COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

THE MIDWEST POWER SUPPLY CRISIS OF JUNE 1998

CASE NO. PUE980335

STAFF REPORT

Prepared By:

Division of Economics and Finance

September 15, 1998

TABLE OF CONTENTS

INTRODUCTION

During the week of June 22, 1998, the price of wholesale electric power in the Midwestern United States rose to unprecedented and unimagined levels with the price of one megawatt-hour (MWh) of electricity reaching as high as $7,500 or $7.50 per kilowatt-hour (kWh). In response to the circumstances of that week, on June 26, 1998, Appalachian Power Company (APCO), citing a capacity shortage in the Midwestern United States, filed an application with the Commission seeking approval of Rider TEC (Temporary Emergency Curtailable Service). The Commission, in approving the tariff under Case No. PUE980335, directed Staff to investigate the capacity shortage situation cited by APCO. This report contains Staff's conclusions resulting from its investigation and examines the events and conditions underlying the spike in wholesale electricity prices. This report also contains an analysis of the behavior of the wholesale power market in order to understand why the market responded as it did during the week of June 22.

Several of the conclusions within this report must be regarded as tentative. Presently, the public utility commissions in Indiana and Ohio and the Federal Energy Regulatory Commission (FERC) are conducting investigations, and Congress intends to hold hearings into the matter as well. As these investigations will not be completed until the fall of this year, Staff intends to monitor their progress in the event that new information is forthcoming. Nevertheless, information available to date appears to indicate that the explanation of the events during the week of June 22 is reasonably straightforward.

Explanations offered in trade publications, industry documents, and FERC filings cite a confluence of several events that caused prices to spike. These events included significant capacity outages (both scheduled and forced), unusually hot and sustained weather that pushed demand to record levels, and financial collapse of several market participants. While it is possible that some participants acted maliciously or irresponsibly, such conduct, if it occurred, does not appear to have played a significant role in the extent to which the crisis reached.

The wholesale power market during June 22-26 exhibited a natural reaction to conditions of scarce supply; however, this observation may not be all-together comforting. The demand for electricity is instantaneous, and, given that electricity cannot be stored, this means that at times of very heavy demand and/or significant contingencies, there can be a very limited supply. During such times, utilities will bid up the price of that limited supply to whatever level is economically justifiable to them.

The episode in the Midwest also illustrated the nature of competitive power markets. Deregulated wholesale power markets have the potential to be very volatile due to the often stated, but apparently incompletely understood, uniqueness of electricity as a good or commodity. The default of several marketers during the June crisis also raises questions as to the number of potential competitors in wholesale markets. Small firms that lack significant financial resources simply may not be able to participate, because they may be incapable of coping with the potential risk. One would expect that market participants will learn from the recent experience and employ techniques to hedge against price volatility and that market mechanisms will evolve to mitigate price volatility; yet, it is unlikely that price volatility can or will be eliminated despite the pleas of some utilities and marketers. The economics of electricity supply and demand are arguably the most complex of any good available in the economy, in part, because electricity cannot be stored and, thus, there are no stocks to dampen price fluctuations.

The June crisis also has shown the vast difference in the economics of deregulated electric power markets and those under a regulated regime. Before deregulation, power companies could and would assist each other in times of crisis; but where there was once cooperation, there are now market forces. Many of the utilities that were relying on the wholesale market to meet their needs in June confronted these forces and found themselves in a position of having to buy very expensive power.

Finally, it has been noted by many whom have commented on the June crisis that the "market" worked. Such observations are correct. Power was available, albeit at a high cost, and apparently went to those purchasers who placed the highest value on it. Many interruptible industrial customers, who have since complained mightily, saw their power cut, but they simply suffered a risk that they should have known they were incurring. These results may not be comforting to legislators, regulators, and various market participants, but they must realize that competition does not mean that prices will always be low or that every consumer will always have as much electricity as they wish at a price they think fair.

The Midwest Power Supply Crisis
Of June 1998

Description of Events

Background

A significant potential for supply disruptions in the Midwestern United States existed as the summer began. In its 1998 Summer Assessment, the North American Electric Reliability Council (NERC) warned that "System operators and security coordinators will be seriously challenged to maintain the reliability of the North American bulk power supply system as a result of the potential capacity shortages in the Midwest and New England and the resultant transmission loadings." In the Midwest, in particular, as the summer began, over 11,400 MW of nuclear generating capacity was out-of-service.[1]

With respect to the area covering Indiana, Ohio, the lower peninsula of Michigan, Kentucky, and western Pennsylvania, the report noted that "the probability of exceeding the [capacity] margin available for contingencies . . . is the highest ever projected." The seriousness of this assessment is underscored by the fact that it assumed the availability of American Electric Power's (AEP) Cook 1 and 2 nuclear units, which were subsequently determined to be unavailable. NERC also warned that the simultaneous occurrence of heavy demand on system capacity and heavy transmission line loadings would exacerbate the risks to regional reliability.[2] (With respect to the proposed Wyoming-Cloverdale 765 kV transmission line in West Virginia

[1] North American Reliability Council (NERC), 1998 Summer Assessment, May 1998, p. 3; The following companies had nuclear capacity out-of-service: Ontario Hydro (4,300 MW), Illinois Power (Clinton unit-930MW), American Electric Power (Cook units 1 & 2-2060 MW), Commonwealth Edison (LaSalle units 1 & 2-2096 MW and Zion units 1& 2-2080 MW)

[2] NERC, 1998 Summer Assessment, p. 22,2; NERC is owned by ten regional reliability councils. The area described here is covered under the East Central Reliability Agreement (ECAR). The other council region most affected by the events in June was the Mid-America Interconnected Network (MAIN) which covers the area comprised of Illinois, the eastern portions of Missouri and Wisconsin, and most of the upper peninsula of Michigan.

and Virginia, NERC noted its risks to reliability within ECAR given line outage contingencies in eastern ECAR, but the lack of the proposed line was not a significant factor in the June crisis.)

Regarding the lower peninsula of Michigan in isolation from the rest of the region, NERC observed that should additional resources be needed beyond those secured from the southern U.S., Michigan would be competing for available resources with capacity deficient areas in Illinois and Wisconsin, as well as the Northeast.[3]

In Illinois, NERC recognized the capacity resource situation as being particularly critical. Commonwealth Edison began the summer with a capacity margin of only 9.4%, while Illinois Power projected a capacity margin (including firm purchases) of only 3.7%, "clearly making [the company] dependent on imports of nonfirm energy to carry it through peak demand conditions."[4]

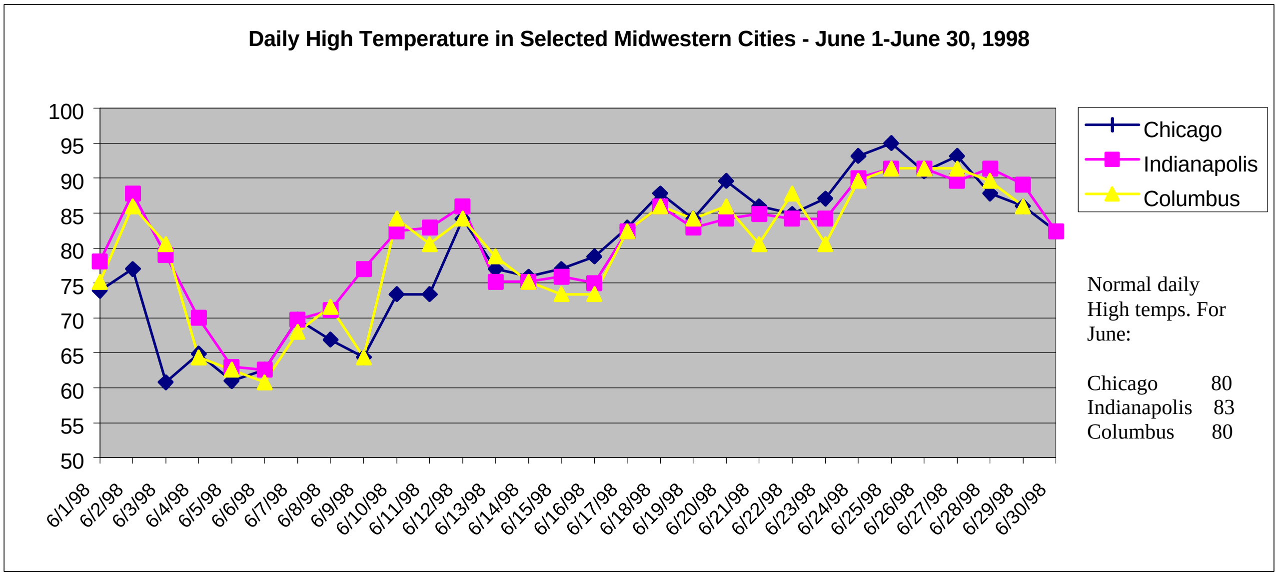
The Week of June 22

With the stage thus set, by the latter half of June, temperatures in the Midwest began rising above normal, and for the week of June 22, weather forecasters expected temperatures well above normal. It may be seen on the graph below that temperatures in the selected Midwestern cities, which were already slightly above normal, jumped approximately 6 to 9 degrees on June 24. It was precisely at this point that a series of events sent prices skyrocketing.

As temperatures and utilities' loads rose throughout the eastern half of the U.S., on Wednesday, June 24 a small power marketing firm, Federal Energy Sales, Inc., defaulted on agreements to provide power to several utilities and power marketing firms, including FirstEnergy Corp.[5] and Southern Indiana Gas and Electric Company. Federal Energy Sales's

[3] Reliability Assessment Subcommittee of NERC, 1998 Special Assessment of Michigan/Ontario, May 1998, p. B-6.
[4] Reliability Assessment Subcommittee of NERC, 1998 Special Assessment of MAIN/MAPP, May 1998, p. A-4.
[5] FirstEnergy Corp. is the holding company for ToledoEdison, PennPower, OhioEdison, and The Illuminating Company. FirstEnergy was hit twice by the Federal Energy default. That default caused the Power Company of America to default in its agreement with FirstEnergy. A similar situation occurred for SIGCORP.

default led directly to the default of The Power Company of America and, most notably City Water, Light and Power, the municipal utility of Springfield, Illinois.



Source: National Climatic Data Center

At the same time that Federal Energy was defaulting, utilities lost a substantial amount of generating capacity. American Electric Power (AEP) lost three units on June 24 providing 1,380 MWs of capacity on top of 1,198 MWs of generation that had been lost over the previous week and a half.[6] On Wednesday, prices for wholesale power rose to over $1,500 per MWh within ECAR. At least one utility, Illinois Power, declared a control area emergency.

The situation worsened Wednesday evening as a tornado damaged three 345 kV transmission lines at FirstEnergy's Davis-Besse substation and triggered a shutdown of the Davis-Besse nuclear unit (approx. 900 MW). The damage done here was doubly bad, because not only was additional capacity lost, but transmission import capability into the ECAR region was harmed.

[6] On June 24, AEP lost Amos 2 –reheat tube leak- (800 MW), Conesville 5 –tube leak- (375 MW), and Kammer 2 –tube leak- (205 MW). Previously, the Company's Muskingum River 5 unit –balanced generator- (580 MW) and Cardinal unit –tube leak- (590 MW) went out of service on June 22; the remaining capacity outages were partial losses. The totals do not include the Cook nuclear units (2060 MW) which were out of service before the heat wave.

By one account, as early as 9:00 on Thursday, June 25, "it became apparent that purchases in the wholesale market for the peak hours would be limited, or non-existent. Also, prices in the wholesale market during the mid-morning hours were approaching [the] all-time highs on Wednesday . . . ."[7] System loads across the Midwest approached or exceeded all-time peaks, all the while additional outages continued to occur.[8] Little help was available from outside the Midwest as a result of transmission constraints and the enormous scope of the heat wave, which was placing heavy demands on utilities to the south and east.[9] Once, again utilities across the region cut power to interruptible customers and urged other retail consumers to conserve. Prices soared. News and trade publications reported a documented high of $7,500 per MWh and a rumored high of $10,000 per MWh.

On Friday, June 26, the crisis eased. Temperatures moderated somewhat across the Midwest and along with transmission repairs, a net of 1,355 MWs of capacity returned to service in ECAR. (1670 MWs of AEP's capacity had returned to service.) Spot prices for power also eased on Friday, in part because of apparent resistance by many utilities to paying such high prices. Estimates vary, but prices seem to have declined to below $1,000 per MWh.

Although verification of wholesale prices is difficult due to the over-the-counter nature of most wholesale power trading, several utilities have indicated the prices at which they bought and sold power during June 24-June 26. Northern Indiana Public Service Company reported that

[7] Comments of Indianapolis Power and Light Company in Response to an Indiana Utility Regulatory Commission Inquiry Regarding Power Supply and Pricing During the Week of June 22, 1998, p.8.
[8] Between AEP, Northern Indiana Public Service Co., and Cinergy another 1500 MWs of capacity was lost on June 25; AEP lost Tanners Creek 4 –hole blow in windbox- (500 MW). All told, there were 9,619 MWs of capacity forced out-of-service in ECAR on June 25. On the previous day, the forced outage total was slightly higher, 10,096 MW. The forced outage total for both days includes the Cook nuclear units.
[9] On June 25, PJM declared a Maximum Generation Emergency and recalled approximately 5,300 MW, which was to be delivered to entities outside of PJM. PJM also declared a Maximum Generation Emergency on June 26.

it purchased power in a price range of $40-$5,300 per MWh. Wabash Valley Power Association paid $325-$5,000 for power over the period. Southern Indiana Gas and Electric Company was a net seller over a range of $35-$3,750. According to several accounts, Commonwealth Edison Company paid up to $6,000 per MWh.

Much of what unfolded over June 24-26 is readily understandable. A heat wave, severe in degree and extent, compounded by violent weather and forced outages created a severe power supply crisis. The basis of that crisis lay in the shortage of capacity with which the Midwest began the summer. NERC had projected capacity margins in both ECAR and MAIN at approximately 11.0%[10], and due to several of the nuclear unit outages, actual margins were less than the projected margins. The wholesale power market simply responded to a severe shortage that was precipitated over the critical days. In doing so, it revealed a great deal about the nature of competitive power markets.

[10] In terms of reserve margins, the NERC projections yielded a 12.8% margin for ECAR and MAIN combined. For the Eastern Interconnection, NERC projected a reserve margin of 18.4% for this summer.

Analysis of the Crisis and the Market Response

Overview

As one seeks to understand the price volatility that occurred in June within the wholesale power market, one cannot help but confront the observation that "This never happened before competition." Upon reflection, however, one realizes that the observation misses the point. The mechanisms of a competitive power market are so different to those of a regulated market that one cannot necessarily make the comparison.

The fact that the volatility observed in June had not occurred previously, does not mean that the underlying factors have not always been present. They have simply been handled in different ways. Before deregulation of wholesale markets, utilities confronting a contingency such as that in June did not bid for power on an open, competitive market. Rather, they strove to ensure that they had sufficient capacity built for such contingencies, in which case the expense would be recovered through embedded-cost rates, and they cooperated through shared-savings arrangements. Price risk was shared between companies or passed on to ratepayers. Now, however, utilities find themselves facing price risks that they never explicitly faced before and having to cope with this risk through various means of hedging.

First and foremost, the June power crisis must be understood as a phenomenon of supply and demand for a good that is characterized by instantaneous demand, yet cannot be stored. Demand for electricity approached an exhaustible level of supply, and the resultant price spike was exacerbated by trading related to the forward component of the wholesale market.

Market participants were shocked by the events during the week of June 22, but the episode revealed the potential volatility of competitive power markets and taught many lessons as to the risks of wholesale markets.

Basic Economic Concepts of Wholesale Power Markets

There are many complicating factors to an explanation of how wholesale power markets behaved in June. Many of these will be discussed below, but a basic understanding of the economics involved will be helpful before other factors are considered.

A well-functioning wholesale market must provide appropriate price signals to provide the incentive to construct new generation. Clearly, this means that as additional capacity becomes needed, prices for at least several hours during peak periods may rise to what appear to be very high levels. This is, at least in part, because before new investment is undertaken the prices must reflect the cost of both capacity and energy.

Consider, for example, a combustion turbine, at a cost of $300 kW with annual carrying costs of 20%, that is expected to operate for 438 hours annually (a capacity factor of 5%). This means that the fixed costs per hour of operation for one year would be:

(300*.20) / 438 = .1369 cents per kWh or $136.90 per MWh

Now assume that the capacity was only needed for, say 100 hours in a given year. In this case, the fixed costs per hour of operation for one year would be:

(300*.20) / 100 = .60 cents per kWh or $600 per MWh.

If we shorten the expected operating period to 50 hours, the cost rises to $1,200 per MWh. Certainly, this is a long way from $7,500 per MWh, but the pattern is obvious. To induce the construction of additional generation, the price of wholesale power must reach what seems to be very high levels for several hours a year, and thus, there should be no great surprise if prices rise to several hundred dollars per MWh or more.[11]

[11] In the wake of the June crisis, Illinova, the parent of Illinois Power Company, petitioned FERC to cap the price of emergency power at $200 per MWh.

The cost of generation that is embodied in prices is only one aspect of the price of wholesale power. There are two other factors that are likely to contribute to periodic spikes. This first factor is simply that when electricity is scarce, i.e., at times such as June when generating capacity approaches its maximum limit, consumers (or in the case of June, utilities and marketers) can bid whatever the value is to them to ensure that their power supply meets their needs. Leaving aside the issue of a utility's public service obligation (which is discussed below), utilities that paid high prices on June 24-26 did so because it was worth it to them, for whatever reasons, to do so.

The discussion in the previous paragraph brings us to the second factor. As power demands reach their peaks, there are fewer and fewer suppliers and less supply available. At such times, it is likely that producers and suppliers will have varying degrees of market power.[12] During the days of June 24 and 25, particularly the latter, this point was reached as a result of the outages, transmission constraints, and the severe weather over an extended period.

Irrespective of the preceding discussion, there seems to be a general impression that short-term wholesale prices should follow marginal costs, i.e., running costs or system lambda, but as the preceding discussion shows, this belief is hard to justify. Short-term firm prices, whether hourly, daily, or monthly, will implicitly include the availability of capacity, and using the June price spike as an example, this value has the potential to fluctuate wildly.

[12] This discussion should not be taken to mean that sellers can "gouge" buyers. Such terminology is based upon concepts of fairness that are beyond the ability of economics to determine.

Characteristics of the Wholesale Power Market

As the turmoil surrounding the events of late-June would seem to indicate, the development of the competitive wholesale power market is in its infancy, and it is something of an understatement to say that market participants are still learning about the dynamics of the market. The market is regional, with the regionality exacerbated by transmission constraints, which may or may not be present at a given time due to the physics of power flows. The presence of transmission constraints mean, in effect that the number and/or size of sub-regional markets may change based on the degree and location of transmission congestion.

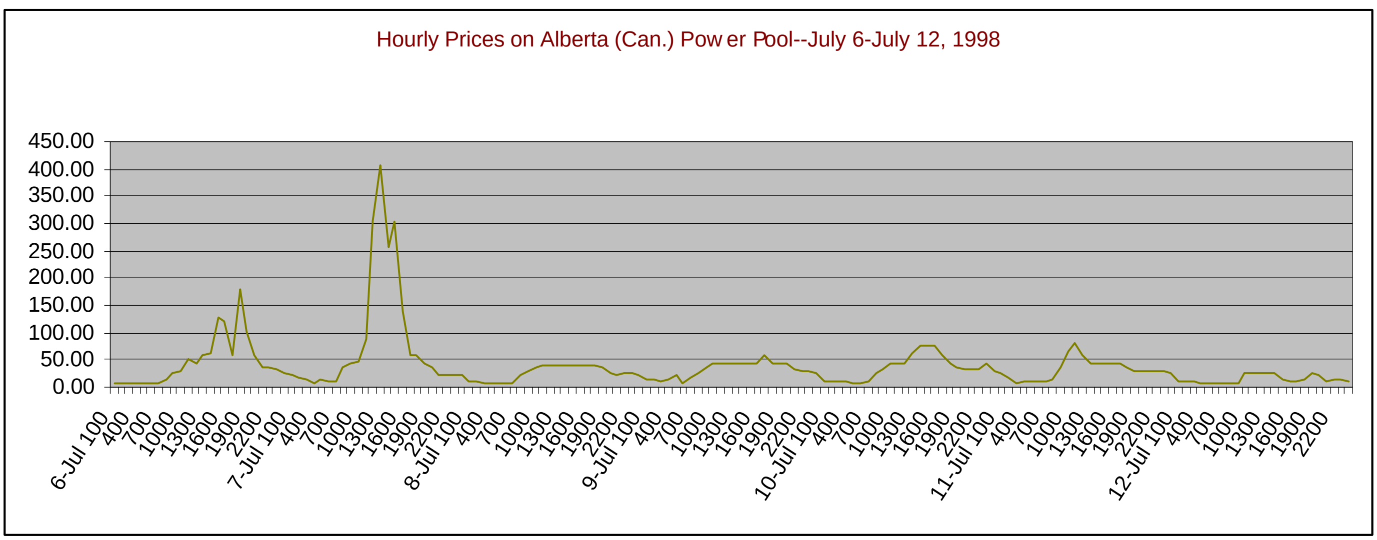
The wholesale power market is also permeated with subsidies, given that the fixed costs of utilities are still included in the rates of captive ratepayers, allowing utilities to sell power based only on the running costs of generation. This means that during most times, when capacity is in surplus, wholesale prices are unrealistically low in that the price does not include fixed costs associated with generation.

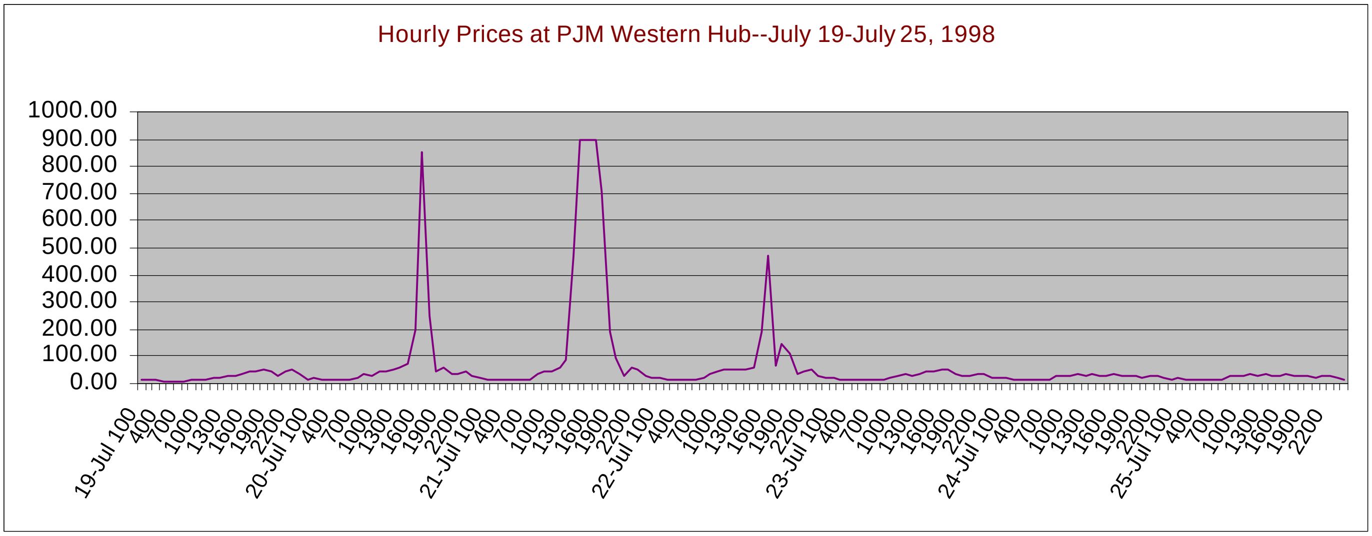
Wholesale power markets are largely, but not exclusively, decentralized, with trading occurring on an over-the-counter basis. Trading over the long-term is done on a variety of terms and bases; however, over the short-term, trading takes place under standard terms of monthly, daily, and hourly. The standard block of short-term power is 50 MW. It is significant to note that over-the-counter trading is not likely to be as efficient as some type of organized exchange structure, because, among other reasons, information as to supply, demand, and prices is not always readily available.

As the market develops it is rapidly approaching the structural form of other commodity markets, such as those for agricultural products and energy commodities like oil and natural gas. A single block of power may be traded many times (20-30 by some accounts) between marketers. Forward and future contracts are standard instruments of trading with many marketers selling power that they do not own. This, of course, amounts to speculation, but speculation is an established practice in all such markets. Financial derivatives of physical products are also a feature of the market.

The competitive wholesale market is also very volatile at times. Many traders might not have been surprised by prices around $1,000 per MWh, but the level that prices reached in June astounded most participants and observers. It should not be overlooked, however, that even disregarding the high prices of June, wholesale electricity prices often exhibit a degree of volatility rarely, if ever, seen in other commodities.

Below are prices during selected weeks from the Alberta (Canada) Power Pool and the PJM Interconnection's Western trading hub that illustrate the price volatility present in wholesale power markets. It should be noted that both of the cases below represent more organized markets for electricity; however it should not be presumed necessarily that the relatively lower prices compared to the Midwest in June are a result of the more organized nature of the markets.





The aftermath of the June crisis notwithstanding, wholesale power markets appear to be something of a "wide-open" marketplace. As of August 4, 1998, FERC had approved 571 entities for trading under market-based rates, 344 of which are independent power marketers. The remainder include affiliated power marketers, affiliated power producers, and investor-owned utilities. Many of the FERC-approved entities, particularly within the independent power marketer category, are small firms with questionable financial strength, and the vast majority are relatively inactive. During the first quarter of 1998, the top ten marketers in terms of sales accounted for approximately 61% of total sales. Total sales for the quarter reached 447 million MWh.

There are two sides to trading wholesale power, physical and financial. The physical market involves trading actual blocks of power for physical delivery, and this is what someone would most readily conceive of when imagining power transactions. Financial trading involves the buying and selling of financial instruments relating to the physical market such as call options for power. Under a call option, the buyer has the right to purchase (i.e., call) a specified amount of power at a set price during a stipulated period in the option agreement.

Power marketers and other trading entities can speculate in either the physical or financial markets through any number of methods.[13] Examples include selling power they do not possess for later delivery (hoping to cover their position at a profit by buying later), selling call options for power they do not possess, or, in the case of a load serving utility, selling power they own for delivery at a future time with the expectation that their power will not be needed to serve load.

Many transactions are not simple deals between two or three parties. As noted above, a block of power may be traded many times, leading to a situation where a chain of trading entities is formed. Such a situation increases financial risk to everyone in the chain due to the potential of default. Who gets hurt and to what degree depends on where a marketer is in the chain and whether a marketer is upstream or downstream of the defaulting party. A marketer that is not delivered power that was expected is forced to go out on the market to buy power to cover his obligations. As exemplified by events in June, this can be disastrous.

It is readily apparent that the competitive wholesale power market carries tremendous risk for trading entities, and this risk is not limited to those entities who are unsophisticated or financially weak.

Insights from the June Crisis

One fact made manifest by the episode in the Midwest is the tremendous level of uncertainty in electric power production. Uncertainty over demand, unit availability, weather, transmission availability, and the like is pervasive throughout the industry, and the financial risk

[13] Two examples of speculation, one in the physical market and one in the financial market are described below in the cases of Wabash Valley Power Association and City Water, Light and Power of Springfield, Illinois.

associated with this uncertainty is significant. The establishment of competition within wholesale power markets has only increased the level of risk by, among other things, introducing uncertainty as to the creditworthiness and financial soundness of marketers and financial practices used in trading. Events in the Midwest also give at least some indication that many market participants are unaware of or unprepared for the potential risks.

The Illinois utilities Commonwealth Edison Company (ComEd) and Illinois Power (IP) are obvious examples of the latter point. Suffering continuing capacity problems, ComEd began the summer relying on purchased power to provide approximately 25% of its needs, and when prices spiked in June, ComEd, was forced to pay as much as $6,000 per MWh for power.[14] Illinois Power suffered terribly as a result of the high prices. Illinova Corporation, IP's parent company, reported that power costs exceeded expectations by $49 million during the second quarter. Illinova has also stated that due to higher wholesale power costs in 1998, the company expects "modest, if any, earnings for the year."[15]

The experience of Wabash Valley Power Association (Wabash Valley), a cooperative generation and transmission utility, appears to epitomize the potential risks utilities face in wholesale power markets. On June 17, Wabash Valley made a 50 MW sale to Enron for the remainder of the month for $70 per MWh. The sale was made from resources acquired to serve native load. At the time of the sale, Wabash Valley saw no need for the capacity. Up to that time its maximum load for June had been only 641 MW, and it had procured 830 MW of capacity. A week later its peak load for June reached 748 MW, and over June 24-26, Wabash Valley's load soared to over 800 MW, peaking at 848 MWs on June 25. Wabash Valley's predicament grew worse when, in the midst of the crisis, they lost capacity they had purchased

---

[14] ComEd suffered, in part, from the outages at AEP, which forced that company to curtail a previously arranged sale of power to ComEd.

[15] Illinova News Release, July 15, 1998.

from AEP and other sources for several hours. Forced to purchase power in the hourly market, the association paid between $325 and $5,000 per MWh, which resulted in an approximately $4 million loss.

Clearly one portion of Wabash Valley's loss was out of its control, yet the remaining portion was of its own making even though it was unforeseen. That the association gambled and lost is the truth of the matter, regardless of how good the gamble appeared to be. When they needed additional power, they were at the mercy of the wholesale market. This appeared as something of a shock to Wabash Valley. In a memorandum to their members, the association remarked, "The old days where utilities would help each other are gone."[16]

This observation by Wabash Valley is a key to understanding the nature of competitive wholesale power markets. It also appears to be a factor overlooked by many market participants and analysts alike. Before wholesale power competition, utilities could, in general, rely on each other to provide short-term energy and/or capacity needs at reasonable costs. Both explicitly and implicitly, this was a sharing arrangement; explicit in the sense that deals were arranged on a cost or shared-savings basis, implicit in the sense that if a need developed, utilities could count on acquiring resources if a need arose even if they had no prior arrangements. It was to each utility's benefit to cooperate in this manner. In a sense, this cooperation was free or low-cost insurance, and it amounted to a significant benefit and cost saving. This is no longer so, and it is a profound change. Now each utility must bear the costs of hedging[17] its own supply.

A utility that does not cover its capacity requirements by either owning capacity or otherwise properly hedging its supply is exposing itself to the substantial risk of price volatility.

---

[16] Memorandum of Rick Coons, Wabash Valley Power to Directors, Managers, and Member System Representatives, July 8, 1998, attached to letter of Rick D. Coons to Chairman William D. McCarty, Indiana Utility Regulatory Commission, July 23, 1998.

[17] The MIT Dictionary of Modern Economics, fourth edition, 1992, defines hedging as "an action taken by a buyer or seller to protect his income against a rise [or fall] in prices in the future."

Indeed, given the correlation between power demand and weather, an unhedged position is in essence a bet against the weather. The experience of ComEd and Wabash Valley exemplify this concept. For example, when Wabash Valley sold 50 MWs to Enron, the cooperative exposed itself to a greater degree of risk.[18] A higher degree of risk implies greater returns when one guesses correctly and greater losses when one guesses wrongly. It is questionable whether the cooperative realized the nature of the risk involved.

The volatility of electricity prices is an inherent feature of competitive wholesale electricity markets, and the financial risk associated with this volatility must not be under-estimated. The events of June revealed the extent of the potential risk, and as a result, utilities, and marketers for that matter, should become more cognizant of this, and thus, employ practices to manage their risk appropriately. Anything less amounts to pure speculation in the market.

The episode also brought to light the inherent weakness of small marketers who lack sophistication and/or financial resources in such a potentially volatile market. The Springfield, Illinois municipal utility, City Water, Light and Power (CLWP), entered an arrangement with Federal Energy Sales, whereby CLWP purchased power call options from Federal Energy. The purpose of doing so was to act as middleman between Federal and other power buyers (in this case Southern Company Energy Marketing L.P., El Paso Energy Marketing Company, Louisville Gas and Electric Energy Trading Corporation, and PECO Energy Company), while assuming liability in the event of a default by Federal Energy Sales. When Federal defaulted in June, CLWP had no resources to make good its commitment; thus, it also defaulted. El Paso Energy has filed suit against CLWP seeking $7.4 million in damages, while Louisville Gas and Electric

[18] Of course utilities never know their demand exactly, so there will always be some degree of risk. Optimization of risk is the issue. It must not be forgotten either that a utility can secure too much capacity with the result of unnecessarily increasing costs. Ultimately, whether risk was properly accounted for is an empirical issue, the point here is that some utilities may not be employing suitable concepts of risk management.

has sued CWLP for $21 million. Southern Company also has filed suit for "damages in an amount to be proved at trial," although press reports state the Southern Company's contract was valued at $10 million. CLWP is trying to arrive at a settlement with PECO. Overall, CLWP netted a profit of $58,000 on the deals.[19]

The position in which CLWP found itself appears even more egregious considering that other traders had sensed the weakness of Federal Energy well before the marketer defaulted in late-June and ceased transacting business with the firm.[20] CLWP, of course, was not the only marketer harmed by Federal Energy's default, but considering the utility's size and the level of risk it faced, relying on a marketer such as Federal Energy only served to compound the potential risk that it undertook.[21]

The failures by Federal Energy Sales, The Power Company of America, and City Light, Water, and Power may not be the last failures seen in wholesale power markets, either. Analysts at Moody's Investors Service recently concluded that additional failures by marketers should be expected, noting that "…a small unaffiliated trader is less likely to be able to make it through a rough period than the large trading operations of investor-owned utilities or other larger multi-faceted corporations."[22]

It would be easy to surmise that large marketers are relatively immune from the risks faced by small marketers; yet, the experience of Louisville Gas and Electric Energy Corporation

[19] "CWLP Faces Second Lawsuit From Broken Deal/Another Company Sues Over Default," The State Journal-Register, July 16, 1998; "Energy Trading Deal In Illinois Goes Sour On Southern Co. Utility," The Atlanta Journal; The Atlanta Constitution, July 9, 1998, both articles obtained from Dow Jones Interactive.
[20] "Many marketers Saw Federal Fiasco Coming," MegawattWeek," July 6, 1998, p.1.
[21] According to The Wall Street Journal, September 1, 1998, Federal Energy Sales was forced to default when the hourly price of power exceeded $200 per MWh.
[22] "Power Markets' Recent Delivery Failures: Not Isolated Incidents," Moody's Credit Perspective, Volume 91, Number 29, July 20, 1998, pp. 3-4.

(LG&E) shows that even large and sophisticated power marketers can be consumed by the uncertainty and volatility of power markets.

On July 28, 1998, LG&E announced that it was closing its energy marketing venture, Louisville Gas and Electric Energy Trading Corporation. The major impetus in exiting the power marketing business appears to be a complicated long-term contract with Oglethorpe Power Corporation under which LG&E was to provide power at a fixed price to Oglethorpe in return for control of a portion of Oglethorpe's generation. Recent events have made that contract unprofitable. LG&E estimates that to sell or renegotiate all the contracts it entered will cost the company $225 million.

According to a report in The Courier-Journal of Louisville, Kentucky:

> "At the time [the contracts were made], LG&E was looking at an energy market that was entering deregulation. After studying what had happened to the prices of other commodities that have been deregulated and seeking the advice of consultants, LG&E entered contracts 'based on a market view that said prices were going to remain stable or fall,' [John] McCall, [executive vice president and general counsel] said.
>
> " 'The view was simply wrong.' "[23]

Several other utilities have followed the path of LG&E. Among them are Central Illinois Light Company (CILCO), which after losing $6.7 million in the second quarter, is absorbing the assets of its subsidiary QST Energy Trading, Incorporated and putting the unit up for sale. Similarly, Cinergy Corporation is reorganizing and scaling back its power trading division.

[23] "LG&E Found Energy Trading Brutal; Firm Folds Speculative Venture, Ending 80 Jobs," The Courier-Journal, July 30, 1998, obtained from Dow Jones Interactive.

Explaining the Surge in Prices

The June price spike was the combined result of very heavy demand due to an extensive heat wave in the eastern U.S., unforeseen capacity outages - due in part to stress on generating facilities by the heavy demand and damaging storms - and the nature of competitive wholesale power markets. More than anything, the price spikes were a natural market reaction to very heavy demand for an essential good that was in very short supply. This explanation, however, ignores a number of questions. The spectacular prices over June 24-26 seem too astounding to be explained by concepts of supply and demand or statements that "the market worked." Market participants and observers accept the particular circumstances of power demand and capacity availability that developed in the Midwest, but without other explanations, the level that prices reached seems to be just too incomprehensible.

It must be stated at the outset that, with respect to allegations of market manipulation through the withholding of power or transmission capacity, both time and resources preclude Staff from reaching a conclusion on these issues. It will necessitate significant effort and data to make any reasonable determination, and the charges are more likely to be resolved by the state commissions in the affected region or by FERC, if indeed any such resolution is possible.[24] To date, however, Staff has seen no evidence that such behavior played a role in causing prices to spike.

This is not to say that there are not serious concerns relating to transmission of wholesale power, particularly with respect to NERC's Transmission Loading Relief (TLR) procedures. These procedures are essentially regional curtailment policies that enable a utility to curtail transactions that are directly responsible for transmission overloads on its system. Many market

[24] In late-August, FERC requested data on sales and purchases in the Midwest during the week of June 22 from market participants who traded in the region during that week.

participants contend that TLR contributed to the volatility of wholesale prices, but these contentions are not necessarily related to specific wrongdoing by transmission owning utilities. Although such issues are, of necessity, beyond the scope of this report, at any event, they are peripheral to the events that occurred during the week of June 22.

One result of the price volatility in June was to call attention to power traders, both independent and utility affiliated. One of the first questions that comes to the fore is that of the share played by the defaults of several marketers in causing prices to spike. This is a difficult question to answer, because the failure of Federal Energy Sales and The Power Company of America coincided with forced outages as temperatures peaked. Separating the contribution of the marketers' failures from the other incidents cannot be done easily.

PECO Energy Company has offered comments in the FERC investigation of the crisis which appear to capture the market dynamics that led to the spike in prices.[25] Recalling the discussion of the wholesale market characteristics, there are two markets for wholesale power, the physical market and the financial market. Utilities, through their marketing arms or affiliates, and independent marketers routinely participate in both markets. According to the PECO observations, on Wednesday, June 24, prices spiked in the financially firm market.[26] (It should be remembered that the defaults by Federal Energy Sales began that day.) The next day, June 25, as temperatures and demand peaked, buyers who were short, i.e., committed to deliver power that did not own, entered into the hourly physical market to cover their positions. Prices skyrocketed at this point as marketers and utility traders in both the physical and financial markets began bidding the price of power higher and higher.

[25] PECO Energy Company Submits Observations re Price Spike in June under [FERC Docket] EL98-53.
[26] A financially firm purchase is a forward arrangement where a buyer acquires firm power and the seller, if unable to supply the power, is obligated to pay the cost of replacement power.

At this point, it is crucial to recognize that the prices that the market attained reflected not only the demand for power to serve load, but also the demand by marketers, including utility traders, to stave off the potential financial losses of their positions in both the physical and financial markets.

The most vociferous charges and complaints have been directed against "gouging" during the crisis by power marketers (either independent or utility-affiliated) who took advantage of the crisis to charge prices well above those usually encountered in the market. Opinions against such "gouging" are exemplified by the comments of John E. Hayes, Chairman of Western Resources:

> ". . . No one can be allowed to sell something that can be manufactured for less than $100 for as much as $5000-7000 (as has been done) when the only reason they are able to command that price is that the purchaser is buying the product in order to meet its public interest obligation."[27]

In the absence of specific examples, Staff, as noted above, is in a difficult position to judge on the prevalence of "gouging";[28] yet, given the evidence to date there seems little to justify such charges. Certainly, the prices of power during the week of June 22 were so high as to raise the concern of policy makers and many market participants alike, but charges of "gouging" seem to stem more from the fact that prices reached unexpectedly high levels, rather than specific instances of misconduct. There is no question that many utilities paid very high prices because of their public interest obligations, yet one must look beyond the mere evidence

[27] Letter from John E. Hayes, Jr. to Chairman James J. Hoecker, July 17, 1998, p. 1, found under Comments of Western Resources re Petition for Emergency Conference to be Convened by Cinergy Corporation under [FERC Docket] EL98-53.

[28] Illinois Power purports to have suffered when an unnamed counter-party quoted a price of $400 per MWh to the company and then charged $4000 per MWh after the energy flowed; see Motion of Illinois Power Company to Intervene in Support of Request for Emergency Conference and Request for Temporary Emergency Relief under [FERC Docket] EL98-53, June 30, 1998.

of the prices paid for power. Utilities that found themselves paying the highest prices for power during the week of June 22, in general, found themselves in that position by their own making.

One need not look far to find utilities that expected extraordinarily volatile prices during the summer of 1998. In a meeting on August 14, 1998, representatives of Virginia Power's Wholesale Power Group told Staff that, based on their analysis of capacity and potential weather conditions, they had expected very high prices for power during the summer. PECO Energy Company, in a FERC filing on August 12, called attention to the fact that the company had predicted in early June that the combination of a shortage of generation and extreme weather would produce a volatile market in wholesale power this summer.[29] Admittedly, it is doubtful that marketers expected prices at $5,000 or above (Virginia Power told Staff that they had expected prices around $1,000 or so), but it was clear to many that market fundamentals had the potential of yielding extreme prices. Indeed, such assessments should not have been simply the analysis of a selected few in light of NERC documents, such as those cited earlier in this report, that indicated the serious supply conditions facing the Midwest this summer.

Given such assessments it is very questionable as to how utilities such as Commonwealth Edison, which of late has sold off generating units and relied on wholesale power, or Wabash Valley, which sold firm power a week before the crisis, can be seen as victims of "gouging." Before such claims by a utility are taken seriously, one should investigate how that company had managed its capacity needs and its position (i.e., either short or long) in the wholesale market previous to the price spike.

Several market participants have offered the observation that prices reached such high levels in June, in part, because power markets have not been deregulated down to the retail level.

[29] PECO Energy Company Submits Observations re Price Spike in June under [FERC Docket] EL98-53.

Proponents of this view, among them Louisville Gas and Electric Energy Corporation and Enron Corporation, argue that until retail customers are exposed to prices in the marketplace and respond accordingly, there will continue to be the potential of extreme prices during peak periods as utilities struggle to meet their public service obligations. According to Kevin Hannon, president and chief operating officer of Enron Capital Trade Corporation, "We need them [end-use customers] to understand that power is costing $3,000 a megawatt hour so they can make economic decisions based on that."[30]

Such a view is more self-serving than realistic. It is terribly difficult to believe that any but the largest industrial customers would willingly choose to take the financial risk of paying several dollars per kilowatt hour for an albeit brief, yet unspecified period. In a completely deregulated market, retail consumers will likely demand some form of average pricing which in turn would be offered willingly by aggregators and other suppliers. Just as now, load-serving entities will be required to manage the financial risk of electricity supply on behalf of their customers.

[30] Quoted in "In Heat Wave, Power Trades Hit Records," The Wall Street Journal, June 29, 1998.

Conclusion

The price spike during the week of June 22 was the result of a combination of an unexpected lack of capacity and very hot weather over a very wide area for an extended period, and was, in fact, an understandable phenomenon. The significance of its occurrence lies in the revelation of the potential price volatility in a competitive wholesale power market.

Price volatility is an inherent characteristic of wholesale power markets and, despite the degree of volatility seen in June, will be dealt with more effectively by market participants, who can mitigate risks and respond appropriately to price signals, rather than by legislative or regulatory attempts to contain it. Price signals are meant, after all, to be acted upon by market participants. Appropriate actions may include construction of generation or utilization of proper risk management techniques, or any number of other means, but it is more likely that successful results will come through means such as these, rather than through regulatory or legislative actions to achieve politically desired outcomes.

Specifically with respect to the June crisis, the question arises as to whether the high prices were the result of "gouging" or rather a signal that additional generation is needed in the Midwest? If a policy response answers wrongly, the result may be much more serious than the price spike witnessed in June, and unfortunately, the economic consequences of any regulatory or legislative decision may become apparent only over time.

Recognition must also be made of the fact that a load-serving entity may be better off paying a high price for several hours in the wholesale market than building (and paying for) generation that will only be used for a brief period. Ill-conceived policy measures could interfere with such economically efficient decision-making on the part of such entities.

Deregulation on the retail level in the belief that wholesale price volatility will be mitigated would be a naïve response. It could be that the current condition of inertia in some states concerning regulatory policy may be hindering the addition of new capacity, due to utilities' reluctance to incur additional stranded cost exposure or laws or regulations that restrict the building of merchant plants. It can also be argued, as in the quotation above, that higher prices would restrict demand and alleviate potential shortages; however, these are fundamentally distinct concepts from the proposition that retail competition will alleviate supply and demand concerns or mitigate volatility on the wholesale level.

The establishment of independent system operators (ISOs) may be of benefit, in that ISOs should help regional transmission planning and procedures or may provide more organized exchanges for wholesale transactions. But ISOs will only mitigate volatility; they will not end it.

It is very difficult to say the extent of the role poor risk management procedures played in the volatility of wholesale prices during the week of June 22, but it seems apparent from the crisis that many utilities were not prepared for the potential risks in the wholesale market. One reason for the existence of forward markets is to reduce the risk of price volatility; yet, on the contrary, many utilities seem to have used forward markets inappropriately and increased their financial risk. The lack of preparedness of many market participants for the market they confronted in June may be the greatest lesson to be drawn from the crisis.