET
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Introduction

On July 31, 1996, the Staff filed its Report On the Restructuring of the Electric Industry (Staff 's Report) in response to the Commission's September 18, 1995 Order in Case No. PUE950089.[1] The Report attempted to define the restructuring issues, identify and analyze the potential effects upon Virginia, and provide the Commonwealth's leaders with a foundation to further address the current debate over restructuring the U.S. electric industry. The Report was an initial step to develop effective policy in response to a rapidly changing industry. Several recommendations described in the Staff's Report require further evaluation and analysis.[2]

By Order entered November 12, 1996,[3] in the same proceeding, the Commission directed each investor-owned electric utility and cooperative, having non-utility generation (NUG) affecting Virginia jurisdictional rates, to report on its efforts to renegotiate its NUG contracts. This Order also directed Staff to continue monitoring developments in the power market and electric industry. Specifically, Staff was "directed to monitor developments in the wholesale power market and evaluate wholesale competition and its impact and potential impact on Virginia's utilities". Following is the Staff's report of its monitoring and observations to date regarding the current wholesale market. This report is an extension of the Staff's Report of July 1996. Additional reports are anticipated as the industry continues to evolve. Staff welcomes any comments and solicits any additional literature or studies to assist its on-going investigation.

Overview

Electric utilities have bought and sold generation capacity and energy among themselves for years. Typical transactions include hourly and daily trades (formerly referred to as economy transactions), short-term trades on a daily and a weekly basis, and limited term and unit power trades on a long-term, bilateral contract basis. Electricity has traditionally been supplied by electric utilities, using their own generating facilities or purchases from other utilities; to municipalities, cooperatives, and government agencies on a bilateral contract basis.

EPAct

A period of stresses on the electric industry and passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA), encouraged generation suppliers to take advantage of the utilities' reluctance to build additional capacity in the 1980s. A class of non-utility generators (NUGs) called qualifying facilities (QFs) provided an increasing portion of new capacity. Non-utility power production was boosted again with passage of the Energy Policy Act of 1992 (EPAct), which created another type of entity, the exempt wholesale generator (EWG). EPAct amended the Public Utility Holding Company Act of 1935 (PUHCA) to permit NUGs whose sole business is owning generation facilities to sell electricity in the wholesale market. EWGs have the same exemption from PUHCA as QFs, but without the size and operating requirements imposed on QFs or the obligation of utilities to purchase the EWGs' output. More NUG capacity has been constructed since 1989 than traditional utility facilities, although much of the new NUG capacity is owned by non-regulated affiliates of electric utilities.

Additionally, EPAct addressed transmission access, creating significant implications for increased wholesale competition. Utilities can no longer deny NUGs access to the transmission lines needed to sell power to entities other than the local utility. Though utilities own the transmission lines, the FERC (Federal Energy Regulatory Commission) has the authority to order access to the transmission lines. Utilities are compensated for access at approved FERC rates.

Any eligible entity can request a utility to transmit power generated by another entity into or through the utility's transmission system. Under EPAct, the utility must agree to provide the requested service or provide a written explanation of non-provision. The explanation must include the proposed rates, charges, terms, and conditions under which it will honor the request. It must also include analysis of any constraints affecting the provision of transmission service.

An eligible entity may request the FERC to order a utility to provide transmission services. The FERC may set a time limit for parties to reach an agreement and may opt to hold a hearing. If no agreement is reached or the FERC disapproves the agreement, it may issue a final order prescribing the terms and conditions for the parties to follow. The FERC can issue a wheeling order if it is in the public interest and does not impair the reliability of the electric systems affected by the order, but cannot issue an order requiring retail wheeling. The FERC order must include rates allowing the transmitting utility to recover all costs associated with providing the service. These costs must be recovered from the entity receiving the wheeled power, not from the utility's existing customers.

The FERC issued a notice of proposed rulemaking (NOPR) on March 29, 1995, accelerating its investigation of the U.S. electric industry restructuring.[4] Many parties, including the Commission Staff, filed comments in August 1995 expressing concern, disagreement, or need for clarification of certain issues raised in the NOPR. Although expressing general support of the concept of increased competition in, and improved transmission access for, bulk transfers of electricity, many parties believed the proposed rules violated certain provisions of the Federal Power Act and fell short of protecting the needs of native load customers and intruded on the states' jurisdictional authority.

FERC Order # 888

The FERC issued its final order in that case, # 888, on April 24, 1996.[5] Generally, the proposals outlined in the NOPR were adopted, with the intent to reduce wholesale power rates by extending competition. Order 888 establishes open access and comparable service as guidelines for transmission owners to sell transmission services to wholesale bulk power traders. These principles are implemented through *pro forma* open access tariffs filed by each transmission owner. These tariffs insure uniform terms and conditions across transmission owners required to provide comparable interconnection services to other parties. Individual *pro forma* tariffs combine to create a specific set of tariffs establishing parameters for open, comparable, and nondiscriminatory access to transmission services.[6] *pro forma* tariffs were filed with the FERC on July 9, 1996.

The FERC also required each generation company that is affiliated with an affected transmission owner to purchase transmission and ancillary services from its affiliate under the same terms and conditions as other generation companies. Thus, generation companies affiliated with different transmission owners may need to renegotiate their coordination agreements and contracts applying to bilateral transactions and power pools. Some transmission companies may need to remove discriminatory pricing provisions from their agreements and contracts.[7]

FERC Order # 889 and OASIS

Also on April 24, 1996 the FERC issued Order 889 to further implement EPAct. This second order requires electric utilities to establish electronic systems, dubbed "OASIS",[8] to share information about available transmission capacity and transmission services. This system is intended to provide all traders with the same transmission data that is available to the transmission owners. The FERC also allowed transmission owners to aggregate and develop a joint OASIS for a larger, contiguous geographic area.[9] Order 889 not only describes the data to be included in OASIS, but also the standards and protocols for posting such information and the procedures that utilities must follow in response to requests for transmission service. This Order also defines strict standards of conduct mandating separation of utilities' wholesale power marketing activities from their transmission operation. Utility personnel involved with wholesale power marketing must obtain transmission data through OASIS, like all other competitors.

Phase I of the OASIS was implemented on January 3, 1997. Many OASIS sites are working and have passed the required tests. The tests, currently administered by the North American Electric Reliability Council (NERC) to determine compliance, include site response to 1) node availability; 2) ATC query; 3) TRANSTATUS query; 4) automated downloading using Power Navigator; and 5) automated downloading using Continental Power Exchange (CPEX).[10] Other sites have not yet passed all of the tests. Most failures are due to deviating from the standard telecommunication protocol causing incompatibility problems when automatically downloading or are due to the lack of data or information required. The FERC's Order for Rehearing, Order 888-A, addressed standard protocol more definitively and required additional design changes. These Phase IA adjustments should be complete in the fall of 1997. Phase II, to be implemented in January 1998, will attempt to be more flexible to accommodate various software and functions, will attempt to make the system more user-friendly, and will require posting requests for energy schedules.

The FERC also issued a Capacity Reservation Tariff (CRT) NOPR on April 24, 1996, proposing a single tariff where all power market participants would reserve firm rights to transfer power between designated points. A CRT would supposedly provide all customers equal flexibility in reserving and using transmission service. The FERC believed this would allow all participants to know how much transmission capacity is available and allow transmitting utilities to plan better for system upgrades and expansion. Customers would be required to identify their needs and commit to such needs through the reservation process. Following a swarm of comments received from numerous affected parties, the NOPR has become dormant.

On May 24, 1996, the Commission Staff filed a request for rehearing of Order 888. The Staff believes the FERC exceeded its statutory authority by requiring generic industry-wide unbundling, open access and comparability, and that the FERC's finding of industry-wide undue discrimination is unfounded. The FERC's assertion of jurisdiction over the rates, terms, and conditions of unbundled retail transmission services, over stranded costs related to retail wheeling and over stranded costs from retail-turned-wholesale customers is contrary to law. The Staff also believes the reservation and curtailment priorities of the *pro forma* tariff fail to protect native load customers who have borne a significant portion of the costs of the existing transmission system. Also, the FERC improperly interfered with state authority to determine the necessity for upgrades and construction of transmission facilities. The Staff was joined by 135 other parties who also filed comments and requests for a rehearing of Order 888 and/or Order 889.[11]

The FERC issued its Order on Rehearing of Order No. 888 on March 4, 1997. The supplemental Order, No. 888-A,[12] reaffirms the core elements and framework of its original Order, but offers "clarifications" to issues raised in the Petitions for Rehearing in May 1996. Two clarifications may be viewed as raising new issues: a) FERC's authority to order "indirect" retail transmission and b) its authority over stranded costs associated with annexation. The Commission Staff filed on May 1, 1997, a Petition for Review of the FERC Order 888 and Order 888-A, expressing the same concerns raised in our filing of May 1996. Other state commissions and the National Association of Regulatory Utility Commissioners (NARUC) also filed Petitions for Review on or before May 5, 1997. Issues requested for review by NARUC include 1) jurisdiction of unbundled retail transmission; 2) stranded costs from retail wheeling and from retail-turned-wholesale customers; 3) the "revenues lost" approach to recovery of retail stranded costs; and 4) treatment of FERC jurisdiction over stranded costs associated with municipal annexation.

FERC Order # 592 and Mergers

On December 18, 1996, the FERC issued its Order No. 592 stating its intentions regarding evaluation of utility mergers. Although Order 592 is a "Policy Statement," it only announces intentions. It is a document that merely "updates and clarifies the procedures, criteria, and policies" for determining whether utility mergers are consistent with Section 203 of the Federal Power Act.[13]

The FERC will limit its review of merger effects to evaluating rates, regulation, and competition. Issues regarding purchase price, evidence of coercion, and accounting treatment are no longer critical areas of review. However, the FERC does expect utility mergers to be consistent with the Energy Policy Act and its own open-access transmission rule, Order No. 888.

Since 1994, there have been 22 utility mergers announced within the U.S.. Activity includes friendly and hostile mergers among electric utilities, between electric and gas utilities, and between large marketers and utilities (electric and gas). Most recently, Allegheny Power System Inc. agreed to purchase Duquesne Light Company and LG&E Energy announced its purchase of KU Energy. To date, four of the proposed acquisitions have failed or been denied, the most recent being between Wisconsin Energy Corp. and Northern States Power Company. FERC Commissioner William Massey said the most recent decision reinforces the Commission's policy to disallow any electric utility merger that will create an entity capable of dominating the generation power market.[14]

Market Development

The wholesale power market grew substantially as a result of the passage of PURPA of 1978. Additionally, the Energy Policy Act of 1992, with its sweeping changes, introduced a dramatic evolution of the market. The competitive forces that now exist due to the EPAct and the mandate of open access by FERC have introduced and will continue to introduce radical changes to the structure of the wholesale power market.

By one estimate, in 1995, sales in the wholesale power market in the broadest sense reached a level of 1,664,000 gigawatt-hours (GWh).[15] In terms of kilowatt-hours (kWhs) sold, the wholesale power market was just over half of the size of the retail market for electric power for that year. While data for 1996 is not yet available, it appears reasonable to assume that the size of the wholesale market will grow as competition increases and as the structure of the market develops.

OTC

An over-the-counter[16] (OTC) wholesale power market has existed for as long as utilities have been interconnected and able to conduct power transactions between themselves; yet any over-the-counter market such as this may exhibit various degrees of market development and liquidity. It is the level of these characteristics that, in large part, determine whether a given market achieves efficiency, and, since

1992, both market development and liquidity within the wholesale power market have increased dramatically.

Liquidity

Liquidity[17] is a crucial element of any well functioning market. Although liquidity was building in the wholesale power market in the early years of this decade, the level of liquidity in the market has risen substantially following the implementation of FERC Order 888. The most prominently mentioned indication of increasing liquidity is the explosive growth of sales by power marketers. Total sales by power marketers in 1996 exceeded 229,000 GWh compared to approximately 26,500 GWh in 1995. Viewed on a quarterly basis, these sales grew at a compound rate of 66.7% from the first quarter of 1995 through the fourth quarter of 1996.[18] Recent reports indicate that this amazing growth continued during the first quarter of this year.

Much of the volume of power marketers’ sales reflects sales between themselves and not increased generation or use of electric power. An Edison Electric Institute (EEI) study estimates that half of the sales by power marketers are to other marketers,[19] and in fact, a given contract for power may pass through the hands of several marketers before it actually goes to delivery. This is sometimes viewed as simply creating fictitious sales of no real significance; yet, these are not fictitious sales. These sales represent the activity of the “market” as it determines the true price of wholesale power, and often result from constantly changing market conditions for wholesale power. These sales also indicate the degree of liquidity in the market, and a liquid market ensures that a willing buyer can find a willing seller and negotiate a fair and accurate price. It also appears that power marketers are becoming the market intermediaries and thus, serving as market coordinators for wholesale sales and purchases.

Power marketer sales are dominated by a small number of firms (ENRON Power Marketing, Inc. accounted for 25.6% of power marketer sales in 1996, while sales by the top three marketers[20] comprised 45.4% of the total sales for 1996), but this domination appears to be lessening. According to the EEI study, the top five marketers had a 56.5% share of total power marketer sales in 1996 compared to 71% in 1995. The study also noted that 87 power marketers were actively trading in 1996, whereas only 37 were actively doing so the previous year. (It should be noted that by the end of 1996, FERC had certified 288 power marketers; as of the end of February 1997, the agency had certified a total of 303 marketers). Last year also saw a doubling to 54 of the number of utility affiliates involved in power marketing when compared to 1995.[21]

Several factors support the increased liquidity. The most important is the establishment of open access to the transmission grid. The varied generation mix of utilities and uncertain demand for power also create conditions for liquidity to develop as power marketers see an opportunity for profit, as does a highly interconnected transmission system that enables trading to take place on a wide scale.[22] In addition to these factors, the growth and development of trading hubs, pools and exchanges; the development of financial hedging instruments and price indexes; and state restructuring efforts have aided and will continue to support the growth of liquidity.

Trading Hubs

Rapid development of the wholesale power market began with the passage of the Energy Policy Act of 1992 and has continued through the implementation of FERC Order 888. The increased liquidity has also aided in market development. (In actuality, liquidity and market development each build upon the other.) This development has taken the form of trading hubs in the over-the-counter market; the development of price indexes and futures and options trading; the reorganization of pools; the increasing role of power marketers; and the formation of exchanges to trade power. To date, the wholesale market has developed to the extent that it might be said that there is a liquid market for daily and forward power purchases, but that there is not, as yet, a liquid market for capacity.

The backbone of the over-the-counter market is the set of trading hubs that exist within the nation's interconnected transmission grid. There are five major trading hubs within the eastern interconnection, and within the western interconnection there are two.[23] These hubs developed in areas where major transmission lines connect to join large subregions of the nation's transmission grid. They are not single points, but rather areas where major transmission lines intersect. There are also a number of other trading hubs within various subregions of the country, but the importance of a given trading hub is a function of the market activity, not simply the physical characteristics of the transmission system.

Two of the more well known trading hubs are those at Palo Verde, Arizona and the California-Oregon Border (COB). A brisk market developed at these hubs sooner than elsewhere in the country. Power trading concentrated at these hubs following the organization of the Western Systems Power Pool in the late 1980s. As trading grew, many participants saw the need for some measure of price discovery or "transparency" to facilitate optimal decision-making. This need resulted in the creation of the COB and Palo Verde electricity indices. Such indices benefit all market participants by providing price signals to aid in current and future decision-making and increasing the economic efficiency of the market.[24] The COB Index started in 1995. At the inception of the index, a group of 18 market participants, comprising power marketers, federal power agencies, and investor-owned utilities agreed to collaborate in providing trading data to calculate the index. These participants represented one-third of the generation in the region.[25]

Each participant reports its weighted average price for sales and megawatt hour volume for the previous day to Dow Jones & Co., Inc.,[26] each morning. Dow Jones then computes the index and disseminates it through sources such as Dow Jones-Telerate and The Wall Street Journal.

Shortly after the establishment of the COB Index, the Palo Verde Index was created. Nine investor-owned utilities and municipal power agencies agreed to report trading data similar to that reported for the COB Index to Dow Jones. This data is used to calculate the Palo Verde Index which is then disseminated through the Dow Jones financial reporting network.[27]

More recently, a price index based on trading at the Pennsylvania-Jersey-Maryland (PJM) interconnection has been developed which Dow Jones began reporting earlier this year. Given its significance as a major trading hub in the east, the PJM Index provides the price transparency similar to the COB and Palo Verde Indices. The PJM Interconnection was also considered at one time as the most likely delivery point for an east coast futures contract.

The trading at the PJM Interconnection differs from that at COB or Palo Verde in that PJM has now developed into a market exchange. On April 1, 1997, the PJM Interconnection, L.L.C.[28] contractually replaced the PJM Interconnection Association and thereby became "the nation's first bid-based energy market operating with a multi-state regional transmission tariff."[29] As of May 1, 1997, PJM members are able to purchase energy on the PJM spot market and sell the energy to load serving entities within the PJM control area. PJM members can also purchase energy from generation produced within the PJM control area and sell it to the PJM spot market. The bidding process for buying and selling energy in the PJM market is structured according to rules and regulations published by PJM. Real-time and historical posting of the hourly market clearing price on both OASIS and the PJM Internet home page allows transparency within the interconnection.

Market Exchanges

Markets are also evolving in other regions with the formation of other market exchanges, most notably the Western Power Exchange in California and the Mid-West Independent System Operator (ISO) proposal by American Electric Power, and the establishment of pool- or system-wide transmission tariffs by a number of pools and combined holding company systems.

This evolution of market structure is not occurring without a great deal of general complexity and contention. Many issues, such as methods of congestion pricing, independence of ISOs, and the question of whether transmission tariffs meet the requirements of FERC Order 888, still must be resolved. Their ultimate resolution will have a substantial impact on the development of the overall wholesale power market. For example, regulatory issues are one factor in the decreasing likelihood that PJM will be the delivery point for the first east coast futures contract. It is difficult at this time, however, to assess the specific outcome or effect of these issues.

The Energy Policy Act has also spurred the formation of the Continental Power Exchange[30] (CPEX®) which began 24-hour a day operations in July 1995. CPEX differs from the exchanges mentioned above in that it is an independent organization and not affiliated with an existing power pool. Participants in CPEX are located across the U.S. and extend into Canada, and through the exchange, they can electronically buy and sell hour-ahead and four hour-ahead bulk power. With 60 participants, the exchange claims to be North America's largest wholesale marketplace for physical electricity purchases and sales.[31]

Aside from the Energy Policy Act, the genesis of CPEX was the idea to make the next-hour power market more efficient. Most short-term transactions are accomplished by traders "working the phones," and CPEX sought to improve on this cumbersome and inefficient method by offering the ability to make on-line transactions possible through the use of sophisticated computer and telecommunications technology. A standard contract, called the National Interchange Agreement, is used to specify the terms and conditions of each transaction.

The number of participants in CPEX has grown from 30 trading companies in March 1996, to 60 today, and at least one CPEX transaction covered a distance of 1,500 miles (from Everett, Washington to La Crosse, Wisconsin). A CPEX official has stated that during a "good month" trading volume is in the hundreds of gigawatts and that annual trading volume has doubled each year that the exchange has been in existence.

Futures Trading

The development of market indices allowed the institution of futures trading in wholesale electric power under the auspices of the New York Mercantile Exchange (NYMEX). Currently futures contracts exist for power delivered at the COB or Palo Verde. NYMEX had hoped to offer a futures contract based on an east coast delivery point by early 1997, but as yet, no such contract exists. NYMEX, however, expects to seek federal approval for such a contract in the fall of this year. A NYMEX advisory committee has not decided upon an east coast delivery point, nor has it decided whether to offer one or two contracts. PJM appeared to be the early front-runner as the delivery point, but now a number of other hubs in the south and midwest are being considered.[32]

In a futures market,[33] buyers and sellers enter into contracts for the delivery of a commodity at a specific location and time and at a price that is set when the contract is made. The principal reason for this type of market is to allow hedging[34] against price fluctuations (i.e., risk). A futures market allows firms or investors interested in hedging to trade futures with investors interested in speculating. Many firms and investors view the futures market as a means to ensure that profits depend more on planning and design, rather than market volatility.[35]

Futures trading in the electric power industry is similar to that for other commodities. Standardized contracts are used to hedge against potential price risk, but the vast majority of contracts are settled by offsetting purchases or sales and not by physical delivery. A position in a futures contract that is not offset requires actual delivery or receipt of the amount of electricity specified in the contract.

Early experience in electricity futures trading shows that a much larger percentage of electricity contracts are not offset and therefore, go to physical delivery than do most other commodity contracts. For example, in December 1996, 3.8% of the COB contracts and 15.6% of the Palo Verde contracts went to delivery compared to 0.2% of the contracts for heating oil and 0.4% of those for natural gas.[36] The percentage of electricity futures that goes to physical delivery should be expected to decline as futures trading matures within the industry.

Futures trading of electric power does not alter the supply or demand pattern of the industry, nor does it affect the reliability of supply. Rather, it will provide a means of price discovery and a liquid trading forum. Energy risk management through hedging instruments should also allow market participants flexibility through such means as allowing customers to structure their power costs to meet their specific needs and by enabling providers to design products on behalf of their customers while minimizing risk to the firm. Other benefits include reduction of earnings volatility and improved budgeting and planning. The liquidity and transparency provided by futures exchanges also makes them ideal pricing benchmarks.[37]

Trading in electricity futures contracts, based on the delivery points at COB and Palo Verde, began on the NYMEX on March 29, 1996. The initial session exceeded expectations, although trading slowed somewhat after the initial interest. The greatest activity in the early trading was in the COB contract largely because of the history of cash market deals at the COB. By late May 1996, COB trading volume was averaging about 240 contracts daily, and the trading in the Palo Verde contract was reaching only about one quarter of these volumes. Most of this early activity in the electricity futures market came from independent power marketers.[38]

When trading of the COB and Palo Verde contracts began, a NYMEX official commented that NYMEX would not consider the contracts successful until trading of 500-1000 contracts a day occurred on a regular basis.[39] While trading of that volume in the two contracts did not occur in 1996, trading volume has increased substantially in 1997. Combined daily trading volume has averaged 720 contracts since February, with most of the increase coming from trading in the Palo Verde contract. This volume appears to meet the criterion considered by NYMEX to indicate a successful level of trading, but it is important to recognize that the trading in electricity futures has been growing slowly, if steadily.

Although the initial trading in electricity futures has been somewhat slow, there are several reasons to expect trading to increase substantially as time progresses. One significant factor that will lead to a greater volume of trading will be the development of a contract based on an eastern delivery point. The west coast contracts are not suitable for hedging activity in eastern markets, because the regions are, in effect, two separate, distinct markets. Once futures trading can begin for east coast market participants, trading volume may increase substantially.

Another factor is a continued expansion of the wholesale electric power market. Such expansion will provide the impetus for a larger volume of trading, as will increased sophistication of market participants, power marketers and utilities alike. Also, as more investor-owned utilities receive federal and state permission to trade in these markets, activity will likely increase.[40] Indeed, according to NYMEX Chairman Daniel Rappaport, electricity futures could be NYMEX's largest trading contract within five years, surpassing the current leader, crude oil.[41]

Options

Further advancement in risk management will come through the formation of liquid markets in options trading on the NYMEX and OTC. Options on the COB and Palo Verde electricity contracts began trading on NYMEX in late April 1996, about a month after trading in the futures contracts began. Options also trade over-the-counter. There is a subtle difference between exchange options and OTC options. Options trading on NYMEX are options to buy or sell the futures contracts (which, as noted above, do not usually result in physical delivery) traded on the exchange, whereas over-the-counter options are separately negotiated between a buyer and seller and are likely to be options to buy or sell through physical delivery.

Options offer an alternative means to hedge against price fluctuations (risk) compared to futures contracts. Hedging with futures contracts limits the profits of the firm or investor who is hedging, because with futures, a price is being "locked in." Options, in contrast, can be used to limit losses while still preserving the opportunity to make substantial profits.[42]

An options contract is an agreement between a buyer and a seller to grant the holder of the contract the right, but not the obligation, to buy or sell a commodity at a specified price on or before the day the contract expires.

There are two basic types of options contracts.[43] Call options give the contract buyer the right, but not the obligation to buy, a commodity at a set price called the strike price. The seller of the contract is call the option writer. The buyer may exercise the option and purchase the commodity at any time on or before the expiration date of the option. Put options grant the contract purchaser the right, but not the obligation, to sell a commodity to the option writer at the strike price on or before the contract expiration date. Buyers of both call and put options must pay a price, the option premium for the privilege of being able to buy or sell futures contracts or other items at a guaranteed price.

In one example reported two years ago in The Wall Street Journal, Boston Edison sought call options to buy approximately 250 MW of capacity between 1998 and 2004. The company took this course rather than commit to binding contracts in the forward market for capacity, given the uncertainty that exists within the electric power industry.[44]

It is conceivable that observers may question whether futures and options markets in electric power provide net benefits to society. An observer may feel that these markets are largely speculative and simply designed to provide investors an outlet to "play the market." Such a view, however, overlooks the basic nature of futures and options trading and ignores the positive role that these instruments play in fostering an efficient market. At the same time, it would be wrong to deny that there are not inherent risks in these markets.[45]

Futures and options markets separate the risk of changing electricity prices from the supply of electricity for those utilities and marketers who participate in the market. The risk of price changes is transferred to investors quite willing to assume such risks. Futures and options markets help reduce search costs and expand the flow of information on market opportunities. They may also create new market opportunities for electricity providers and users. In this sense, the markets tend to promote greater efficiency in the use of scarce resources. These developing markets may also tend to unify many local markets into a national or international forward market for electric power, overcoming geographic and institutional rigidities that tend to separate one market from another.

With the evolution of the wholesale power market since 1992, there is no question that a more competitive market exists now than before the passage of the Energy Policy Act. Given this, one might implicitly expect a shift of supply and demand within the market, in the direction of increased energy production and consumption. Although no such shift is discernible, to rely only on this condition as evidence to affirm the existence of a more competitive market is to miss the forest for the trees. So many factors affect the supply and demand in the wholesale power market that it is extremely difficult (particularly at this stage) to determine the causes of any shifts. It should be considered, as well, that the wholesale power market prior to the Energy Policy Act was competitive to a degree.

Competitive markets,[46] first and foremost, are desirable because they promote economic efficiency, i.e., the optimal allocation of resources, and this optimal allocation relies on efficient pricing. To the extent that wholesale markets have become more open, that more participants (whether power marketers or utilities) have entered the market, and that market institutions such as a futures market has developed, the degree of pricing efficiency has increased.

The degree of competition that exists within the wholesale power market and the extent to which it will develop, are open questions. Data at this time are scarce or, in many cases, not suitable to allow clear discernment of many trends. For example, it is next to impossible to say whether the activity of power marketers has increased the amount of wholesale power sales over what they would have been in their absence. In addition, it is an inherently different issue whether further developments on the federal level or within the market itself, will continue to foster a more competitive market or hinder it. It is entirely possible that the FERC may decide some issues, (merger policy, for example) in a manner that could hinder competition.

Thus, while the wholesale power market is more competitive in 1997, there is ample opportunity for the market to increase in its degree of competitiveness. If liquidity continues to increase, and the structure of the market continues to evolve, this is likely to be the case. Future issues that affect competitiveness must be addressed in their specific context.

Other Developments

Pools

The FERC’s Order 888 requires that any existing coordinating agreements among utility companies be modified to eliminate unduly discriminatory and preferential provisions to prevent discrimination against non-members. Among such agreements, the FERC included loose and tight power pools, public utility holding companies, and both short and long term, contractual and non-contractual, bilateral trading arrangements.

New pool agreements must establish open, non-discriminatory membership provisions that allow any market participant to join and have access to transmission facilities under the same open access tariffs as the previous members. One way of achieving comparable access, encouraged by the FERC for remedying undue discrimination, is to create Independent System Operators (ISOs). The FERC requires ISOs to follow an established set of guidelines to comply with its open access requirements.[47] Presently among Virginia's electric utilities, Delmarva Power & Light Company (Delmarva) is a member of the PJM (Pennsylvania-New Jersey-Maryland) pool while Kentucky Utilities (KU) and Appalachian Power Company (APCo) are among the members of the proposed Midwest ISO.

PJM

On February 28, 1997, the FERC issued an order accepting the December 31, 1996 filings for an amended PJM Interconnection Agreement and a system-wide PJM Open Access Tariff, Docket Nos. OA97-261-000 and ER97-1082-000. The filings were allowed to become effective on March 1, 1997, subject to refund and subject to the issuance of further orders.

The FERC noted that the PJM proposal presented two options concerning recovery of congestion costs. PECO Energy proposed recovering such costs from all pool users. Remaining members of the pool proposed recovering such costs from the parties transacting on the congested path. The FERC ordered PJM to implement the PECO proposal, but subject to refund and further order.

Congestion prices for network and point-to-point users are based on the difference in locational marginal costs between the appropriate injection and withdrawal busses. Locational market prices are used to calculate locational marginal prices (LMP), defined as the difference in locational prices between two network nodes. Buyers will be charged the LMP at the bus from which they withdraw power from the grid. Sellers will be paid the LMP at the bus in which they inject power into the grid. Locational marginal prices are calculated using two computer models. The State Estimator model calculates power flows at most system busses and the Locational Price Model calculates LMP at all load and generation busses. Transactions outside the PJM control area may cause loop flows within the PJM area resulting in congestion charges accrued to PJM transactions. In general, the parties to such transactions are not subject to PJM's tariffs and, most likely, will not incur congestion charges from PJM.

The pool will operate a spot market, which is actually a one-day forward market. They will announce an hourly unconstrained market clearing price (MCP), which is defined as the highest price increment of energy that would be dispatched on the unconstrained transmission network. The value of all sales to, and purchases from, the pool, will be calculated using the corresponding MCP. We note that parties trading in the pool have some flexibility to modify their transactions after the initial terms have been offered.[48] Spot market transactions will be used to forecast next-day congestion charges, and will be announced to allow users to modify their choices accordingly.

Customers are responsible to pay congestion charges through one of the available options. Firm transmission customers may buy Firm Transmission Rights (FTR) to avoid congestion charges. FTR will be traded in a secondary market. Non-firm transmission customers can use the forecasted next-day congestion charges to decide whether to pay congestion charges or be curtailed to avoid the charges.

VA Power Transmission Alliance

In June 1996, Virginia Power, Allegheny Power, Centerior Energy Corp., and Ohio Edison announced the formation of an alliance for coordinating the management of their transmission networks.[49] In this respect, the proposed alliance does some of the functions that would be done by an ISO, but the utilities retain control of their own transmission networks. In December 1996, the four utilities plus Southern Company asked the FERC for permission to conduct an experiment to test compensation methods included in the General Agreement on Parallel Paths (GAPP). The companies will use the GAPP principles to allocate among themselves revenues from transmission services.

Under the GAPP program, information on transmission paths will be electronically available to all participating utilities. This data will reveal the actual paths followed by network power flows during any transaction. Participants will charge the rates filed in their open access tariffs under Order 888, but the utilities on the redesigned contract paths will share their revenues with other utilities that carry at least five percent of the power flow.

In March 1997, the FERC approved the experiment for a two-year period, beginning April 2, 1997. The original utilities will be joined in the experiment by Cleveland Electric Illuminating Co., Toledo Edison, Pennsylvania Power Co., and Ontario Hydro. Participants must submit a report at the conclusion of the experiment, and host a conference in Washington, DC, to discuss the report, within six months after the experiment begins.

AEP Midwest ISO

A group of six transmission owning utilities announced a plan to establish a Midwest independent transmission system operator (M-ISO) on February 12, 1996. At the present time there are 25 transmission owners from 10 states voluntarily participating in the plan to further develop the ISO. One of the participating companies, Indianapolis Power and Light, withdrew its participation from the plan on May 12, 1997, expressing concerns about costs and benefits of the program and the creation of an ISO which is simultaneously truly independent and voluntary.

The M-ISO will allow existing control areas to retain local generation control and economic dispatch, and maintain system stability within their own boundaries. The M-ISO will be responsible for regional system security, which includes scheduling line outages, loading relief procedures, re-dispatch of generation, and, if needed, curtailment of transactions and load. The M-ISO would also provide regional planning for bulk transmission facilities, provide ancillary services, and maintain bulk transmission system reliability. The organizers still must resolve issues concerning cost shifting between utilities and the recovery of revenue requirements.

At the present time the M-ISO organizers plan to file a proposed plan with the FERC about mid-1997. The M-ISO expects to receive FERC approval this year, to begin limited operation in 1998, and to be fully operational in 2000.

VACAR

Utilities in Virginia, North Carolina, and South Carolina, voluntarily together monitor and evaluate regional issues. This working group, known as VACAR, is a subregion within the Southeastern Reliability Council (SERC) region of the NERC. It is Staff’s understanding that at the present time, the VACAR companies are entertaining discussion only, regarding future pool development.

Municipalities

Several Virginia municipal utilities, members of the Blue Ridge Power Agency (BRPA), a coalition of municipal utilities, have changed wholesale power suppliers from TVA or AEP to Cinergy Corp.. The BRPA negotiated with several other power providers to lower power costs to its members.

The City Council of Bristol, Virginia, signed a contract on February 12, 1997, with Cinergy Energy

Corp., of Indianapolis, Indiana, to purchase power for its Utilities Board, beginning January 1, 1998. Cinergy replaces TVA as the town's power supplier. By changing suppliers, the Bristol Virginia Utilities Board (BVUB) forecasts savings of $70 million over a seven year period, while maintaining the same quality of supply. The town's industrial customers will replace TVA's previously available interruptible rate, which caused considerable cost and inconvenience, with a firm rate at no additional cost. Residential customers are expected to save $10 per month.

TVA has indicated that Bristol's departure has caused them $50 million in stranded costs and that it will seek to recover this cost from the city. TVA has also offered to sell power to Bristol's industrial customers power at a rate 2 percent lower than the city's new rate. Cinergy has indicated that it stands ready to aid Bristol in any legal battles that may arise.

The city of Salem, Virginia, voted on April 28, 1997, to switch power suppliers from AEP to Cinergy. The city has estimated that it will save more than $17 million over a seven year period by changing suppliers.

Richlands, VA, another member of the BRPA, voted to buy electric power from Cinergy after its contract with AEP expires on June 30, 1998. The new contract with Cinergy includes BRPA members Bedford, Danville, Martinsville, and Salem. The municipal utilities involved expect to save about $117 million over the life of the contract. Only BRPA members Radford and Virginia Tech have not signed with Cinergy at the present time. Ultimately, Cinergy will provide 400 MWs to the BRPA.

Merchant Plants

Construction of merchant plants could ease the barriers to entry in the generation market and provide additional resources into the competitive side of the electric industry. Thus, a restructured utility industry should consider allowing for the building of merchant plants. Some older power plants have been positioned to operate as merchant plants. Similarly, some new power plants may be built to operate as merchant plants.

On September 16, 1996, Commonwealth Chesapeake Corp. (CCC) applied to the Virginia State Corporation Commission to build a 300 MW, oil-fired combustion turbine power plant in Accomack County, VA.[50] Without the CPCN, the developer cannot build the facility under the current regulatory regime and will likely be unable to find financing for the project. The SCC has yet to hear or decide the application.

Dominion Energy, Inc., a unit of Dominion Resources Inc., recently agreed to purchase the 1100 MW Kincaid coal-fired power plant in Kincaid, Illinois, from Commonwealth Edison Co. for about $186 million.[51] At the present time, Commonwealth Edison has a 15-year contract to buy all the electricity generated by the plant; but in later years the plant will be free to operate as a merchant plant and sell into the generation market.

Divestiture

Concerns about market power wielded by incumbent utilities in a deregulated market have prompted several actions by regulators. For example, the California PSC ordered Southern California Edison and PG&E to divest half of their generating plant assets leading to the release of 9600 MWs and 4000 MWs, respectively. These concerns have been intensified recently by proposed mergers in the electric utility industry. The FERC announced recently that it will not approve any electric utility mergers where the resulting utility could dominate the power generating market in its area.

For this reason, the FERC rejected the proposed merger of Wisconsin Energy Corporation and Northern States Power. The FERC suggested that the two utilities divest themselves of some generating assets to reduce the degree of market power that the resulting company could have over the region. There is speculation that the FERC may also reject the proposed merger of Centerior Energy Corp. and Ohio Edison Co. for similar reasons.

Corporate Unbundling

Some utilities have transferred various portions of their generation and power sales to marketers. This does not represent an increased level of industry activity but a reclassification of existing sales. In many cases, the marketer is a unit of the holding company, but in other cases it is an independent entity.

Oglethorpe Power, the nation’s largest generation and transmission rural electric cooperative, recently agreed to transfer all of its generation and load to marketers. Details are currently unavailable, but it appears it has released all its generator output and operation to marketers in return for provision of all its load requirements. Contracts have been signed with LG&E Power Marketing and Morgan Stanley to handle the long-term needs.

A unit of Allegheny Power System (APS), AYP Capital, purchased Duquesne Light Company’s fifty percent interest in the Fort Martin Power Station’s Unit No.1 for $170 million. AYP Capital expects to operate the unit as an exempt wholesale generator and sell the plant’s output at market rates. Since this announcement in 1996, Duquesne and APS have recently announced a proposal to merge.

Other

In a competitive environment the market should better link utility rates to marginal costs and send proper price signals to customers. Current programs involving real-time pricing (RTP) and advanced time-of-day rates (ATOD) offer methods to transition from a regulated environment to a competitive arena. Such programs are intended to send a more reflective price signal to customers, allowing better management of energy needs. It is believed these programs will evolve along with a more competitive market. What these programs may offer in the near term is the utility’s ability to lock-in a customer before the deregulated market becomes fully developed. Still, this could be a good deal for utilities and customers as it removes some uncertainty. Such programs deserve continued monitoring and review.

Another recent avenue involves the development of dispersed energy facilities (DEF).[52] This program allows for customers to provide self-generation and be less dependent on the market for their energy needs. Customers can construct, or arrange for construction, of on-site generation to supply electricity and/or steam to their own facilities. Numerous combinations of arrangements between the customer, the local utility and other power supply vendors create a flexible alternative to satisfy current and future energy requirements. These additional power sources may also contribute to the supply of available market generation. This concept merits further development and evaluation.

Technical Issues

Ancillary Services

Since the FERC issued its proposed rule on open access transmission in March 1996, ancillary services have been an important and controversial topic within the electric industry. Ancillary service costs comprise a substantial share of total bulk power costs. The FERC included six ancillary services in Order No. 888 that must be offered by transmission providers in their open access tariff: 1) scheduling, system control, and dispatch service; 2) reactive supply and voltage control from generation source service; 3) regulation and frequency response service; 4) energy imbalances service; 5) operating reserve-spinning reserve service; and 6) operating reserve-supplemental reserve service.[53] Loss compensations service may also be provided by transmission providers as an ancillary service to transmission customers.

Research done by the Oak Ridge National Laboratory using data from 12 U.S. utilities, estimated the cost of ancillary services to range from 0.15 cents to 0.68 cents/kWh, representing 5 to 25 percent of total bulk power costs, generation plus transmission costs. Their results also showed substantial differences across utilities in their estimates of individual services. Some of the most expensive services are the generation-related services (reserves and loss replacement). These services will most likely become competitive and their prices will likely decline during the next few years.[54]

Functional Unbundling

“Functional unbundling” refers to the requirement that all users be given equal access to information about transmission systems and to transmission services under comparable open access tariffs. It does not address the ability of utilities to use control over transmission, generation and bulk power transactions to manipulate transfer capability as discussed in the following section.

Antitrust agencies have argued that, at a minimum, operational unbundling is necessary to achieve FERC’s objective whereby control of the transmission network will be turned over to an ISO. The ISO should reduce the ability of vertically integrated transmission owners to discriminate against competing suppliers and buyers.

Uniformity

It is difficult to define and measure transmission capacity and to regulate its availability to third parties because power flows along multiple paths without regard to ownership or contract paths. FERC Order Nos. 888 and 889 require public utilities to provide information about and access to their transmission systems. This principle is intended to allow others to use those systems on the same terms as the utilities themselves.

Notwithstanding regulation, a utility may still have a competitively significant, although not unconstrained, ability to reduce the availability and reliability of transmission service, increasing the price of such service. A utility may limit the availability of transmission service to competitors in numerous ways. It may decide to change (or not change) the output levels of its generators, to leave a low-voltage line connected, or to limit supplies of reactive power in order to constrain the amount of transmission capacity available to competitors. It may also delay repairing or expanding transmission facilities, prolong maintenance outages or schedule maintenance outages during critical periods. In addition, it may engage in power sales that create loop flows that foreclose transmission service in another corridor. In addition to preventing specific sales by competitors, even occasional actions of these types may be used to undermine a competitor’s reliability as a supplier.[55] Therefore, utilities may be able to reduce the availability of transmission capacity for use by competitors that the FERC cannot effectively regulate.

Contract Path

Historically, when someone wanted to wheel power from one point on the system to another, they were charged by the “contract-path” method by the transmission owner. “The contract path may be a single, direct transmission path from the point of sale to the point of delivery. It might be the most direct, but it can easily be an alternate path that is less costly overall. Each time the contract path crosses a boundary at which transmission ownership changes, an additional transmission charge is incurred by the parties engaged in the transaction, increasing the total cost associated with the transaction. This is generally known as 'pancaking'."[56]

This approach is flawed because power does not actually flow just along the contract path. In addition, the increased 'pancaked' rates could inhibit competition. The contract-path method assumes that the full amount of the transaction flows through each system along the contract path.

Reliability

Another chief concern of deregulation to all parties is the continued reliable electric service enjoyed by the United States. The NERC has committed to assist the FERC and address reliability issues raised in the restructuring debate. The NERC is currently establishing security center functions within each subregion. For example, Virginia Power and Duke Power will be area security coordinators for the respective northern and southern portions of the SERC region. Initial rules and descriptions are to be ready to implement June 1, 1997, and will continue to evolve.

Interestingly, on September 16, 1996, most of Florida separated from SERC to establish the 10th Reliability Region of NERC called the Florida Reliability Coordinating Council (FRCC). Florida's geography as a peninsula creates some unique reliability issues, isolating it from the other members of SERC. The FRCC will better augment the reliability and adequacy of bulk power supply in Florida and in the NERC.

The West Coast blackouts that occurred on July 2 and August 10, 1996, have caused a great deal of concern about the potential negative impact of restructuring on system reliability. Over the years interstate transmission lines have been built so that utilities with excess power generation in one region can sell power to neighboring utilities for less than the purchasing utility could generate .

Today, dispatchers keep a 24-hour watch on all lines within a utility's transmission network to assure none are overloaded, and to take the necessary actions in the event a transmission line does fail. In most cases, they do not really know the maximum power-carrying capacity of each line because the capacity is dependent on weather conditions. Therefore, dispatchers generally use a given static rating which is the maximum amount of power a transmission line can carry under the worst ambient conditions.

As transmission-line conductors heat up from carrying increasing voltages, they sag closer to the ground and anything beneath the lines. The National Electric Safety Code specifies the minimum clearances that must be maintained at all times. Utility managers know that there are times when it is possible to push at least twice as much power down the line without violating clearance codes. Often, dispatchers will load a line to the maximum capacity before looking for alternatives.

There are, on occasion, days where the most adverse weather conditions do occur. On a hot summer day when there is no wind, the real rating falls below the static rating and sagging problems occur. This is apparently what happened on July 2, 1996, when the Bonneville Power Administration's 345-kV line between Wyoming and Idaho became so hot that it sagged through all the safety margins and touched a 15-ft high tree. Power was cut to 2 million customers in 14 states. Of an even larger magnitude was an outage on August 10, 1996, in Oregon. During this outage, which was also caused by conductors sagging toward trees, 4 million homes and businesses throughout the West were affected. Incidents like these have sparked the growing concern over transmission system reliability.

With open transmission access, transmission conductors may endure continuous high load conditions. Thermal limits are imposed on transmission line conductors for two reasons: 1) the transmission line loses strength because of overheating, reducing the expected life of the line, and 2) the transmission line expands and sags into the center of each span between the supporting towers. If the temperature is repeatedly too high, an overhead line can stretch and may cause its clearance from the ground to be less than required for safety reasons. This overheating is a gradual process, which means higher current flows can be safely allowed only for a limited time period.

Technology Advancement

Voltage is a measure of the electromotive force necessary to maintain a flow of electricity on a transmission line. Variations in electricity demand and failures on transmission or distribution lines can cause voltage fluctuations to occur. Constraints on the maximum voltage levels are set by the design of the transmission line and if the maximum is exceeded, short circuits, radio interference, and noise may occur.[57]

There are some remedies for constraints related to thermal limits and voltage-related limits, and there are other options to increase power transfer. Where thermal limits are concerned, it may be acceptable to allow increased temperatures and plan for a shorter life of the lines. It is sometimes possible to re-tension a span of conductor to increase ground clearances. Perhaps the most obvious, but most expensive method of alleviating the thermal constraints on a line is to replace the lines with larger conductors. However, this method requires consideration of tower structures and their design specifications.

The operating voltage for a voltage class of conductors may be increased without major configuration changes to the lines. However, it is also necessary to increase the voltages of the generators, and to makes some adjustments to the setting of the transformers, or possibly replace transformers in order to produce the new operating voltage. If this approach is employed, there must be coordination with the neighboring systems to prevent additional reactive power flows due to the increased power flows into the neighboring system.

Other remedies to voltage problems involve controlling reactive power flows. Capacitors and reactors generate and absorb reactive power flows, respectively. Placing these devices at strategic locations of the transmission system is a remedy to control reactive flows, thus increasing power transfers.

Some existing power flow control devices can be used to reduce the flow on lines with limited capacity, and/or to increase the flow on lines with ample capacity margins. These devices can be used to transfer more power without adding new transmission lines. Among the power flow control devices available are shunt capacitors and shunt reactors that can be used to control sending and receiving end voltages; series capacitors and series reactors that can change series reactance of lines (increase or decrease power flow); and phase angle regulators which allow for variable adjustments of power flow.

Power flow control devices are not without limitations and other considerations. They cannot be used to increase the thermal capacity of a line. Power flow devices redistribute power flows; they do not provide new transmission capacity. These devices have a limited application when parallel lines are operated near their thermal limits because redistribution of power flow could create overloads on parallel circuits. Power flow devices require complex controls and operating procedures and their coordination can be technically and operationally challenging. It must also be noted that most of these devices are suitable for solving specific voltage or flow problems caused by the growth of either load or generating capacity in a specific area and their installation can be expensive.

Overall control of network power flow could be many years away and is probably unrealistic. However, the use of power control devices may provide some network stability. The question exists of who will police the market. There are already signs that the new competitive pressures are eroding the traditional cooperation among regional controllers and utility dispatchers.

On August 26, 1996, a 345-kV transmission line carrying power to the load concentrations in New York tripped, forcing controllers to order load shedding at six different utilities. "This was the first time since 1977 that utilities in the New York Power Pool did not fully cooperate," says one official. Long Island Lighting Co. was forced to cut off service to 14,000 customers, while Consolidated Edison Co. claims to have done its part to ease the problem.[58]

Transactions in one state or region can affect the system capacity loading in areas far away. The blackouts raise questions of an ISO's ability in one state to keep the effects of a local disturbance from spreading elsewhere. Increases in the number and volume of power-trading transactions has exacerbated control problems.

Utilities cutting costs in preparation for deregulation may be compromising system reliability by such things as failure to provide on-line security monitoring, improper personnel training, lack of necessary maintenance to insure proper operations, and reduced tree trimming. The aforementioned cost-reduction measures have been said to have contributed to the severity of the West Coast outages. It is imperative that system reliability be at least maintained at its current level during and after the transition to competition. Some parties are concerned the current level of reliability will not be adequate with increasing movements of competitive power across regions.

David Freeman, who is appointed interim trustee of the California ISO, told the California Public Utilities Commission that competition of the electric power industry will likely improve reliability of the transmission system. "The reliability ought to be better because the buck will stop with the ISO. The ISO will have complete authority over the state's transmission system. In an emergency, the ISO would have full authority to make the critical operating decisions and override the market to preserve the viability of the transmission system. " [59]

Congestion

The most complex feature of market power analyses of the electric power industry is the need to take into account the unique characteristics of transmission. The transmission grid is not a switched network on which one can direct energy from a generator to a buyer along a particular path. Power flows along multiple paths without regard to ownership or contract paths. One must also take into account limits on feasible transfers of electric power. Attempting to define, measure, and regulate transmission capacity (more accurately, transfer capability) is difficult.[60]

There is no question that transmission access is necessary for a competitive wholesale electric market. When constraints and system congestion occur, not everyone can use the network in any way they want. While some have argued that transmission congestion is not a serious problem for the competitive market, there are signs to the contrary. There is a strong interest in acquiring tradable transmission rights or capacity reservations, which would suggest that there is a concern that congestion is or will be a problem. The resulting transmission congestion contracts provide a well-defined foundation for measuring and allocating transmission capacity.[61]

AEP Wyoming-Cloverdale Line

American Electric Power Company (AEP) released an independent study on May 1, 1997, confirming its need for a proposed 765,000-volt transmission line from Wyoming County, W Va. to Cloverdale, Virginia. According to the report, without the proposed line, the power system is at greater risk of breaking down and a side area, including Virginia's Roanoke Valley, could lose power temporarily. The line is necessary due to the growing demand for power. Presently the earliest the line could be built is 2002. Bernie Pasternack, AEP's Manager of Transmission Planning, says the system now operates under increased risk of failure and what he considers an unacceptable risk.

AEP continues to meet opposition from the Forest Service and environmentalists. Opponents to the line say it would spoil scenic views and disturb the environment in the Jefferson National Forest. The Company now says it will propose a new route for the line by late summer or early fall 1997.

Findings

One goal of most restructuring proposals is to enhance competition at the wholesale level. To accomplish this goal, regulated utilities will no longer have a monopoly on all aspects of providing energy to the end-use customer. Most proposals require regulated utilities to relinquish ownership or control, to some extent, of either generation or transmission facilities. Additionally, "writing down" stranded generating assets by allocating such costs to the transmission or distribution system, by charging customers exit fees, or via other mechanisms, is an item of many restructuring proposals. "All proposals to enhance competition at the wholesale level include opening access to transmission networks under comparable terms for all users".[62]

Recent industry conditions have been conducive to a transition to a more competitive wholesale market structure. The electric industry is enjoying a period of 1) surplus generation capacity or at least an apparent surplus; 2) relatively low and stable fuel prices; 3) manageable load growth rates; and 4) utility cost awareness and reductions. Such conditions provide available generation at attractive prices.

Arguably, the premise of the current debate is that a complete, rigorous, robust wholesale market exists. Large power marketers and investor owned utilities (IOU) generally support the notion that an increasingly active and liquid market exists. The number of FERC approved marketing applicants has grown to over 300 as of February 28, 1997. A high volume of trading among numerous participants creates and maintains a liquid market. Although IOUs have traditionally been the supplier of wholesale customers, many existing IOUs have expanded their trading departments to participate more actively in the wholesale market with the increasing number of power marketers and brokers.

Currently there is very little, if any, trading in the capacity market; the vast majority of transactions are for energy only. Typically, the trades are for short-term, hourly and daily transactions. These trades also utilize energy available beyond that needed to supply franchised, native load customers and fulfill existing bilateral contracts. However, an increasing number of trades are bid directly to the energy system, establishing the beginnings of a liquid market. The market clearing price reflects short-run incremental costs. This variable price is generally low in today's market because the majority of generation plants are existing depreciated facilities owned by utilities. The installed costs of these facilities are being recovered through rates paid by the utilities' customers within franchised territories.

While enjoying an apparent abundance of low-cost energy, there are concerns regarding future capacity additions. Many contracts for provision of wholesale power were arranged prior to the EPAct of 1992 and will remain in force for several years to come. Expiration of these long-term contracts will stimulate competitive bidding among various parties to replace the current supply of power. Full utilization of existing resources will eventually demand the development of enhanced or new facilities. Most players envision an active and growing number of participants bidding to be the supplier of choice.

Many believe the market will respond and add facilities when the market price reaches an appropriately sustained level to recoup the investment of installation. However, this implies the market price must reach a high enough level for a sustained period of time to attract investors in time to arrange for facility design, site preparation, permitting, and construction. When the current surplus capacity begins to deplete, the market is expected to enter a period of volatile, but higher prices. The situation could be aggravated by the period of time needed by the market to notice and respond. This encourages market prices to increase further and may likely cause power shortages and interruptions until new facilities can fulfill the need.

Some parties have suggested a method to minimize or prevent such a cycle is to require state certification for all suppliers, mandating a declaration of their available capacity plus reserve capacity, prior to selling in the market. All load serving entities would also be required to declare their expected demand. Coupled with market price signals, this more formal process could create a more stable structure to develop future sources and minimize the chances of load and supply imbalance. Care is needed to properly and singularly account for load and supply in multiple states.

Existing generating sources should provide adequate supply into the middle of the next decade. Generally, and not surprisingly, most unit additions are forecasted to be needed beyond any of the proposed periods to transition from a regulated industry to a fully competitive industry. The few expected unit additions within the next five years rely on advanced combustion turbine technology, fueled by natural gas. Most parties agree that there is an adequate supply of natural gas. However, some concern has been raised regarding the transmission infrastructure of the gas industry to deliver such increased volumes while maintaining current and continued low prices. Additionally, there is empirical evidence indicating an immediate need for additional existing transmission capacity.

Many issues require further development to assure a robust and reliable wholesale market. The delineation and associated pricing of ancillary services and transmission pricing, particularly with respect to the formation of ISOs, are among such issues. Although work is underway on these and other issues, many unanswered questions and contingencies remain. The electric industry must address all such concerns, prior to becoming a fully developed, competitive wholesale market.

The developing wholesale market has yet to be thoroughly tested. The ability of the market to consistently react to sudden or extended system changes because of catastrophic or extenuating circumstances is currently unknown. Only time and experience will determine the level of success during this new era.

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[1]Commonwealth of Virginia , ex rel. At the relation of the State Corporation Commission, Ex Parte: In the matter of reviewing and considering Commission policy regarding restructuring of and competition in the electric utility industry, Case No. PUE950089.

[2]Staff Report on the Restructuring of the Electric Industry, July 1996, Volume I, pp. 375-400. A list of the recommendations put forth by Staff appears in Appendix I.

[3]A copy of the Virginia State Corporation Commission's Order is attached as Appendix II.

[4]Notice of Proposed Rulemaking for Promoting Wholesale Competition Through Open Access and Non-Discriminatory Transmission Services by Public Utilities (Docket No. RM95-8-000) and Supplemental Notice for Rulemaking for Recovery Of Stranded Costs by Public Utilities and Transmitting Utilities, (Docket No. RM94-7-00).

[5]*In re Promoting Wholesale Competition Through Open Access and Non-*

Discriminatory Transmission Services by Public Utilities; Recovery Of Stranded Costs by Public Utilities and Transmitting Utilities, "Final Rule," Federal Energy Regulatory Commission Order No. 888, issued in Docket Nos. RM95-8-000 and RM94-7-001.

[6]*Summary of Key State Issues of FERC Orders 888 and 889*, The National Regulatory Research Institute, January 1997, p.2.

[7]Ibid., p.3.

[8]Open Access Same-time Information System

[9]*Summary of Key State Issues of FERC Orders 888 and 889*, The National Regulatory Research Institute, January 1997, p.3.

[10]Testing OASIS to determine compliance with Phase I as outlined in http://www.tsin.com :

> Test 1: Node Availability: 3 random logons in May to verify node is present & running.
> Test 2: ATC Query: Query 30 days of daily firm available transmission capacity offerings on one randomly selected path, verify reasonability of results.
> Test 3: TRANSTATUS Query: Identify number of transmission requests since 1/3/97, regardless of status as an indicator of the volume of business conducted on OASIS.
> Test 4: Automated Downloading: Test to see if the provider allows automated querying and download of data as specified in the Standards & Communications Protocols document. Test provided by Power Navigator and conducted by NERC.
> Test 5: Automated Downloading: Same as Test 4 except test conducted & results provided by Continental Power Exchange (CPEX), limited to providers to whom CPEX has access.

[11]*Staff Report on the Restructuring of the Electric Industry*, VA SCC, Case PUE950089, July 1996, p.115.

[12] *In re Promoting Wholesale Competition Through Open Access and Non-Discriminatory Transmission Services by Public Utilities; Recovery Of Stranded Costs by Public Utilities and Transmitting Utilities*, "Order on Rehearing," Federal Energy Regulatory Commission Order No. 888-A, issued in Docket Nos. RM95-8-001 and RM94-7-002.

[13]Marvin T. Griff, "What's New About the FERC's New Utility Merger Policy?", Public Utilities Fortnightly, February 1, 1997, p. 16.

[14]"FERC Commissioner Outlines Panel Policy On Utility Mergers," The Wall Street Journal, May 21, 1997.

[15] According to the Energy Information Administration, wholesale sales are measured best by combining the volumes reported on federal forms for purchases by utilities, purchases by non-utilities, and exchanges received.

[16]An over-the-counter transaction is conducted between a buyer and seller without the intermediation of an organized exchange.

[17]Liquidity is the quality or capability of any asset to be sold quickly with little risk of loss in value and possessing a relatively stable price over time (Definition from Peter S. Rose, Money and Capital Markets, 4th ed., Richard D. Irwin, Inc., 1992, p. D11.) and is a function of the number of participants and the amount of capital in a given market.

[18]Edison Electric Institute, Regulatory Research Services

[19]Dow Jones News Retrieval, "EEI/Power Marketer Sales -2: Market Less Concentrated," Dow Jones Telerate Energy Service, May 13, 1997,p 1.

[20]Duke/Louis Dreyfus LLC and LG&E Power Marketing, Inc. in addition to ENRON.

[21]Dow Jones News Retrieval (two citations), Mary O'Driscoll, "EEI Takes Slow, But Steady Approach to Restructuring," Energy Daily, May 14, 1997, pp. 1,4; "EEI/Power Marketer Sales -2: Market Less Concentrated," Dow Jones Telerate Energy Service, May 13, 1997, p.1; FERC Power Marketers: By Applicant, As of February 28, 1997, EEI's Regulatory Briefing Service, Edison Electric Institute, Regulatory Research Services.

[22]For a brief discussion of the growing liquidity in wholesale power markets, see Christopher Seiple, "Liquid Power Markets: A Rising Tide," Public Utilities Fortnightly, October 15, 1996, pp. 12-13.

[23]The major eastern trading hubs are: the Pennsylvania-Jersey-Maryland Interconnection, the Tennessee Valley Authority, and the control areas of Cinergy, Entergy, and Commonwealth Edison. In the west, the major trading hubs exist at the California-Oregon Border and at Palo Verde, Arizona.

[24]Bernard Speckman and Steven Schleimer, "A New Index Prices the Market," Public

Utilities Fortnightly, March 1, 1995, pp. 30-1, describes the history of the COB Index.

[25]Ibid.

[26]Dow Jones & Co., Inc. publishes The Wall Street Journal and other financial market news and data.

[27]A description of the trading at Palo Verde and the creation of the index can be found in Randy Dietrich, "Palo Verde Evolves as a Market Center in the Southwest, " Energy in the News, Fall 1995/Winter 1996, pp. 29-30.

[28]Limited liability company.

[29]PJM Press Release, April 3, 1997.

[30]The Continental Power Exchange, Inc. is an Atlanta-based corporation and is an independent, non-regulated subsidiary of Inter Coast Energy Company of Davenport, Iowa. InterCoast is a subsidiary of MidAmerican Energy.

[31]On the founding of CPEX, see John P. Stojka, "Automating the Next-Hour Energy Market," Public Utilities Fortnightly, November 1, 1994, pp. 22-25.

[32]Dow Jones News Retrieval, Jim Efstathiou, "Pricing Issues Sour Some on PJM-Based Electricity Contract," Dow Jones Telerate Energy Service, May 9, 1997, pp. 1-2.

[33]Futures trading is documented as far back as the Middle Ages. The first futures exchange in the U.S., the Chicago Board of Trade, was established in 1848.

[34]Hedging is the act of coordinated buying and selling of a commodity or financial claim in order to protect against the risk of future price fluctuation. Hedging, in effect, transfers the risk of unanticipated price changes from one investor to another (Rose, pp. 332-333).

[35]Rose, p. 332.

[36]"EEI/Power Marketer Sales -2: Market Less Concentrated," p.2; It is generally stated that, on average, of all contracts on futures exchanges only 1% result in physical delivery.

[37]Karen Klitzman, "Electricity Futures will Help the Industry Cope with Fundamental Changes to the Market," Energy in the News, Fall 1995/Winter 1996, p. 6, see also Peter K. Nance, "Potential Risk Management Applications of Electric Utilities: What Will Develop in the Electricity Markets," Energy in the News, Fall 1995/Winter 1996, pp. 10-13; Dow Jones News Retrieval, Preston D. Head, "Why Use Futures Contracts," Electrical World, January 1, 1996, pp. 3,6.

[38]Arthur Gottschalk, "Electricity Futures Charge Ahead," The Journal of Commerce, May 10, 1996.

[39]Ian Jones, "NYMEX Slams Home Electricity Contracts," Electric Utility Business and Finance, April 8, 1996, p. 5.

[40]Gottschalk, May 10, 1996.

[41]Suzanne McGee, "Electricity Futures Have Crackling Debut," The Wall Street Journal, April 1, 1996.

[42]This discussion is adapted from Rose, pp. 351-2.

[43]Options contracts traded on exchanges, like exchange traded futures contracts, are standardized contracts that control the quality of the items being traded, the permissible length of the contracts, and enhance the marketability of the options.

[44]Benjamin Holden, "Boston Edison Seeks Power Seeks Call Options For $40 Million of Electricity Each Year," The Wall Street Journal, May 16, 1995.

[45]This discussion is adapted from Rose, pp. 362-63.

[46]The term competitive markets is used here is its broadest sense, and this discussion is on a very general level. To do otherwise would introduce a level of detail beyond the scope of this report.

[47]Rose et al., p. 14 presents a list of these guidelines.

[48]This feature does have economic importance because it contributes to achieve equilibrium in competitive markets.

[49]There is a pending merger of Centerior & Ohio Edison.

[50]Application of Commonwealth Chesapeake Corporation *for Approval of Expenditures for New Generation Facilities Pursuant to VA Code § 56-234.3 and for a Certificate of Public Convenience and Necessity Pursuant to VA Code § 56-265.2, and for a Declaratory Order*, Case No. PUE960224.

[51]"Dominion Unit To Sell Power From Kincaid at Market Rates". Research Records Service, Daily Utility News, company News, 10/09/96. DRI is the holding company of

Virginia Power.

[52]Application of Virginia Electric and Power Co., Virginia Power SPC-I, Inc., Virginia Power SPC-II, Inc., and Chesapeake Paper Products Company *for Issuance of Certificates of Public Convenience and Necessity pursuant to Virginia Code § 56-265.2 and related regulatory approvals*, Case No. PUE950131.

[53]Eric Hirst and Brendan Kirby, " Costs for Electric-Power Ancillary Services," The Electricity Journal, December, 1996, p. 26-27.

[54]Ibid., p. 29.

[55]Mark W. Frankena, "FERC Must Fix Its Electric Utility Merger Policy," The Electricity Journal, October 1996, pp. 38-39.

[56]Michael A. Cannella, Ellis O. Disher, and Robert T Gagliardi, "Beyond the Contract Path: A Realistic Approach to Transmission Pricing," The Electricity Journal, November 1996, p.27.

[57]Arthur H. Fuldner, "Upgrading Transmission Capacity for Wholesale Electric Power Trade,"http://www.eia.doe.gov/fuelelectric.html.

[58]"Competition, deregulation: Is the US rushing into the dark?" Electrical World, October 1996, p.20.

[59]"California ISO Trustee: Competition Likely to Improve Reliability, Not Lessen It" Electric Utility Weekly. DOW Jones

[60]Frankena, p.32

[61]A transmission congestion contract is a financial instrument that entitles the holder to receive congestion payments for quantities of power at different locations.

[62]Dave Schoengold, The Unintended Impacts of Restructuring, The Electric Industry Restructuring Series for the National Council on Competition and the Electric Industry, October 1996, p. 9.