Indiana Utility Regulatory Commission

Staff Report

A Review of the Circumstances and Factors Which Resulted in Capacity Shortages and Price Volatility in Midwest Electricity Markets the Week of June 22, 1998

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I. Introduction

During the week of June 22, 1998, an unusual set of circumstances resulted in electric generation capacity shortages and unprecedented volatile prices. In an effort to understand these events the IURC held fact-finding meetings on July 22 and 23. These meetings were followed up by specific data requests to the utilities. This report presents the information and conclusions derived from those meetings and data requests responses.

II. Narrative of June Event

Following is an excerpt from the Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998, issued September 22, 1998. The FERC staff's narrative provides a broad perspective of the events. Information presented by Indiana utilities during the information-gathering meetings in July and in response to the subsequent data request will be used to illustrate how Indiana utilities faired during the critical period.

> During the week of June 22, 1998, wholesale electricity prices reached unprecedented levels. While prices as high as $10,000[1] per MWh were rumored, the highest price the team confirmed was an hourly price of $7,500 per MWh for a 50 MW transaction, paid by one Midwest utility for one hour. However, some utilities paid high prices for substantial quantities of electricity in both the hourly and day-ahead markets, with significant levels of hourly purchases at $3,000 to $6,000 per MWh.
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> Power prices edged up throughout the week as high temperatures continued to drive up loads. On Monday, June 22, next-day and hourly prices were already high (at least compared with prices up to that point), with next-day prices ranging from $80 to $200 per MWh. The default of Federal Energy Sales on Tuesday, June 23, was said to have driven up prices as market participants became concerned about whether they could meet their supply obligations. In the wake of the default of Federal Energy Sales, several other traders defaulted on contracts. On Wednesday, June 24, temperatures and loads increased and prices continued to escalate to over $1,000 per MWh.
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> To make matters worse, some Midwestern temperatures rose higher than

[1] 1 MWh = 1,000 kWh therefore $10,000 / MWh = $10 / kWh.

projected Wednesday night. On Thursday morning, June 25, hourly prices opened at around $1,000 per MWh. Prices escalated rapidly from $1,000 to $5,000 per MWh. By Thursday afternoon, hourly prices peaked at $7,500 per MWh. On Friday morning, June 26, prices began to fall, ranging from $1,500 to $3,500 per MWh. Prices decreased relatively quickly thereafter as temperatures decreased and loads subsided.

Set forth below are the significant events that occurred each day during the week of June 22 and a brief discussion of the individual factors that contributed to the price volatility during the week. The narrative is drawn from the trade press and the team's discussion with market participants.

Monday, June 22, 1998. The week began with high prices in both next-day and hourly markets, with hourly prices running higher than daily. For June 22, the highest day-ahead price reported was $200 per MWh into Cinergy. In contrast, blocks of power for 16 hours each day for the 5 business days of the week (16X5 sales) into the northern part of ECAR were priced much lower, at $65 per MWh. Day-ahead prices in the Southeast were up to $140 per MWh at Southern, $130 per MWh into TVA and $167 per MWh at the Florida-Georgia border. Prices rose more in anticipation of high temperatures and high demand in the southeastern United States than on predictions of hot weather in the East and Midwest.

Hourly prices in the Midwest on June 22 were reported as high as $400 per MWh in northern ECAR. This rise was attributed primarily to transmission loop-flow problems from Ontario Hydro into MECS. Hourly market prices into Cinergy were reported as high as $300 per MWh on the afternoon of June 22. These high hourly prices reportedly gave an incentive for marketers to sell power generated in PJM to markets in ECAR. Indeed, PJM reported that it was reducing its previous estimates of daily maximum native load by an average of 3,000 MW for the remainder of the week, implying that a comparable amount of generating capacity would be available for sale outside of PJM. Abnormally high temperatures in the Southeast also caused hourly market price increases of up to $275 per MWh at Southern, well over the reported high day-ahead for June 22 sales at Southern.

Tuesday, June 23, 1998. The reported high day-ahead prices for June 23 in Midwest markets ranged from $50.50 into north MAIN, to $90 in MAPP, $142 in Ameren, $190 into Cinergy and $275 into north ECAR. Trade press reports indicated that some market participants had been concerned whether high exports of energy from PJM would allow utilities within PJM to meet their native loads, but PJM apparently allayed these fears somewhat by its June 22 announcement that it would lower its estimated peak demand for the remainder of the week. Some traders also expressed concern about prices in MAPP during the latter part of the week: temperatures of over 100 degrees were predicted, while interruptions in transmission paths were already occurring and line-loading relief continued for the Eau Claire-Arpin transmission line. However, day-ahead prices for June 23 generally were highest in the Southeast, with the highest reported sales prices of $200 at Southern, $205 at the Florida-Georgia border and $225 into TVA because of heat-related demand. One marketer was reported to infer that such high prices into TVA meant that, at the end of the month, purchasers were genuinely short of power, rather than seeking to resell it.

On June 23, reports of Federal Energy Sales's default on its obligation,[2] combined with concerns about the unseasonably high temperatures, had thunderous repercussions on hourly electricity markets. Hourly prices thereafter substantially increased in a number of ECAR markets, especially into Cinergy.

Wednesday, June 24, 1998. Day-ahead prices for June 24 substantially increased in many Midwest markets over comparable June 23 prices. In light of Federal Energy Sales's reported defaults, concerns that other traders might not meet their contract commitments were said to drive up prices. *Megawatt Daily* remarked about Federal Energy Sales's reported default, that most marketers have predicted this type of scenario since last July, in the wake of $235 next-day power. In reaction to the price increases, some large marketers attempted to reduce their trading volumes until price fluctuations leveled off.

Other events reported to have increased day-ahead prices for June 24 were: Ontario Hydro's request in the afternoon of June 23 for transmission line relief; TVA's report of an all-time peak demand on June 22 and near record demand levels on June 23, and its predictions of a new record demand later in the week; and high temperatures in Entergy, where the market was described as severely short. *Megawatt Daily* noted that exports from PJM remained high, although the hot shutdown of PP&L's Susquehanna-2 nuclear plant (1,152 MW) was reported; a return of that unit to service was expected for the weekend. MAPP lost some generation when Northern States Power shut down its coal-fired 705 MW Sherburne County-2 unit to repair storm damage, although the Omaha Public Power District restarted its Gerald Gentleman-2 plant (648 MW).

The highest reported day-ahead prices remained stable for north MAIN ($50.50) and decreased in MAPP (from $90 to $78) compared with prices for June 23. However, the highest reported day-ahead prices increased for other areas: to $180 for Ameren, $325 for ComEd and into Entergy, $500 for north ECAR and $600 for Cinergy.

Intra-day prices into Cinergy on June 24 went as high as $1,400 per MWh, with the trade press speculating that a utility shorted by Federal Energy Sales was

[2] Federal Energy Sale's default on a contract with Springfield, Ill., resulted in further defaults by Springfield Water Light & Power.

bidding up the price. Some utilities were said to have bought power at whatever the market would bear to account for the disparities between available generation and predicted demand. As an example of price increases in the hourly markets on June 24, one trader cited a 16-hour transaction at market prices, with prices to be adjusted hourly. The hourly prices under this agreement went up from $17 to $1,000 per MWh.

Thursday, June 25, 1998. Federal Energy Sales's defaults, coupled with predicted high temperatures and electricity demand, reportedly led to some higher day-ahead prices for June 25, compared to day-ahead prices for June 24. In particular, traders continued to refer to uncertainty about whether marketers other than Federal Energy Sales would default. The highest day-ahead price into Cinergy rose to $1,200 per MWh, despite a reported prediction by Cinergy that its 1,300 MW Zimmer-1 plant would be back on line for June 25. While the highest day-ahead prices stayed stable in north MAIN, MAPP and Ameren compared with those for the previous day, and decreased in north ECAR (from $500 to $425), the highest reported day-ahead prices increased to $450 for ComEd and into Entergy, $495 for the Florida-Georgia border and $700 into TVA.

On June 25, hourly market prices in many areas of the Midwest soared far above the day-ahead prices. The price information submitted by utilities and marketers in response to the team's data request confirm the trade press's statement that $4,000 per MWh was a common hourly price in much of the Eastern interconnection on June 25. For example, one utility reported paying a high of $7,500 per MWh for 50 MW of energy on the afternoon of June 25. Another utility paid $6,000 per MWh for hourly energy that afternoon.

Traders acknowledged that part of the reason for the price spike was unplanned outages at a number of generating plants during the night of June 24-25, such as FirstEnergy's 962 MW Davis-Besse nuclear plant (as a result of tornado damage to transmission lines in the immediate vicinity of the plant) and Northern States Power's 855 MW Sherburne County-3 coal-fired plant (shut-down by storms, but then reopened June 25). Generating capacity available for Midwest markets further decreased when PJM interrupted power exports by declaring a maximum system generation emergency. A number of transmission facilities in MAPP and ECAR were also shut down by storm damage, including Eau Claire-Arpin lines. These outages reduced utilities' ability to transmit power among MAPP, MAIN and ECAR.

Some utilities reached generation emergency conditions on June 25. In at least one case, a utility in need of power contacted the control room of another to obtain power. Both parties agreed to the sale, but after the power flowed, a disagreement arose about the price of the power. The buyer claimed they agreed to $400 per MWh while the seller said the price was $4,000.

Friday, June 26, 1998. While the amount of hourly trading and hourly prices increased on June 25, day-ahead trading volumes for June 26 decreased. In light of the huge increases in hourly prices on June 25, sellers were said to discourage daily deals in hopes of being able to obtain high hourly prices again on June 26. Moreover, utilities reportedly did not want to enter into daily transactions for June 26 because they feared that such deals might endanger their ability to serve native load.

Day-ahead prices for June 26 reflected these developments: they were reported to reach unprecedented levels, but were lower than the highest hourly prices on June 25. Day-ahead prices per MWh climbed to maximums of $500 in MAPP, $1,300 in Southern, $2,000 into Entergy, $2,800 into ComEd, $3,600 into Cinergy and $4,900 into TVA. In contrast, the maximum reported per-MWh day-ahead prices for June 26 were stable for north MAIN, Ameren and north ECAR, as compared to the maximum day-ahead prices for June 25 for these areas.

On June 26, high heat again increased electricity demand to record or near-record levels for a number of utility systems. The trade press reported that Cinergy and MAIN had predicted trouble in meeting electricity demand that day; PJM again declared a maximum generation emergency and cut off power exports; Virginia Power predicted that demand would rise to near-record levels. However, hourly prices on Friday afternoon were reported to retreat rapidly from the record-breaking levels of June 25.

June 27-July 1, 1998. In the days following the huge price spikes, day-ahead prices decreased for the weekend days of June 27 and 28, going down to double-digit figures for many Midwest areas. The highest reported Midwest price were for sales into Cinergy: $100 per MWh on June 27 and $110 per MWh on June 28. In contrast, the maximum reported day-ahead price for purchases in Southern's region for these days was $1,000. Day-ahead prices for Monday, June 29, edged back toward the levels of June 25 and 26. By region, the maximum reported per MWh prices ranged from $90 in MAPP to $1,000 in Southern, $1,300 in north ECAR, $1,450 into Entergy, $2,000 into TVA and $2,500 into Cinergy. However, by Wednesday, July 1, day-ahead prices plummeted to levels that were well below the day-ahead prices of the previous week. Maximum Midwest day-ahead prices for July 1 were reported at $20 per MWh in MAPP, $50 into ComEd, $55 into Entergy, $60 into Cinergy and $70 into TVA.

III. Capacity Availability During the Week of June 22, 1998

As noted in the FERC staff's description of the June event, generally three factors combined to cause the capacity shortage in June. First, there was an unusual early summer heat wave (See Figure 1). This drove up demand at a time when utilities were already experiencing the healthy demand of a robust economy. Table 1 provides various peak demand information for the ECAR and MAIN regions. Second, strong storms and tornadoes had damaged generating stations and transmission lines throughout the Midwest. Third, since it was still early in the summer season, some generation capacity was still off line for scheduled maintenance.

Table 1

	All-time Summer Peak (MW)	June 1998 Peak (MW)	1997 Peak (MW)	1996 Peak (MW)
ECAR	91,254	89,642	89,847	89,424
MAIN	45,401	44,544	45,401	44,500
Total	136,655	134,186	135,248	133,924

Sources: NERC: 1998 Summer Assessment, pp. 22, 25; 1997 Summer Assessment, pp. 20, 21; NERC Hourly Demand Generation, and Interchange Data by Region.

Although, ECAR and MAIN predicted tight capacity supplies throughout the week of June 22, 1998, neither region exceeded the all-time summer peak or the 1997 peak. The concerns about capacity shortages were more a result of the amount of capacity that was off line at the time. Approximately 11,000 MW of generation capacity was unavailable in the ECAR region and 7,000 MW was unavailable in the MAIN region during the June event.

Indiana's electric utilities experienced similar demand and weather factors. Table 2 shows that only IMPA and WVPA exceeded their forecasted summer peaks during June. All other Indiana utilities reported June peak demands less than their projected 1998 summer peak. I&M and PSI faced critical capacity shortages, while SIGECO was a net seller of power during the June event.

Table 2

Utility	Peak Demand (MW) 1	Day and Time 1	Forecast Summer Peak (MW) 2
I&M	3,803	June 25 1400	3,914
IMPA	882	June 25 1600	860
IPL	2,758	June 25 1600	2,845
HE	877	June 25 1700	908
NIPSCO	3,055	June 24 1400	3,150
PSI	5,493	June 26 1500	5,644
SIGECO	1,140	June 25 1600	1,191
WVPA	856	June 25 1800	849

Source: 1) Peak Demand, Day and Time were provided by the companies. 2) Forecast Summer Peaks are from 1997 and 1998 Integrated Resource Plans except for HE, IPL and NIPSCO which provided their Forecast Summer Peak.

Table 3 illustrates the amount of capacity for Indiana utilities that would be expected to be available during peak periods; installed capacity and the amount of capacity that was available June 24-26, 1998. I&M shows the greatest shortfall in capacity due to the Cook nuclear plant being off line. PSI and NIPSCO also show significant shortfalls in available capacity. Other Indiana utilities had most of their installed capacity available.

Table 3 Available Capacity (MW)

Utility	Installed Capacity (MW) (1)	June 24 (2)	June 25 (2)	June 26 (2)
I&M	4,443	2,238 (50.4%)	1,738 (39.1%)	1,738 (39.1%)
IMPA	556	539 (97.0%)	539 (97.0%)	539 (97.0%)
IPL	2,956	2,869 (97.1%)	2,910 (99.4%)	2,949 (98.4%)
HE	1,243	1,186 (95.4%)	1,186 (95.4%)	1,186 (95.4%)
NIPSCO	3,392	3,195 (94.2%)	2,765 (81.5%)	2,755 (81.2%)
PSI	5,968	5,259 (88.1%)	5,266 (88.2%)	5,301 (88.8%)
SIGECO	1,236	1,217 (98.4%)	1194 (96.6%)	1127 (91.2%)
WVPA	156	150 (95.8%)	156 (100%)	156 (100%)

Source: 1) Installed Capacity from IURC 1996-97 Annual Report, except HE - capacity from the presentation handout.
2) HE and NIPSCO provided available capacity information in the presentation handouts from the July 22 and 23 meetings. For all other companies: Available Capacity was calculated by subtracting the weighted average unavailable generation, for the hours 700-1900, as provided in the data request responses, from the installed capacity. For I&M and PSI only generation owned by the respective utilities are included in the calculation, other AEP and Cinergy generation is not.

The high demands and scarcity of generation capacity forced utilities to curtail load, where possible, and then to meet the remaining demand through purchases on the spot market. I&M, PSI, HE and NIPSCO all called upon interruptible customers to curtail electricity loads June 24-26. When requested, NIPSCO customers accepted the interruption in their load supply. Some I&M and PSI customers and HE's single interruptible customer opted to "buy-through" instead of curtailing their electricity loads.

When an interruptible customer opts to "buy-through" it agrees to allow the utility to purchase power on the spot market on its behalf and pay the market price for the power instead of curtailing its load. This reduces the total electricity load the utility must provide and allows the resources to be used for other customers' needs. While the "buy-through" reduces the amount of electricity the utility has to generate or purchase, it does not reduce the total market demand for electricity and continues to influence the spot price.

Indiana utilities also used direct load-control DSM and made public appeals for voluntary conservation. Table 4 shows the load reductions resulting from customer interruptions and other direct load-control programs. Even with curtailments in customers' loads, Cinergy (PSI) and AEP (I&M) prepared to begin rolling blackouts but never had to implement them. Utilities in the MAIN reliability region faced similar circumstances. On June 25, 1998, Commonwealth Edison issued a public appeal for conservation in order to prevent implementation of rolling blackouts.

Table 4

Utility	Interruptible Customers	Interruptible Load (MW)	Actual Load Interrupted (MW)	Other DSM Loads (MW)
I&M*	9	370	Less than 370	0
PSI*	1	Up to 165	Between 66-143	0
WVPA	0	0	0	About 40
IPL	1	12	0	9-13
SIGECO	4	50	0	30
HE	1	3	3	0
NIPSCO	19	80-699	166	0
IMPA	0	0	0	4

Source: Company responses to IURC data requests. * The amount of load interrupted varied based on the time the request was made and the amount of the customers' load at the time.

Table 5 illustrates the Sales, Generation and Purchases of energy that Indiana utilities made during June 24-26. As expected, purchases contribute a major portion of the power supply for IMPA and WVPA since these entities own very little generation. Purchases were also an important source of supply for HE and I&M during those three days.

Table 5

Utility	Sales (MWh)	Generation (MWh)	Purchases (MWh)	Purchases/Sales (%)
I&M*	272,031	172,524	93,049	34.2
IPL	171,433	164,517	6,764	4.0
IMPA	54,769	28,811	25,958	47.4
HE	103,550	77,672	25,878	25.0
NIPSCO	192,210	187,196	5,014	2.6
PSI*	661,296	584,404	79,058	12.0
SIGECO	80,025	47,010	6,015	7.5
WVPA	59,842	10,656	49,186	82.2

Source: IURC data request responses. Total for the three days June 24-26. * I&M and PSI data is for the AEP and Cinergy systems, respectively.

It is not unusual for utilities to purchase power through long-term contracts to meet their supply needs but the combination of factors, high demand and a significant number of outages, brought more utilities to the spot market during the week of June 22, 1998. This, in turn, contributed to the price volatility experienced during that week. Table 6 shows the amount of purchases that Indiana utilities made from the spot market for June 24-26.

Table 6

Utility	Purchases (MWh)	Firm (MWh)	Non-Firm or Spot (MWh)	Spot/Total Purchases
I&M*	93,049	57,014	36,035	38.7%
IPL	6,764	5,836	928	13.7%
IMPA	25,958	18,784	7,174	27.6%
HE	25,878	21,502	4,376	16.9%
NIPSCO	5,014	0	5,014	100.0%
PSI*	79,058	1,600	77,458	98.0%
SIGECO	6,015	3,200	2,815	46.8%

WVPA	49,186	44,731	4,455	9.1%

Source: IURC data request responses. Total for the three days June 24-26. * I&M and PSI data is for the AEP and Cinergy systems, respectively.

Total spot market purchases for June 24-26 ranged from 928 MWhs for IPL to 77,458 MWhs for PSI. NIPSCO made all of its purchases from the spot market during those three days while WVPA made only 9.1% of its purchases from the spot market.

IV. Price Volatility During the Week of June 22, 1998

While generation capacity was in short supply the week of June 22, 1998, the wholesale spot market reached unprecedented price levels. After the fact, many market participants, including utilities, marketers and large industrial customers, raised concerns about how the market behaved during the June event.

A. Wholesale Power Market Prices

All Indiana utilities except one, SIGECO, fell victim to the volatile prices of the wholesale spot market. PSI had the dubious distinction of paying the highest price for power, $7,500 / MWh on June 25. The other utilities paid prices ranging from $1,540 - $5,000 / MWh. SIGECO was a net seller of power during the shortage and sold power for as much as $3,750 / MWh for a short time on June 25.

During the week of June 22, 1998, I&M, NIPSCO, IPL and IMPA all exercised curtailment provisions of their supply contracts with wholesale customers. Generally, these power sales were contingent on generation unit availability. If the unit is not available, there are no financial consequences if the power is not supplied. Only I&M was forced to curtail a firm power sale that resulted in liquidated damages.

Conversely, WVPA, IPL, I&M, SIGECO, IMPA, HE and NIPSCO all failed to receive power supplies during the capacity shortage. IPL, I&M and SIGECO were due compensation by the supplier for failure to deliver the power.

B. Transmission Constraints

Three Indiana utilities, PSI, I&M and NIPSCO, noted that transmission constraints prevented them from transferring power. PSI was affected by Transmission Loading Relief called by the Security Coordinator on June 22 and again on June 26 due to problems on the Ontario Hydro-Michigan transmission system.

I&M reported that on several occasions power sales had to be limited or reduced as a result of transmission limitation in other systems, but only a portion of the existing flows were affected. The prevailing pattern of flows affected were those from east/southeast to west/north.

NIPSCO was affected by transformer limit restrictions at the Kammer and Belmont substations and also due to a large circulating flow around Lake Erie. Storm damage at the Davis-Besse plant and on the 345 KV Arpin-Eau Claire line also limited NIPSCO's power transactions.

V. IURC Inquiry

To gain a better understanding of why the capacity shortage occurred and what actions could be taken to prevent it from happening again, the IURC followed up its July meetings with a data request to all Indiana utilities. Along with a request for further documentation on the events of the week of June 22, 1998, the IURC issued questions designed to gain information about how to prevent a similar event in the future. These questions covered a variety of topics including maintenance and staffing practices, the effects of new/inexperienced market participants, deterrents to new capacity construction and the possible benefits of new institutions such as an Independent System Operator or a Power Exchange.

A. Facility Maintenance and Staffing Practices

1. Maintenance

Over the past five years almost all of Indiana's utilities have changed their generation maintenance practices. Generally, the intervals between large-scale maintenance projects have increased from every 6 to 12 months to every 12 to 18 months, with some extending as long as 24 months. The utilities claim that the revised maintenance schedules have improved the availability of the generating units. Information of annual equivalent availability by generating unit solicited through the IURC data request show that the availability of generation capacity for Indiana utilities is usually good and has not shown any discernable change over the last ten years.

In the FERC staff's report on the June event, it was noted that some generation capacity was not available at the time because it was off line for scheduled maintenance. This was not the case for Indiana utilities. Other than some very short periods of maintenance by SIGECO all other generation capacity off line was due to forced outages. It should be noted that there are some differences on how utilities define a planned or scheduled outage versus a forced outage. For example, the unavailability of the I&M's Cook plant is considered to be a forced outage even though it is a long term and known outage. Generally any outage that is not planned or scheduled by the utility is considered a forced outage regardless of the length of time of the outage or the circumstances.

For transmission and distribution facilities, I&M, PSI and NIPSCO indicated that their maintenance practices had changed over the last five years. The utilities are now using reliability-focused techniques. Reliability focused techniques of planning transmission and distribution facilities maintenance are based on maintaining system reliability as opposed to scheduling maintenance on a time interval schedule. Transmission and distribution facilities owned by Indiana utilities were not a factor during the week of June 22, 1998.

2. Staffing

In conjunction with information on maintenance practices by the utilities, the IURC solicited information about changes in maintenance staffing levels at the utilities. All the utilities indicated there had been some decrease in staffing levels. Most stated that maintenance workers were now being trained in multiple skills and were, therefore, better able to handle a greater variety of maintenance tasks and outage problems. It is not clear if the reduced staff levels in any way affected the ability of any Indiana utility to bring generation capacity back on line when forced out during the June event.

B. New Entrants/ Marketers and Brokers

When questioned, Indiana utilities did not feel that new entrants such as marketers or brokers contributed to the supply problems during June. I&M stated that the supply problem did not specifically result from new entrants in the market. The new entrants, some of whom apparently made firm commitments without appropriate hedges, may have added some confusion in the market, and, therefore, may have affected the pricing. However, IPL and SIGECO suggested that more stringent certification standards should be required before allowing a marketer or broker access to the wholesale power market. This is consistent with what was reported in the FERC staff's report.

C. New Capacity Construction

It was evident in the FERC report and in the information collected by the IURC that generation reserve margins are declining in Indiana and throughout the Midwest. Two Indiana utilities indicated that they would consider building peaking capacity but Indiana's Certificate of Need Law was a discouraging factor. The time and money needed to meet the requirements of the law in order to get a certificate discourages the utilities from following through on their construction plan. Also, utilities indicated that the uncertainty regarding the future of the electric utility industry; i.e. if and when restructuring, competition, deregulation take place; discourages large capital investments at this time.[3]

[3] Since the July meetings and the subsequent data requests, IPL and SIGECO have filed petitions to construct new capacity. The details of these proposals have yet to be filed with the IURC.

D. New Market Institutions

In the data request the IURC questioned the utilities about the benefits of an Independent System Operator and Power Exchange in preventing the capacity shortages and price volatility witnessed in June.

PSI, WVPA, IMPA and HE felt that an ISO could have prevented or alleviated the transmission constraints experienced during the week of June 22, 1998. It was noted that in the short-term, an ISO would have a broader scope of information available so that transmission constraints could be prevented or bypassed. In the long-term, an ISO could provide planning services that would prevent or correct constrained lines. I&M, NIPSCO and IPL did not believe an ISO would have prevented or alleviated the transmission problems experienced in June. SIGECO did not feel it had enough information about the constraints to comment.

Utility responses to questions about the benefits of a regional power exchange tended to be negative or uncertain. PSI, IPL, I&M, SIGECO and NIPSCO said that a regional power exchange would not have alleviated the extreme price fluctuations observed during the week of June 22, 1998. WVPA stated that a power exchange might be one facet of a multi-faceted solution to such problems. IMPA suggested that a power exchange could improve the price transparency of the spot market. HE was uncertain of the benefits of the regional power exchange.

E. Information Availability and Accuracy

In the data request the IURC asked a number of questions that related to information availability and accuracy. These questions related to topics such as the calculation of Available Transmission Capacity, the OASIS system and price transparency of the spot market.

During their presentations at the July information-gathering meetings, some utilities suggested that the calculation of ATC or other strategies were being used by transmission-owning utilities to hoard transmission capacity. No evidence was presented to support this assertion and when asked if a standardized method of calculating ATC would be useful, the utilities were unenthusiastic about the proposition.

On the questions about the OASIS system, all Indiana utilities stated that the system performed well during the June event. However, several utilities noted that maintaining OASIS information was time-consuming and tedious. I&M also noted that there seemed to be a tendency for some marketers to make speculative reservation requests for a variety of transmission paths, later confirming some and withdrawing others as power transactions were made and confirmed. I&M stated that this entailed excessive transmission provider time and resources to analyze and respond to each request and tied up pathways for which requests are later withdrawn.

When questioned about the price transparency of the wholesale market the line seemed to be drawn between the larger investor-owned utilities and the smaller customer-controlled entities. HE, WVPA and IMPA did not feel the wholesale power market price was sufficiently known and transparent. All other respondents believed it was.

F. Misconduct and Market Manipulation

During the information-gathering meetings in July, there was some suggestion that there may have been inappropriate communication between some utilities and their marketing affiliates. There were other claims that transmission capacity availability was used to manipulate the wholesale spot market. The IURC was interested in reviewing evidence of these actions but no verifiable information was produced in either the July meetings or the responses to the subsequent data request.

The FERC staff reported similar allegations in its investigation of the June event. While the FERC staff found no direct evidence of market manipulation, the staff suggested that these allegations may warrant further investigation.

VI. Conclusions

The week of June 22, 1998, proved to be a trial by fire for Midwest utilities. The capacity shortage brought several utilities throughout the Midwest to the point of rolling blackouts and many utilities bought power at exorbitant prices, but ultimately the lights stayed on throughout the region.

The FERC staff found that the particular combination of events that led to the magnitude of the June 1998 price increases is not likely to recur, although wholesale prices can be expected to rise and fall as a result of the dynamics of supply and demand. Moreover, the report concluded that over time participants in the wholesale electric market can be expected to develop effective ways to limit their exposure to future volatility. However the FERC staff did suggest several issue areas for consideration:

1. Market Monitoring and Assessment - Reexamination of the FERC’s monitoring activity to assess whether new competitive markets are functioning properly.

2. Compliance Actions - Review how to maximize compliance with the requirements and policies of Order 888 and 889, including standards of conduct, and prevent or

redress any attempts to manipulate the market or circumvent the FERC's rules governing the interstate electricity industry.

3. Price Discovery and Reporting - Consideration of the development of real-time reporting of the prices for and availability of wholesale power and interstate transmission.

4. Regional Entities - Further steps to promote the growth of regional entities that would independently operate transmission systems and plan and coordinate transmission could address key issues.

5. Cooperation with Other Key Players - The Commission, the States, NERC and other relevant entities must maintain open communication on ways to use their respective authorities or organizations to help ensure that power markets function efficiently.

The information gathered in the IURC's investigation of the June capacity shortage and price spikes were generally consistent with data compiled by the FERC's staff. The events of June 1998 emphasized the need for additional capacity in the ECAR region and specifically in Indiana. This capacity need, particularly for peaking generation, was forecast by the State Utility Forecasting Group.[4] In October 1998, SIGECO filed a petition for a certificate of need for a 42 MW cogenerator and in December IPL filed a request to construct 200 MW of peaking capacity. In January 1999, AES filed a request to build 400 MW of generation capacity. Also, there have been informal contacts with other entities which indicate an interest in constructing additional capacity in Indiana.

The IURC Staff believes that the presence of an ISO or other regional transmission entity would have mitigated the events of June 1998. A Power Exchange or other means of real-time price discovery would have also helped to alleviate the problems that occurred.

4 1996 Indiana Electricity Projections, State Utility Forecasting Group, October 1996.

Acronyms and Definitions

AEP - American Electric Power, parent company of Indiana Michigan Power Company (I&M).

Ameren - Merged parent company of two electric and natural gas utilities, Union Electric in Missouri and Central Illinois Power in Illinois (now known and AmerenUE and AmerenCIPS).

Available Transmission Capacity (ATC) – A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Buy Through – An option to interruptible customers that requires the utility to purchase power for the customer on the spot market rather than cutting off the customer's electricity. The customer usually pays the going market price for power when requesting a buy through.

Cinergy - Parent company of PSI Energy.

ComEd - Electric utility serving 3.4 million customers in Chicago and northern Illinois.

Curtailment – The reduction or stoppage of a power delivery due to unavailable generation capacity or transmission constraints.

Default - The inability to make delivery on a power supply contract due to lack of coverage. The term generally refers to marketers or brokers that do not own or control generation capacity.

DSM - Demand-Side Management; programs designed to reduce electric usage. Direct Load-control DSM is a program where the utility has control over the electricity supply to a specific appliance such as a water heater or air conditioner.

Eastern Interconnection – The bulk electric system network in North America, comprising the area east of the Mississippi River.

ECAR - East Central Area Reliability Coordination Agreement, a regional council of NERC, including Indiana, Michigan, Ohio, Kentucky, West Virginia and parts of Pennsylvania, Maryland and North Carolina.

Entergy - Energy company with about 2.5 million customers in Arkansas, Louisiana, Mississippi and Texas.

FERC - Federal Energy Regulatory Commission.

First Energy – Headquartered in Akron, Ohio, serving 2.2 million customers of four operating companies in central and northern Ohio and western Pennsylvania.

Generation Deficiency Alerts – A notice issued by a utility when its ability to meet customer demand appears to be in jeopardy.

HE - Hoosier Energy Rural Electric Cooperative.

I&M - Indiana Michigan Power Company, subsidiary of AEP.

Independent System Operator (ISO) – An independent entity that operates a regional transmission system to ensure a reliable power supply.

Interruptible Customers – Electric customers that agreed to have some or all of their electricity cut off under conditions specified in their contracts.

IPL - Indianapolis Power & Light Company.

IURC - Indiana Utility Regulatory Commission.

Liquidated Damages Contract – Any contract with a provision which obligates the seller of power to pay the buyer’s replacement energy costs in the event that the seller fails to deliver the contracted for energy.

Loop Flow - The actual flow of electrons based on the laws of physics. In contrast, contract path is a defined flow of electrons for purposes of a business transaction.

MAIN - Mid-American Interconnected Network, a regional council of NERC, including Illinois, Wisconsin and part of Missouri.

MAPP - Mid-Continent Area Power Pool, a regional council of NERC, in the upper Midwest of the U.S.

MECS - Michigan Electric Coordinated Systems.

MWh - Megawatt-hour.

MW - Megawatt, one thousand kilowatts or one million watts.

NERC - North American Electric Reliability Council, the national coordinating industry group responsible for transmission reliability.

NIPSCO - Northern Indiana Public Service Company.

OASIS - Open Access Same-Time Information System. The electronic system by which transmission owners/operators are required to provide information about available transmission capacity, prices, etc. that enables users to obtain open-access non-discriminatory transmission service.

PJM - Originally, the Pennsylvania-New Jersey-Maryland Power Pool. Today, PJM is the largest centrally dispatched power pool in North America, managing the wholesale bulk power grip in the mid-Atlantic region.

Power Exchange – A public auction for electric power in which producers compete to sell their power. The Power Exchange will match the sales offers with purchase requests submitted by utilities, power marketers and brokers on behalf of customers.

PP&L - Provides electric service to 1.2 million customers in eastern and central Pennsylvania; and trades or markets wholesale energy in 25 states and Canada.

PSI - PSI Energy, subsidiary of Cinergy.

Reliability Focused Techniques – Methods of planning transmission and distribution facilities maintenance that are based on maintaining the system reliability as opposed to the scheduling maintenance on a time interval basis.

Reserve Margin (Operating) – The amount of unused available capacity of an electric power system at peak load for a utility system as a percentage of total capability.

Rolling Blackouts – An option used by utilities to maintain the reliability of the electric system by shutting down the power supply to specific areas for specific periods of time and then returning the power and blacking out another section of the system.

Security Coordinator – The entity with responsibility and authority for directing the implementation of operating action to maintain bulk transmission security for a control area.

SIGECO - Southern Indiana Gas & Electric Company.

Southern (The Southern Company) – Large holding company of five electric utilities in the south, including most of Georgia and Alabama, southeastern Mississippi and the panhandle region of Florida.

Transmission Loading Relief (TLR) – A NERC procedure implemented by the security coordinator when the transmission facilities within his security area are about to exceed, or have exceeded, their operating security limit (i.e., a transmission line is overloaded). The procedure has six levels, which involve curtailing various types of transactions depending on the severity of the problem.

TVA - Tennessee Valley Authority, a federal government-supported power agency.

WVPA - Wabash Valley Power Association.