INVESTIGATION OF BULK POWER MARKETS

MIDWEST REGION

November 1, 2000

The analyses and conclusions are those of the study team and do not necessarily reflect the views of other staff members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself

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1. Overview

The Midwest region is dominated by vertically integrated transmission providers, each having control over their own transmission and generation functions, serving their own native load. As such, they have weak economic incentives to provide access to transmission service to third-parties and strong incentives to favor their own services. During this investigation, Staff received many complaints from market participants concerning barriers to transmission access, including curtailments, lack of standardized protocols for providing information and handling interconnection requests, and discriminatory conduct. Some of these we have been able to substantiate independently. What is not clear is whether these transmission access problems are wide-spread or a collection of isolated incidents, and whether the appropriate regulatory response should be more aggressive enforcement of existing rules or whether the rules need to be adjusted. A lack of systematically maintained and readily available information about the markets in the Midwest makes it difficult to address these issues, thereby, in itself, creating an inefficiency. As discussed in this Report, at the very least, these complaints indicate a lack of confidence in the bulk power market and the ability of market participants to rely on transmission access, harming the liquidity of the market.

For purposes of this report, the Midwest refers to the four NERC regions ECAR (East Central Area Reliability Council), MAIN (Mid American Interconnected Network), MAPP (Mid-Continent Area Power Pool), and SPP (Southwest Power Pool).[1] Geographically, this area comprises the western parts of Pennsylvania and all of West Virginia moving westward to the Dakotas, Nebraska, Kansas, and Oklahoma, as well as parts of Arkansas, Louisiana, and Texas.

Power systems in this large, diverse geographic area evolved through the connection of vertically integrated investor-owned utilities (IOUs), municipal power systems and cooperatives. Initially, adjacent systems became linked by transmission lines in order to increase reliability through sharing expensive generating capacity during emergencies. All bulk power transactions are currently bilateral, with no central clearing site, power exchange or centralized dispatch center.

Table 2-1 below lists the states comprising each of the four regions.

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[1] Entergy is included in the Southeast region.

Table 2-1. Subregions of the Midwest

Region	States
ECAR	Indiana, northern, central and western Kentucky, Ohio, Michigan, West Virginia, western Maryland, western Pennsylvania, and southwestern Virginia
MAIN	Illinois, western part of the Upper Peninsula of Michigan, eastern Missouri, and eastern Wisconsin
MAPP	Iowa, Minnesota, western Montana, Nebraska, North Dakota, South Dakota, western Wisconsin, Manitoba and Saskatchewan
SPP	Western Arkansas, Kansas, parts of Louisiana, southeastern New Mexico, Oklahoma, parts of the Texas panhandle and part of northeastern Texas.

Generally, data in this report are segregated by NERC region, with aggregate data and analysis for the entire Midwest provided where appropriate.

2. Supply and Demand

A. Description of the Midwest

SPP was formed in 1941 when 11 power companies voluntarily joined together to pool resources during World War II. After the war ended, the Executive Board of the SPP, recognizing the increased benefits of interconnection, decided to keep the organization together. MAPP was formed in the mid-1960s for similar reasons and approved in its current form in 1972, followed by MAIN in 1964. ECAR was formed in 1967 as a reaction to reliability, inter-connection and inter-dependence issues arising out of the Northeast Blackout of 1965. The NERC region of MAPP also includes two Canadian Provinces.

Table 2-2 describes the four regions in the Midwest by population, land mass and NERC characteristics. The participating members are IOUs, cooperatives, municipals, non-utility generators (NUGs) and federal and Canadian government agencies. Control areas are discrete parts of an electrical region which control transmission. Some control areas are quite large, but others are small—electrical "city states." Security Coordinators oversee the control areas on matters of electrical reliability and stability.

Table 2-2. Physical Information about the Midwest [2]

Region	Number of Members	Square Miles	Population (millions)	Control Areas	Security Coordinators
ECAR	50	194,000	36	15	3
MAIN	43	150,000	20	13	1
MAPP (all)	105	900,000	18	16	1
SPP	54	400,000	18	17	1
Total	252	1,640,000	92	61	6

Source: Home websites for each region.

The four regions can be categorized along obvious physical characteristics. For instance, ECAR and MAIN are both physically smaller than the other two regions. However, they are more densely populated as Chicago, Cincinnati, Cleveland, Detroit, Indianapolis, Pittsburgh and St. Louis all lie in these two regions. ECAR, however, has the most electrical generation, capacity and transmission. MAPP and SPP, on the other hand, are much bigger geographically with lower population densities, electrical loads and

[2] NERC 2000 Summer Reliability Assessment and Regional Web Sites.

capacities. The combined load of the four regions accounts for 39 percent of the Eastern Interconnection.[3]

B. The Physical Transmission System

The transmission system is a typical grid which evolved for reliability purposes to share generating capacity between adjacent utilities and to reduce generation investments. The majority of assets are owned by vertically integrated IOUs. No single entity operates or owns the transmission system in the Midwest. As will be discussed in Section 4, while there are three proposals for Regional Transmission Organizations (RTOs), the Midwest ISO, the Alliance RTO, and the Southwest Power Pool RTO, there are currently no ISOs or RTOs in this region.

There are 61 different control areas in the Midwest, usually co-located with the control center of the dominant IOU in the area.   There are also six NERC Security Coordinators (SC) who have the responsibility and authority to enforce stability and reliability conditions on the grid.   ECAR has three of these Security Coordinators and the other three regions each have one.

The current transmission system was not designed to transfer power over long distances (between and across regions) as envisioned by Open Access (Order Nos. 888, 889 and 2000).   Consequently, electric power flows in patterns and quantities not anticipated by the systems' designers. The increasing amount and number of transactions across regions results in exacerbated loop flow, voltage drop, and line overload problems. In fact, the complexity and magnitude of the interconnections can, at times, overwhelm the electronic and software tools used to model and manage power flows on the grid.   When the grid becomes congested, it is necessary to use curtailment procedures known as Transmission Loading Relief (TLR), especially in light of the current absence of a congestion management system for any significant section of the region.

Figure 2-1 indicates the location of major electrical transmission lines, those above 230 kV, in each region of the Midwest.

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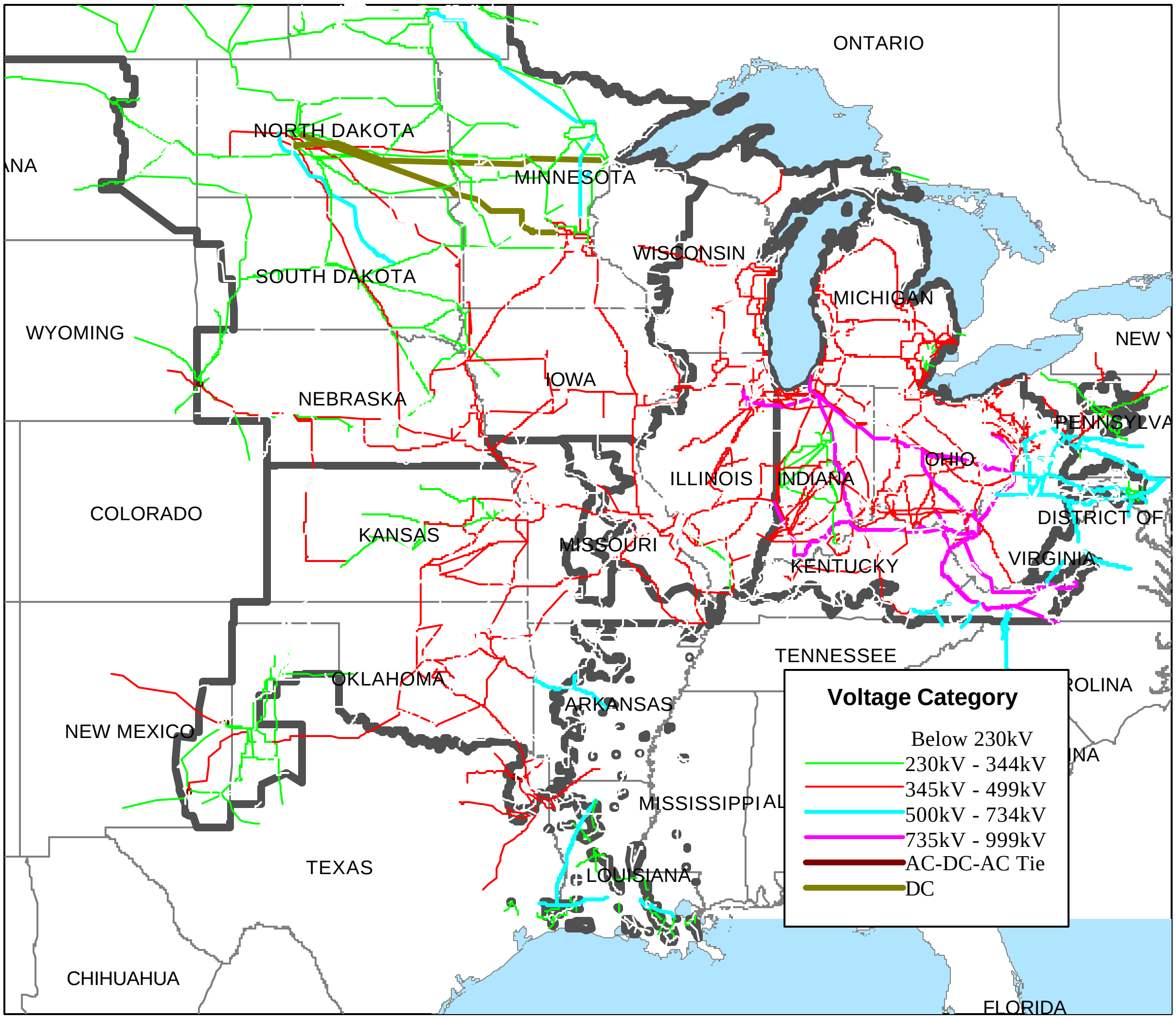
[3] NERC 2000 Summer Reliability Assessment.

Figure 2-1. High Voltage Transmission Lines in ECAR, MAIN, MAPP and SPP



Source: RDI Powermap, August 2000.

Table 2-3 shows the milage of major electrical circuits (above 230 kV) in each region and the total for the Midwest. ECAR and MAPP each have approximately 15,000 miles of circuits while MAIN and SPP each have roughly 6,000 miles. The total for the Midwest is 43,277 miles of high-voltage circuits. The third column lists the NERC projections for the construction of additional circuits in each region, over the next 5 years. Overall, NERC projects 1,526 miles in incremental additions. The last column shows the percentage increase these additions would provide, if all transmission projects are completed in their entirety.

Table 2-3. Circuit Miles and Projected Additions 2000-2004

Region	Transmission Circuit Miles 230 kV and Above		
	2000 Existing	2000–2004 Additions	Percentage Increase
ECAR	15,843	301	1.9
MAIN	5,699	303	5.3
MAPP - US	15,236	494	3.2
SPP	6,499	428	6.6
Total	43,277	1,526	3.5

Source: NERC (Draft) Reliability Assessment 2000-2009.

C. Transmission Loading Relief (TLR)

Transmission Loading Relief (TLR) is perhaps the most important transmission issue in the Midwest. The TLR is a NERC procedure used to mitigate potential or actual violations of the operating limits on flowgates in the Eastern Interconnection. These procedures are an escalating series of actions to reduce the electrical flow across a flowgate. A flowgate is a combination of transmission equipment, such as transformers and transmission lines, which has been identified by transmission providers as a critical element requiring continuous monitoring. Transmission operators are supposed to begin the TLR procedure when they notice the amount of power moving across a flowgate is approaching one of its thermal limits. When this happens, transmission operators notify the Security Coordinator in their control area who "calls" the TLR beginning at Level 1. This first level is simply an advisory to other Security Coordinators that a problem has been observed. Potential or existing transactions are affected if the Security Coordinator escalates the TLR to Level 2 or higher.

Table 2-4 describes the nine levels of TLR events and the remedial actions taken to reduce the inadvertent electrical overload at the affected flowgate.[4]

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[4] The TLR definitions and levels used in this report are detailed in NERC's Operating Procedure No 9. NERC changed the procedures and levels for TLRs on October 12, 2000, and documented those changes in Appendix 9C1, Transmission Loading Relief Procedure–Eastern Interconnection. The procedures and levels described above are those that were in effect prior to October 12, 2000.

Table 2-4. TLR Levels and Remedial Actions Taken at Each Level

TLR Level	Action(s) to Alleviate Congestion
Level 1	Notify security coordinator of potential violation
Level 2a	Hold transfers at current levels
Level 2b	Reallocate firm transactions
Level 2c	Reallocate non-firm transactions
Level 3	Curtail non-firm transactions
Level 4	Reconfigure and redispatch
Level 5	Pro rata curtailment of firm transactions and network service
Level 6	Implement emergency procedure
Level 0	TLR event concluded

Source: NERC Operating Procedure 9.

Table 2-5 shows the growth in peak load by region since 1998. The percentage change for the 2-year period is in the last column. All regions show a decline in peak load from 1999 to 2000, probably due to the milder weather in the summer of 2000.

Table 2-5. Growth in Peak Load, 1998-2000
(Megawatts)

Region	1998	1999	2000	Percentage increase 1998 to 2000
ECAR	91,605	96,149	93,150	1.7
MAIN	46,824	49,027	48,402	3.4
MAPP	36,024	37,196	33,585	-6.8
SPP	36,230	37,809	37,309	3.0
Total	210,683	220,181	212,446	0.8

Source: NERC Summer Assessment and Staff Data Request.

As for supply sources, the region as a whole has seen growth in new generation since the price spikes of 1998. Table 2-6 shows the increase in electrical generating capacity, by region, since 1998. The second and third columns indicate the combined megawatts of all units completed in a region in 1999, and in 2000. The fourth column is the sum for these 2 years, or the total addition to capacity, in megawatts for each region.

The last column is the percentage increase over the 2-year period. As shown below, the growth in peak load since 1998 has been less than the increase in capacity, resulting in an increase in reserve margins regionally.

Table 2-6. Increase in Generation Capacity

Region	Additions to Capacity		Total (MW)	Increase since 1998 (percent)
	1999	2000		
ECAR	1,362	1,550	2,912	2.5
MAIN	1,399	2,627	4,026	7.2
MAPP	264	102	366	0.8
SPP	376	1,415	1,791	3.6
Total	3,401	5,694	9,095	3.4

Source: RDI Powerdat, August 2000.

Two regions responded to a Staff data request for this report with different capacity addition figures: ECAR reported 4,958 MW of additional generating capacity, which was more than the RDI estimate. On the other hand, MAPP reported only 139 MW of additional generating capacity, which was less than the RDI estimate. Using the data request numbers yields a 4.2 percent increase for ECAR and 0.3 percent increase for MAPP. Whichever figures are used, it appears there has been a significant increase in Midwest generation capacity since 1998.

3. Events of 1998 to 2000

A. Events of 1998

During the week of June 22-26, 1998, the wholesale electric markets in the Midwest experienced a dramatic price increase. This price spike was caused by a combination of factors.[5] First, the temperature was unseasonably high across a very large area for a substantial period of time. The elevated temperatures translated into increased demand for electricity. Second, the available generating capacity was lower than normal due to a number of planned power plant outages. Furthermore, a powerful storm in the Midwest caused significant unplanned transmission line and plant outages. Also, there had been no significant additions in new generation capacity in the Midwest for some time. Third, transmission system constraints in other parts of the grid reduced the ability to move power to the Midwest from adjacent regions.

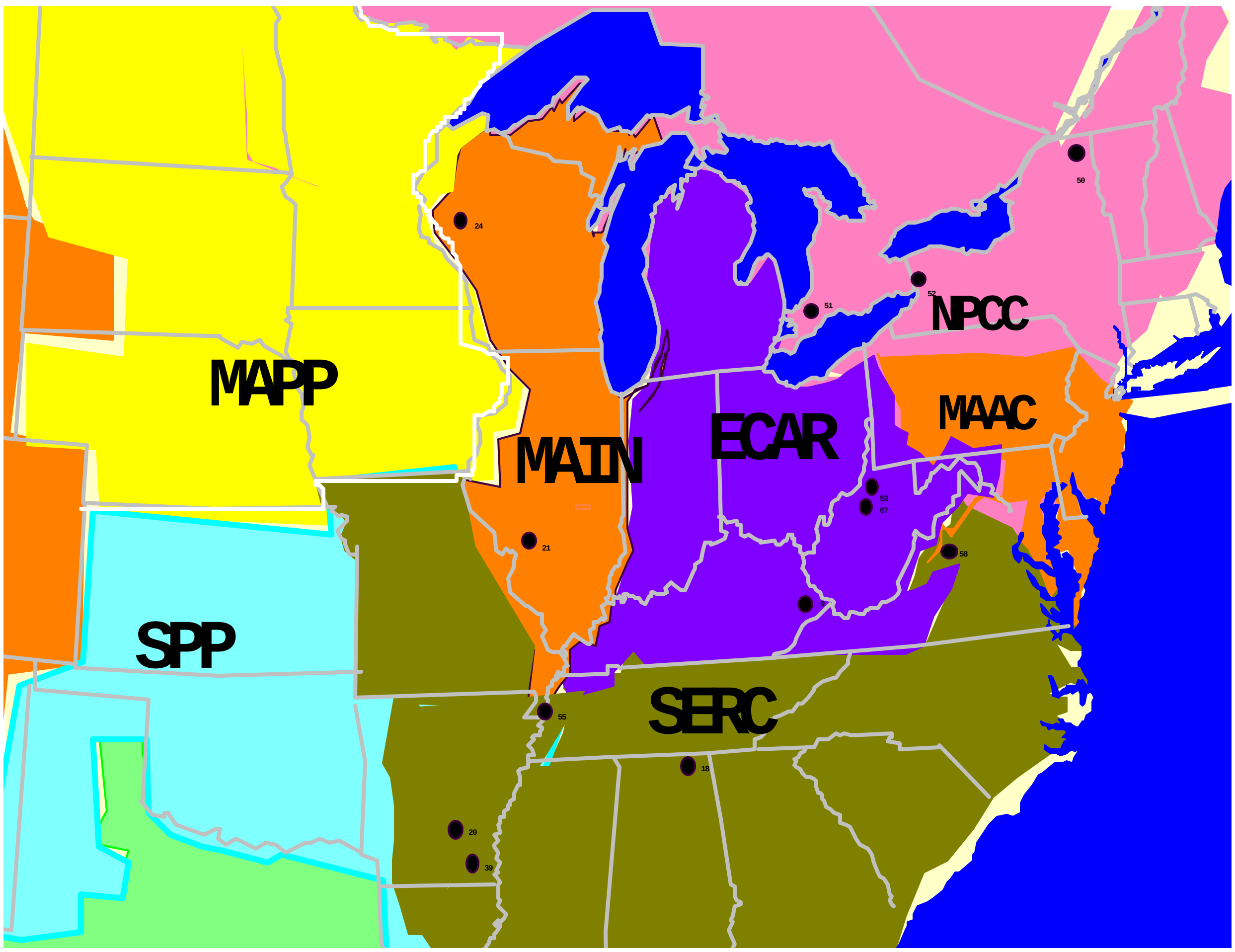
An example of the transmission constraint is the loop flow effect from the Northeast into the Midwest through Canada. Every transaction which moves power from New York or from the Pennsylvania-New Jersey-Maryland (PJM) ISO into Illinois Power in the Midwest has 12.2 percent or 7.7 percent, respectively, of that transaction flowing over the Queenston Flow West (QFW), Ontario, interface.[6] During this week in June 1998, nuclear plant outages in Canada resulted in replacement power from the hydro units at Queenston, which caused a heavy load on the Queenston interface. The increased flows from the Northeast over the Queenston interface to the Midwest caused the overload, and a TLR, on the QFW flowgate. Therefore, any additional transaction flows with effects greater than 5 percent on this flowgate would be curtailed according to NERC TLR procedures. This temporarily cut off the imports from the Northeast and PJM to the Midwest because these transactions exceed the NERC 5-percent threshold on the Queenston interface.

Figure 2-2 shows the location of TLRs with Level 3 or higher that occurred in the summer of 1998. Note the dots in the NPCC region around Lake Erie as these represent the Queenston and IMO-MECS flowgates that were part of the loop flow problem to the Midwest.

[5] Commission Report on Causes of Wholesale Electric Pricing Abnormalities in the Midwest during June 1998.

[6] NERC Transmission Distribution Factor calculator.

Figure 2-2. Location of Level 3 TLRs and above, Summer 1998



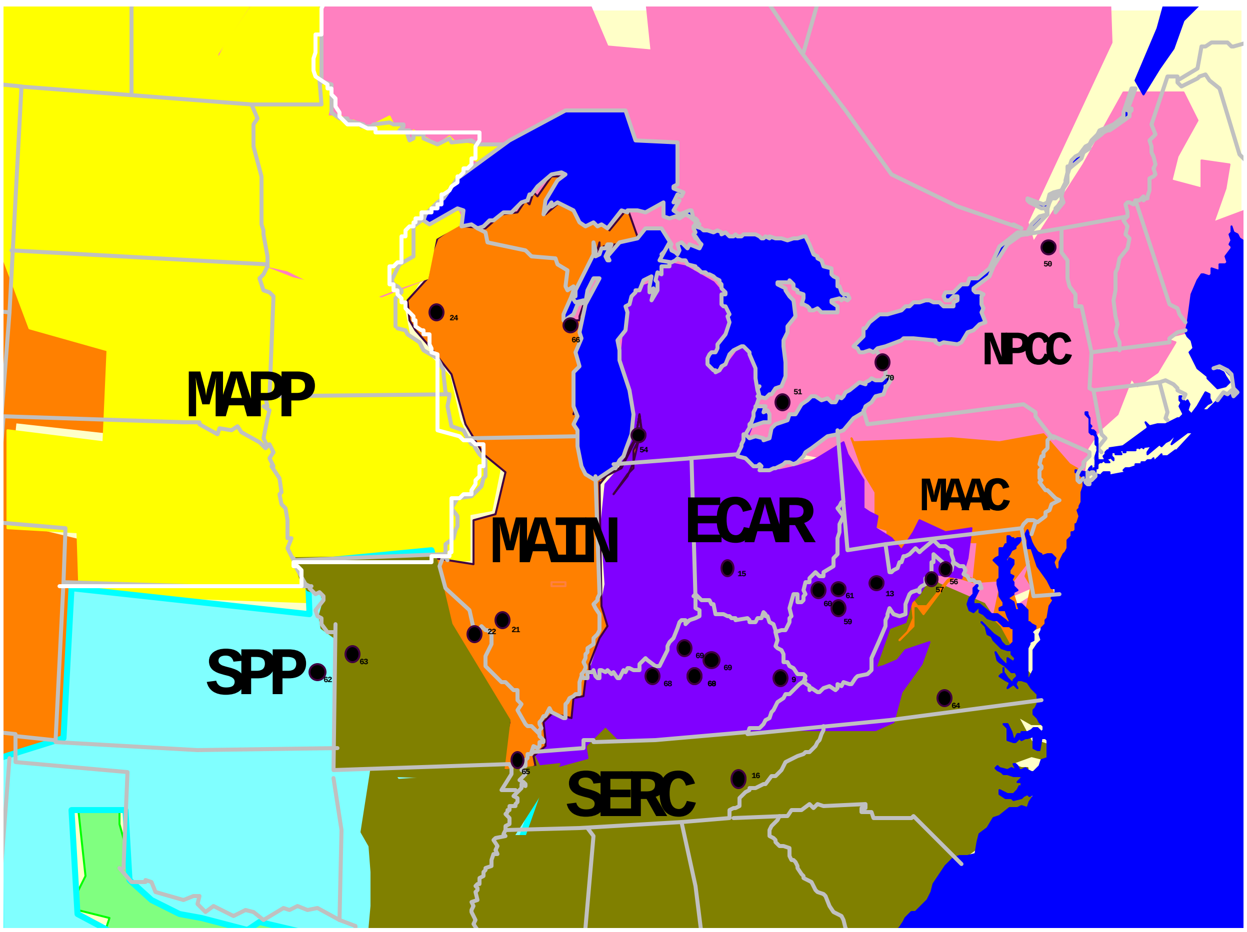
Source: NERC TLR log.

B. Events of 1999

The key events of the summer of 1999 in the Midwest were some brief price spikes in the month of July, an increase in the number of TLR events and an instance where the frequency on the transmission system dipped to the lowest level in history (59.93 Hertz). In addition to transmission constraints caused by thermal overloads, a low voltage problem in central Ohio further reduced the ability to transfer power to the Midwest from the Southeast, which was the only region with spare capacity at that time.

Figure 2-3 shows the location of Level 3 TLRs and higher for the summer of 1999. Note that the dots in the NPCC region, which represent the loop flow problem of 1998 were also present in the summer of 1999. The dot in the center of Ohio represents the central Ohio voltage sag of 1999.

Figure 2-3. Location of Level 3 TLRs and above, Summer 1999



Source: NERC TLR log.

C. Events of the Summer of 2000

Unlike the previous 2 years, this summer saw virtually no price spikes. More generating capacity came on-line and the weather was mild (see below). TLRs, however, climbed to record numbers.

1. Bulk Power Prices

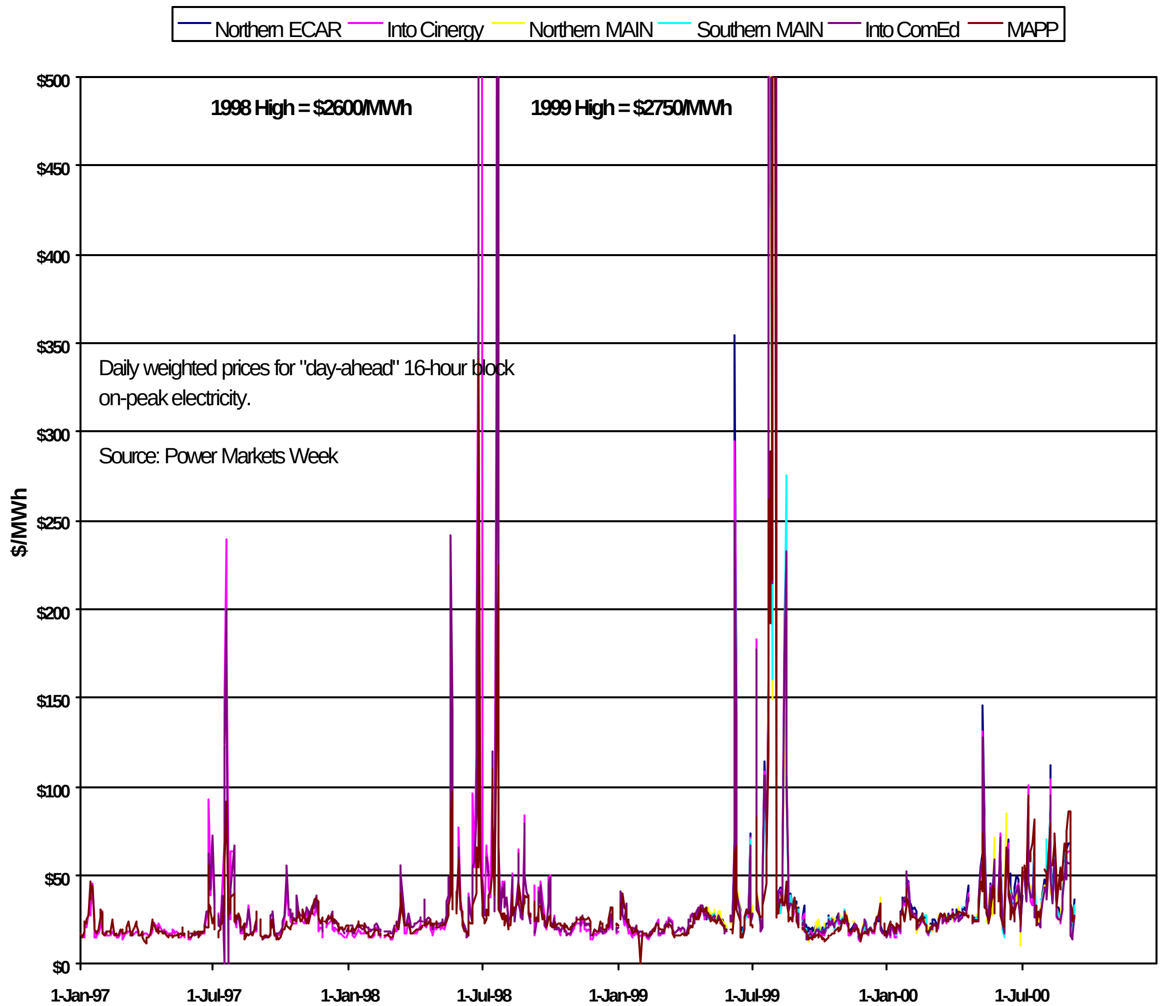
Wholesale prices are determined via bilateral transactions or in the NYMEX spot markets since there is no central clearing house or exchange. This situation will apparently remain since none of the three RTO proposals before the Commission (Midwest, Alliance or SPP) include a central trading exchange. There are, however, 11 hubs in the Midwest region for spot, forward and futures prices. Major trading hubs include Into Cinergy (mid- and southern Indiana and neighboring Cincinnati, Ohio) and Into ComEd (eastern Illinois). The other hubs are Northern ECAR, ECAR, Northern MAIN, CILCO/IP, Into Ameren, Southern MAIN, MAPP, SPP and North SPP. There is some variance in the price data for the 11 hubs because they are compiled by two different publications, *MegaWatt Daily* and *Power Markets Week*, each of which uses a different methodology.

2. Wholesale Prices at the Beginning of the Summer

Figure 2-4 shows the daily price for day-ahead electric power into six Midwestern hubs from January 1997 to August 2000 from *Power Markets Week*. The six hubs are Northern ECAR, Into Cinergy, Northern MAIN, Southern MAIN, Into ComED and MAPP. Note that the vertical axis stops at $500/MWh, effectively truncating the tops of the graphs for the two price spikes in the summers of 1998 and 1999. The values for the peak prices during these two summers are represented by text near the highest visible point of the graph. Without this truncation all other price variation would disappear from the graph. Prices in the summer of 2000, from May 1, 2000, through August 31, 2000, never exceeded $150/MWh. This contrasts with the $2,600/MWh price during the summer of 1998 and $2,750/MWh during the summer of 1999.

The summer of 2000 was relatively calm for Midwest wholesale prices. A number of factors contributed to this situation. As will be shown, the weather was cooler than normal, especially in the upper Midwest. Also, there were no widespread generation outages, as in the 1998 price spike when many nuclear plants were simultaneously down for maintenance. More generation facilities have been built in the Midwest, too. Finally, except for TLRs, there were no major transmission problems like the central Ohio voltage sag or the loop flow problems in 1998 which threatened to isolate the Midwest from the rest of the grid.

Figure 2-4. Daily Price Indices: Midwestern Market Hubs, 1997-2000



3. Ownership in 2000

At this time the majority of transmission is owned by vertically integrated IOUs, cooperatives or municipals as there is no enforced divestiture to an ISO or RTO. Likewise, generation ownership is also highly centralized in one class.

Table 2-7 shows the amount of generation in megawatts by type of ownership, for each region during 2000. IOUs own more than 183,000 MW of generation, or about 66 percent of total capacity. Non-utility generators (NUGs) have the second-highest total, owning about 14 percent of the generation capacity. The other classes of generators share the remaining 20 percent of the market. MAPP, the smallest region for generation, is the most diverse, having representation in every class of ownership, including Canadian, public authorities and federal. Unlike transmission, where ECAR and MAPP have nearly equal miles of high-voltage circuits, ECAR dominates generation. ECAR has more than 120,000

MW, or 44 percent of the Midwest capacity while MAPP has 43,000 MW or 16 percent of capacity.

Recently, there has been a large amount of merger activity, as electric utilities combine with each other or with gas pipeline companies.[7] The electric utility mergers result in a consolidation of generation resources. However, there is no evidence to suggest that the mergers have resulted in any additional concentration of the market or affected prices.

Table 2-7. Generation Capacity by Type of Ownership, 2000
(Megawatts)

Owner Class	ECAR	MAIN	MAPP	SPP	Total
IOU	96,712	35,653	17,677	33,651	183,693
Non-Utility Generators	13,106	22,433	1,491	4,949	41,979
Cooperative	6,022	465	5,507	3,581	15,575
Municipal	4,228	1,621	3,113	6,497	15,459
Canadian	0	0	8,143	0	8,143
Public Authorities	61	0	5,010	0	5,071
Federal	88	0	2,407	1,945	4,440
All Others	324	130	110	591	1,155
Total All Classes	120,541	60,302	43,458	51,214	275,515

Source: RDI Powerdat, August 2000.

Table 2-8 shows the percentage of generation capacity by fuel type in the Midwest for the year 2000. Coal predominates in the Midwest with 61 percent of the capacity and gas is a distant second with 19 percent. In fact, coal has the majority of capacity in three of the four regions with 75 percent in ECAR, 61 percent in MAPP and 51 percent in MAIN. Coal is second to gas only in SPP where coal has 40 percent of capacity and gas 48 percent. Nuclear is a major presence in MAIN with 24 percent of capacity.

Table 2-9 shows the reserve margin for each of the regions for the summer of 2000. The reserve margin is a measure of spare or unused capacity that is available to meet increases in demand and emergency situations. ECAR and MAPP at 14 percent, and SPP at

[7] For example, American Electric Power Service Corporation (AEP) merged with Central and South West Services Company (which is partly located in the SPP control area) and NIPSCO merged with Columbia Gas Transmission Corporation.

12 percent, have comfortable reserve margins, probably due to the cool weather in the summer of 2000. But MAIN, at 5 percent, has a very low reserve margin.

Table 2-8. Generation by Fuel Type, 2000
(Percent)

Region	Coal	Gas	Nuclear	Oil	Other
ECAR	75	11	6	4	4
MAIN	51	17	24	6	3
MAPP	61	9	11	9	11
SPP	40	48	2	3	7
Total	61	19	10	5	5

Source: RDI Powerdat, August 2000.
Note: Percentages may not add to 100 due to rounding.

Table 2-9. Reserve Margin for the Summer of 2000
(Megawatts)

Region	Estimated Peak Demand	Available Capacity	Purchases (Imports)	Sales (Exports)	Reserve Margin
ECAR	93,150	108,651	5,524	5,398	14%
MAIN	48,402	49,736	4,720	3,307	5%
MAPP	33,585	40,334	--	1,200	14%
SPP	37,438	40,164	2,592	--	12%

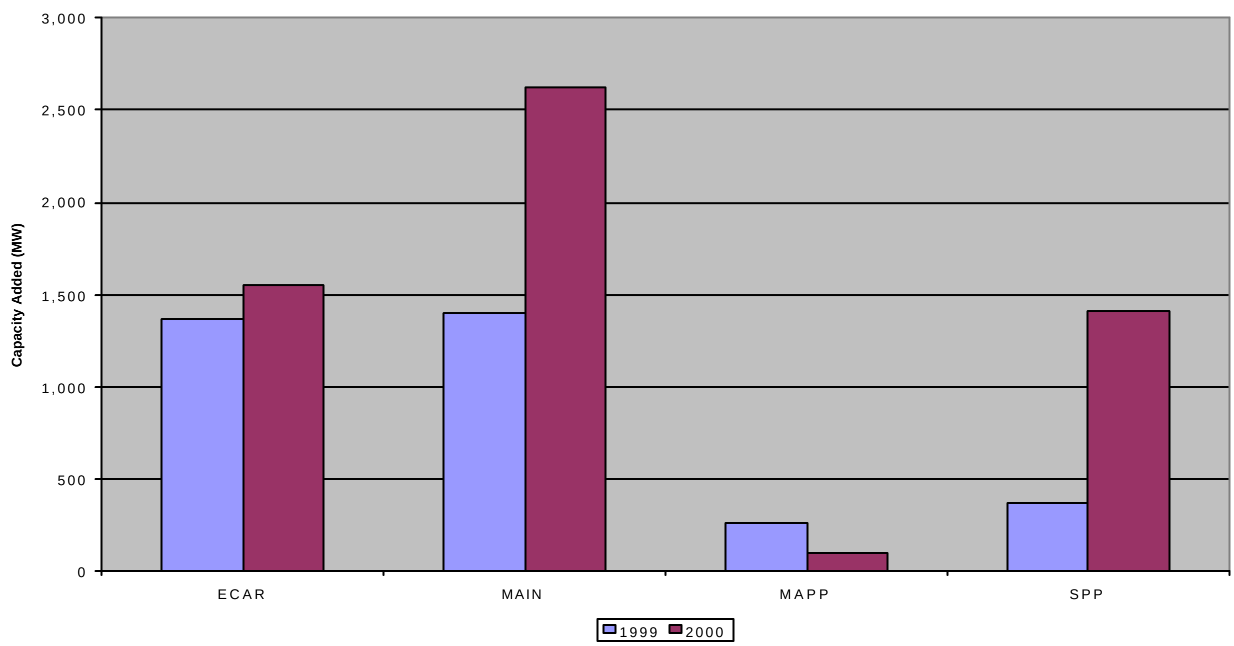
Source: Responses to Staff Data Request.
Note: MAPP Exports and SPP Imports are net figures.

4. Additions to Capacity 2000

As discussed earlier, in the summers of 1998 and 1999, the Midwest experienced price spikes for wholesale bulk power. The midwestern state regulatory agencies did not petition the Commission to institute price caps after these price spikes. Therefore, the Midwest remains a region without area-wide price caps in the wholesale market. Some market participants that provided information to Staff believe that the absence of an area-wide price cap is the single reason that NUG construction has increased in the Midwest.

Figure 2-5 graphically shows the data presented in Table 2-6. The additions to capacity that occurred in 2000 are in red. MAIN had the highest increase of 2,627 MW in 2000 while ECAR and MAPP also had significant expansions of 1,550 MW and 1,415 MW, respectively.

Figure 2-5. Additions to Capacity, 1999 and 2000



Source: RDI Powerdat, August 2000.

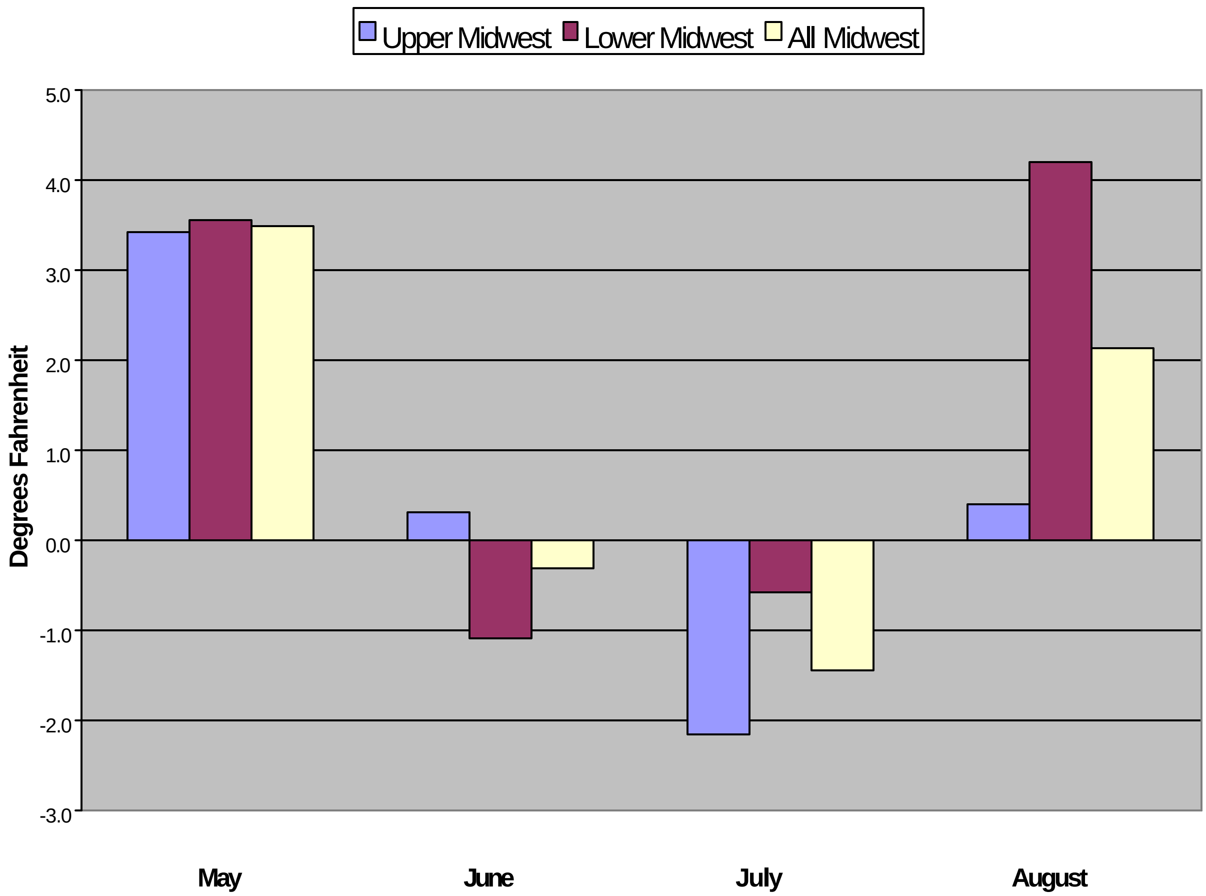
5. Weather in the Summer of 2000

In general, the Midwest had a mild summer compared to the moving average for the past 30 years. Figure 2-6 shows the departure from normal temperatures for the lower, upper and entire Midwest for the summer of 2000. Temperatures across the Midwest were warmer than average in May by about 3 degrees Fahrenheit.

June and July were relatively mild with temperatures typically below normal. In fact, the average temperature in July was more than two degrees cooler for the cities in the upper Midwest (as represented by the average temperature in Chicago, Cleveland, Dayton, Detroit, Milwaukee and Minneapolis).

The weather picture became more complex in August with the upper Midwest following a different pattern than the lower Midwest. The upper Midwest was again close to normal in August. However, the lower Midwest (as represented by the average temperature in Amarillo, Kansas City, Louisville, Oklahoma City and St. Louis) became much warmer than average in August. Many of these lower Midwestern cities are electrically close to regions like central Texas, which set records for high temperatures and lack of rain. Likewise, the southeast United States experienced above average temperatures for all 4 months of the summer of 2000. See the Weather Section for the Southeast region in this Report.

Figure 2-6. Departure from Normal Temperatures, 11 Midwest Cities, Summer of 2000



Source: NOAA, Local Climatological Data—unedited. Http://www.ncdc.noaa.gov.

6. Transmission Loading Relief (TLRs) in 2000

Table 2-10 shows the number of Level 2 TLRs and above, by region for each summer from 1998 to 2000. It tabulates the monthly and yearly totals for each region. The bottom row shows the total for each year and the grand total for all 3 years. There has been an enormous increase in TLRs between the summer of 1999 and the summer of 2000. Specifically, TLRs have grown from 86 during the summer of 1999 to 492 for the summer of 2000, an increase of 472 percent. For this analysis, Staff only counted a TLR at its highest level. When a TLR escalated in Level while it was active, Staff only measured it as one occurrence.

TLRs occurred most frequently in ECAR and MAIN, though the increase in SPP is just as rapid. SPP, however, had a very small base of 14 events for the summer of 1999. Over the last 3 years ECAR had 42 percent of all TLRs (287 of 685) and MAIN had 45 percent of all TLRs (309 of 685). For the summer of 2000 alone, ECAR experienced 45 percent of all TLRs (219 of 492) and MAIN had 40 percent (198 of 492).

Table 2-10. Level 2 TLRs and Above, Summer 1998-2000

Region	1998	1999	2000	Monthly Totals	Region Total
ECAR					
June	13	8	51	**72**	
July	4	24	102	**130**	
August	4	15	66	**85**	
ECAR Total	**21**	**47**	**219**		**287**
MAIN					
June	40	10	31	**81**	
July	25	3	92	**120**	
August	21	12	75	**108**	
MAIN Total	**86**	**25**	**198**		**309**
MAPP					
June	0	0	0	**5**	
July	0	0	12	**12**	
August	0	0	0	**0**	
MAPP Total	**0**	**0**	**12**		**17**
SPP					
June	0	4	27	**31**	
July	0	6	20	**26**	
August	0	4	11	**15**	
SPP Total	**0**	**14**	**58**		**72**
All Regions	**107**	**86**	**492**		**685**

Source: FERC Congestion Management Team Reports compiled from NERC's website.

Figure 2-7 shows a graphical representation of the yearly data in Table 2-10. The enormous increase in total number of TLRs from 1999 to 2000 can be seen.

Figure 2-7. Summer TLR events Level 2 and above, 1998-2000

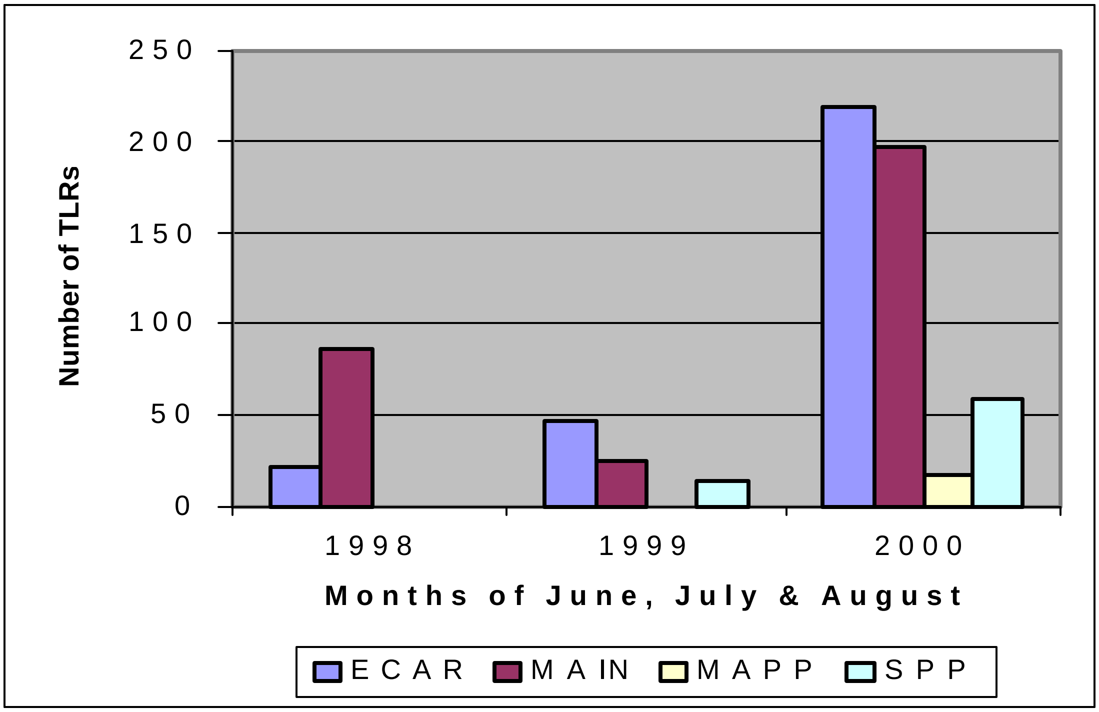


Table 2-11 shows the location of the Midwestern flowgates where TLRs above Level 3 were called most frequently in the summer of 2000. Staff only selected TLRs at Level 3 and above because this is where curtailment of existing transactions begins to occur.[8] Table 2-11 reveals that these TLRs were highly concentrated on a few flowgates. For example, only five flowgates in ECAR accounted for 41 percent (90 of the 219 TLR events), this summer. Likewise, another five flowgates in MAIN accounted for 42 percent (83 of 198 TLR events) of the events there. The direction of flow in the third column of Table 2-11 indicates that power was generally flowing from ECAR and MAIN into SERC when the TLR events happened. Even though the procedures for Level 3 TLRs mandate transaction curtailment to alleviate flowgate congestion, the table shows that the amount of curtailment is not always recorded. For example, 78 of the 191 events in this table do not show any curtailment amount. The total curtailment for the remaining 113 events totals more than 13,144 MW of transactions. The total amount of relief that these curtailments are intended to produce, however, is not posted.

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[8] Some power marketers asserted to Staff that Level 2a and Level 2b TLRs actually "curtail" transactions since the Security Coordinator will not accept any new transactions across the affected flowgate.

Table 2-11. Flowgates Where TLRs above Level 3 Were Called Most Frequently, Summer 2000

Flowgate					Number of TLRs called *(MW curtailed)*			Total	
ID	Name	Direction	SC	CA	Jun	Jul	Aug	TLR	Curtailed
ECAR									
2097	11 Paddys 161 5 Summer 161 1	NE-SW	EMSC	LGEE	0	9 (*)	26 (*)	35	0
2096	11 Blue L 161 20 Blit C 161 1	N-S	EMSC	LGEE	0	9 (*)	24 (*)	33	0
2403	Kanawz-Matt Funk 345/ Baker-Broadford 765	NE-SW	EMSC	AEP	6 *(979)*	3 *(50)*	6 *(100)*	15	1129 MW
2357	01 Wylier 345 / 500TX7/ 01 Wylier 345 / 500TX5	E-W	AP	AP	1 (*)	0	3 (*)	4	0
2404	Kanawz-Matt Funk 345/ Broadford-Jferry 765	NW-SE	EMSC	AEP	1 (*)	0	2 (*)	3	0
Total ECAR					**8**	**21**	**61**	**90**	**1129 MW**
MAIN									
3413	Coffn-Roxfd IP for Newtn-Mt Vrnon	NW-SE	MAIN	IP	0	12 *(1059)*	18 *(3737)*	30	4796 MW
3102	BlandFranks 345 KV	NW-SE	MAIN	AMRN	1 *(441)*	6 *(705)*	18 *(1896)*	25	3042 MW
10204	McCred-Overton345 for Bland-Franks	E-W	MAIN	AMR N	0	0	13 *(1078)*	13	1078 MW
3117	Blands-Franks + Rush-St Francois	NW-SE	MAIN	AMR N	0	1 (*)	8 *(300)*	9	300 MW
3144	Rush-St Francois + Blands-Franks	NW-SE	MAIN	AMR N	4 *(150)*	2 *(291)*	2 *(263)*	8	704 MW
Total MAIN					**5**	**21**	**59**	**85**	**9920MW**

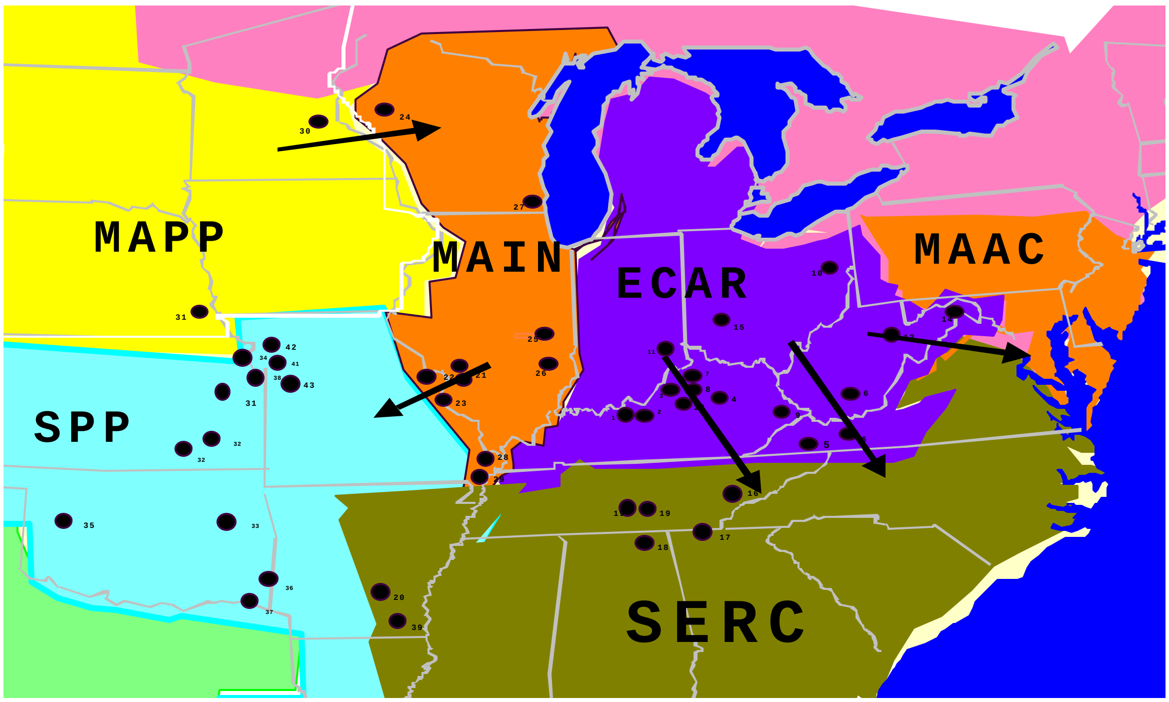
Table 2-11 (continued) Flowgates Where TLRs above Level 3 Were Called Most Frequently, Summer 2000

Flowgate ID	Name	Direction	SC	CA	Number of TLRs called *(MW curtailed)* Jun	Jul	Aug	TLR	Total Curtailed
MAPP									
6009	Cooper_s	E-W	MAPP	NPPD	2 *(587)*	3 *(309)*	1 *(127)*	6	1023 MW
6012	Pri-Byn	NW-SE	MAPP	NSP	1 (*)	1 (179)	0	2	179 MW
Total MAPP					**3**	**4**	**1**	**8**	**1202 MW**
SPP									
5005	CatXfrCatXfr	S-N	SWPP	GRDA	2 *(165)*	0	0	2	165 MW
5015	ElpFarWicWdr	NE-SW	SWPP	WR	2 *(226)*	0	0	2	226 MW
5050	StjLakIatStr	NW-SE	SWPP	KCPL	0	0	2 *(422)*	2	422 MW
3108	Overton-Sibley 345 KV	SE-NW	SWPP	MPS	1 (*)	0	0	1	
5045	PhiSphSumEmc	S-N	SWPP	WR	1 *(80)*	0	0	1	80 MW
Total SPP					**6**	**0**	**2**	**8**	**893 MW**
Total all 4 Midwest Regions					**22**	**46**	**123**	**191**	**13144 MW**

Source: Oasis Site at SPP
(*) no curtailment listed

Figure 2-8 shows the location of the transmission flow constraints (dots), and the direction of flows (the arrows) during July 2000 in the Midwest. The dots indicate significant TLR events at flowgates and are generally clustered on the southern and eastern borders of ECAR, the southwestern borders of MAIN and around Kansas City in SPP.

Figure 2-8. Transmission Flow Constraints and TLR Locations, July 2000



Source: NERC TLR log.

4. Regulatory and Institutional Environment

A. Overview

In addition to the federal regulatory scheme discussed in the West Report, each of the 17 states that lie entirely or mostly in the four major Midwest NERC regions (ECAR, MAIN, MAPP and SPP) have regulatory agencies to regulate retail transmission service. These state agencies are: the Arkansas Public Service Commission; the Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the Iowa Utilities Board; the Kansas Corporation Commission; the Kentucky Public Service Commission; the Louisiana Public Service Commission; the Michigan Public Service Commission; the Minnesota Public Utilities Commission; the Missouri Public Service Commission; the Nebraska Public Service Commission; the North Dakota Public Service Commission; the Ohio Public Utilities Commission; the Oklahoma Corporation Commission; the South Dakota Public Utilities Commission; the West Virginia Public Service Commission and the Wisconsin Public Service Commission.

State agencies also regulate the siting for constructing transmission facilities and, in some instances discussed below, the siting for generation facilities.[9] As part of or in lieu of siting requirements, states require environmental permits to be obtained for the construction of transmission or generation facilities. In addition to state regulation, municipalities have zoning ordinances that would apply to the construction of such facilities.

B. Regulation of Transmission Service

The Commission regulates wholesale transmission services such as the terms and conditions, the priorities, and the information that must be publicly posted regarding such services under the open access rules established in Order Nos. 888, et seq., and Order Nos. 889, et seq. The Commission, however, has permitted NERC to continue to have the responsibility for setting standards for operating the transmission grid. This includes allowing NERC to set the standards and procedures for calling TLRs. However, NERC's guidelines and procedures for maintaining system reliability in control areas are voluntary. As a result, the NERC guidelines and procedures are not enforced by remedies such as penalties or refunds.

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[9] In Ohio, transmission and generation facility siting is regulated by the Ohio Power Siting Board, not the Ohio Public Utilities Commission.

The Commission has required utilities to place certain of the NERC standards and procedures into their respective Open Access Transmission Tariffs (OATTs). By doing so, the Commission has the power to enforce provisions in the OATT under the Federal Power Act. In practice, however, the Commission has generally deferred to NERC on transmission reliability questions, including the propriety of TLRs called by utilities and/or control areas. A notable exception, discussed in Section 5, involved the Commission approving a provision in the ECAR tariff providing for penalties for improperly pulling power from its transmission grid.

The problems associated with the current regulatory scheme for transmission system reliability issues are discussed in Section 5.

C. RTOs

Currently, no regional transmission organizations (RTOs) control transmission and reliability activities in the Midwest. However, there are three RTO proposals before the Commission to operate in the Midwest: the Midwest ISO; the Alliance RTO; and the Southwest Power Pool (SPP) RTO.[10] Membership in the proposed RTOs is currently very fluid. For example, on September 20, 2000, Illinois Power Company (Illinois Power) announced that it was withdrawing from the Midwest ISO and intends to join the Alliance RTO, pending regulatory approval.

In late 1995, many of the largest transmission utilities in the Midwest began discussions on creating a single independent system operator to operate the regional grids. Some transmission providers joined in the discussions because certain proposed state laws required joining an independent system operator as a prerequisite for participating in a retail access program. In 1996, the preliminary discussions led to the signing of a Memorandum of Understanding and negotiations proceeded throughout that year and 1997. However, in December 1997, Indianapolis Power and Light, First Energy, Detroit Edison and Consumers Power left the group. The latter three transmission providers are currently members of the proposed Alliance RTO. The remaining members of the Midwest ISO

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[10] The Midwest ISO and Alliance RTO initial filings were made prior to the Order No. 2000 requirements for making RTO filings. Both entities are required to make new filings, pursuant to Order No. 2000, by January 15, 2001. The current Southwest Power Pool filing was made pursuant to Order No. 2000.

recruited new signatories to the agreement and filed a proposal with the Commission in 1998.[11]

As of October 26, 2000, the proposed Midwest ISO was composed of 19 transmission providers located primarily in the MAPP or MAIN service areas. The 19 participants in the Midwest ISO were: Alliant Energy; Ameren Companies; American Transmission Company, LLC.; Central Illinois Light Co.; Cinergy Services, Inc.; Commonwealth Edison Company; Hoosier Energy Rural Electric Cooperative; Illinois Power Corporation (which, as noted above, has announced its intention to withdraw from the Midwest ISO); LG&E Energy Companies; Madison Gas and Electric; Xcel Energy (formerly Northern States Power); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas and Electric Company (SIGECO); Utilicorp United; Wabash Valley Power Association, Inc.; Wisconsin Electric Power Company; and WPS Resources Corporation.

Pursuant to the Midwest ISO Agreement, the Midwest ISO will be organized as a non-stock, not-for-profit corporation.[12] The participating transmission owners will transfer to the Midwest ISO functional control over all network transmission facilities above 100 kV and all network transformers whose two highest voltages exceed 100 kV.[13]

The transmission owners will retain ownership of their transmission facilities, and will physically operate and maintain these facilities, subject to the Midwest ISO's direction.[14] Under the Midwest ISO Agreement, the transmission owners who are currently control area operators will continue to operate their control areas for local generation control and economic dispatch purposes.[15] However, the transmission owners will follow the directives of the ISO for redispatching generation, curtailing load, and providing reactive supply, voltage control or other ancillary services.[16] Under the provisions of Appendix E of the Midwest ISO Operating Agreement, the Midwest ISO's duties will include calculating available transmission capability (ATC), maintaining OASIS

11The Commission initially authorized the establishment of the Midwest ISO on September 16, 1998. Midwest Independent Transmission System Operator, Inc., *et al.*, 84 FERC ¶ 61,231 (1998).

12Midwest ISO Agreement at 5.

13*Id*. at 3.

14*Id*. at 8, 52-55.

15*Id*., Appendix E at 9.

16*Id*. at 52.

information, receiving, approving, scheduling and confirming transmission service requests and providing or arranging for ancillary services under the tariff. The ISO will also function as the system security coordinator for its transmission-owning members.[17] The Midwest ISO will not operate any centralized power markets; participants will rely on bilateral contracts for energy.

As of October 26, 2000, the proposed Alliance RTO consists of four Midwest utilities, American Electric Power Service Corporation, Consumers Energy Company, Detroit Edison Company and First Energy Corporation, and one Southeast utility, Virginia Electric and Power Company. [18] The proposal includes the midwestern states of Michigan, Indiana, Ohio, Kentucky and West Virginia.[19] On December 20, 1999, the Commission conditionally authorized formation of the RTO.[20] On September 15, 2000, the Alliance Companies made a compliance filing with the Commission proposing to create the RTO in the form of a for-profit Transco. The Transco will be formed as a limited liability company that will be controlled and managed by its managing member, an independent entity with no affiliation as a market participant.[21] According to the Alliance Companies' filing, the Alliance RTO will own and operate transmission facilities that are divested to it by members of the Alliance Transco. The RTO would also operate transmission facilities of non-divesting transmission owners that have entered into an operation agreement with Alliance Transco for operation of those facilities.[22] As with the proposed Midwest ISO, the pre-existing control areas will continue to exist under the Alliance RTO.

On October 13, 2000, SPP filed an RTO proposal with the Commission (Docket No. RT01-34-000). This filing replaces an earlier RTO proposal that the Commission rejected without prejudice on May 17, 2000. [23] On October 16, 2000, Entergy Services Inc. made a filing with the Commission proposing to create an independent, for-profit Transco to

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17 *Id*.

18 In separate October 16, 2000 filings with the Commission, Northern Indiana Public Service Company and Dayton Power & Light Company stated that they have decided to pursue membership in the Alliance RTO.

19 First Energy also has areas of western Pennsylvania in its service territory.

20 Alliance Companies, *et al*., 89 FERC ¶ 61,298 (1999), *reh'g pending*.

21 Alliance Companies' September 15, 2000 filing at 3.

22 *Id*.

23 Southwest Power Pool, Inc., 91 FERC ¶ 61,136 (2000).

operate under the oversight, and within the umbrella of, the proposed SPP RTO (Docket No. RT01-75-000).

D. Retail Access

Although restructuring activities in midwestern states have been ongoing, only a few states had retail access programs in place by the summer of 2000. These include Michigan, which mandated an immediate 5-percent rate reduction for some customers as of June 2000 and phased in retail access beginning in 1999, and Maryland (the western portion of which lies in ECAR) and Illinois, which were phasing in retail access during the year. In Pennsylvania (the western portion of which lies in ECAR), retail access to competitive electricity suppliers was available for all customers by January 2000, stranded cost recovery and rate reductions have been approved on a company-by-company basis. Arkansas (some of which is in SPP) required utilities to file functionally unbundled retail rates by January 2000. West Virginia has approved a retail choice program, which, depending on the course of certain enabling legislation, will take effect sometime in 2001. The program contains rate caps on generation for 4 to 13 years, depending on certain factors. Finally, by statute, Oklahoma must implement retail choice by July 1, 2002, however, enabling legislation has not passed yet.

E. Regulatory Requirements for Constructing Generation Facilities

There appear to be few significant regulatory barriers to entry for generation siting in the Midwest. While it is difficult to summarize a large geographic area with a wide variance in regulations, it is possible to make some general observations. Staff surveyed the state regulatory entities in the 17 states that lie entirely or mostly in the major Midwest NERC regions. The results of this survey are summarized in Table 2-12 below:

Table 2-12. Summary of Midwestern PUC Entry Requirements

State	Generation Siting Requirements	Retail Choice	Rate Freeze[24]	Price Caps
Arkansas	Removed siting requirements as of Jan 1, 2002. Environmental requirements still apply.	Phasing in. Mostly effective in 2002	Frozen for 1 year. starting in 2002, 3 years if stranded costs are claimed	
Illinois	Jurisdictional entities need a state air permit. Non- jurisdictional meet only local ordinances.	Phasing in	Bundled retail rates frozen until 2005	
Indiana	Typical certificate takes 2-3 months unless there is a local controversy.	Yes		No
Iowa	Process takes 2-3 months.	No		No
Kansas	Repealed except for nuclear plants.	No		No
Kentucky	Permit process typically takes 6 months.	No		No
Louisiana	Separate application process for generation & co-gen facilities; takes approximately 1 year.	No		No
Michigan	Environmental and local zoning permits only.	Phased in beginning 1999	5% rate cut for certain customer classes	
Minnesota	Permit process typically takes 6 to (if protests) 18 months.	No		No
Missouri	Certificate of public convenience for areas not covered by previous permits.	No		No
Nebraska	Certificate of public need, air and water permits, typically takes about 2 months.	No		No
North Dakota	Certificate for facilities 50 MW and above. Application process takes up to 1 year.	No		No
Ohio	Typical permit takes 7 to 9 months.	Begins Jan 1, 2001	5% rate reduction for residential customers	

[24] Denotes freeze on all IOUs, not a rate freeze agreed to by individual companies.

State	Generation Siting Requirements	Retail Choice	Rate Freeze[24]	Price Caps
Oklahoma	No siting requirements other than environmental and zoning permits, takes about 6-9 months.	Statute passed, awaiting enabling legislation		No
South Dakota	Requirements for units 100 MW and above. Typical time: 6 months.	No		No
West Virginia	Siting requirements take 2 -3 months. Separate environmental review may be required.	Approved. Starts in 2001		Generation rate caps for 4-13 years.
Wisconsin	Permit required for all units >100MW and some < 100 MW (depending on cost). Approx. 6 mos. to process.	No		No

The survey revealed a wide spectrum of regulatory philosophies ranging from no formal siting requirements (e.g., Michigan, Illinois) to detailed certification requirements (e.g., Ohio, Wisconsin). All of the states required some form of environmental permits. In addition, local zoning ordinances apply.

The survey also asked the state agencies about the average time period to complete the regulatory requirements for construction of generation facilities. Five states (Arkansas, Illinois, Kansas, Michigan and Oklahoma) have either no siting requirements, have siting requirements only for regulated utilities, or have recently repealed siting requirements (although environmental and zoning requirements remain).[25] One state, Missouri, does not have siting requirements for generation projects by regulated utilities that will be constructed within territory already allocated to it in a previous permit.[26] Seven states (Indiana, Iowa, Kentucky, Nebraska, South Dakota, West Virginia and Wisconsin) indicated that the typical permitting process takes between 2 and 6 months. Four states

[25] However, Oklahoma reported that it takes an average of 6 to 9 months to obtain environmental permits.

[26] Staff was told that there have been no generation siting applications in Missouri for at least 10 years, although several generation facilities, ranging from 250 MW to 1,000 MW, have either recently been constructed or are proposed to be constructed within the state by regulated utilities under preexisting permits.

(Louisiana, Minnesota, North Dakota and Ohio) responded that the typical process would take longer than 6 months. The longest period reported was 18 months.[27]

Our survey revealed a marked increase in several Midwest states during the last 2 years in both the number and amount of generation construction and applications for generation construction. The states that have had the most activity in proposals for, and construction of, generation facilities include some with no siting requirements (e.g., Illinois, Michigan) and some with detailed siting requirements (e.g., Ohio). The construction activity has been by utilities and non-utility generators (NUGs). Investments included capacity upgrades and capacity expansions on existing units as well as new base- and peak-load generation.

F. Transmission Construction

As with generation facilities, state and municipal regulatory entities have jurisdiction over siting requirements for transmission facilities. However, the regulatory permitting process for transmission siting can be long and arduous. Because jurisdictional utilities are usually the entities that seek to construct transmission facilities, state siting requirements are usually applicable to their construction (e.g., Illinois). In addition, transmission facilities generally require more zoning and environmental permits than generation facilities because they cover a larger area, spanning several municipalities. There are also more affected landowners that may protest a permit application.

There has been minimal investment in or change to the transmission system in the Midwest. In Illinois, the only recent major transmission facility addition was a ComEd Double Circuit 345 kV line around the Chicago to Wisconsin bottleneck. In the past three years, Ohio has had more than 20 applications for generation facilities, but only three for transmission facilities. The issue of the lack of investment in transmission facilities is discussed more fully in Section 5.

[27] In response to Staff data requests, one NUG alleged that the permitting process in Indiana was slow because intervener groups are attempting to burden new merchant plants with liability for compensating consumers for any cost increases perceived to be caused by transitions to a competitive/merchant environment. Another NUG stated that it elected not to construct a plant in Ohio because the siting process was long and cumbersome.

5. Market Issues in the Midwest

As discussed earlier, the Midwest region is dominated by vertically integrated transmission providers, each having control over their own transmission and generation functions, serving their own native load. As such, they have weak economic incentives to provide access to transmission service to third-parties on a completely comparable basis and have incentives to favor their own generation. Moreover, the 61 control areas in the region utilize varying procedures relating to transmission service, including calling TLRs, calculating available transmission capacity (ATC) and processing interconnection requests. Thus, market participants seeking transmission services must keep track of, and deal with, a plethora of information in order to make energy deals, submit reservations and provide schedules for service.

During this investigation, Staff received many complaints from market participants alleging barriers to transmission access, including TLR curtailments, lack of standardized protocols for providing information, particularly ATC, handling interconnection requests, and discriminatory conduct. We have been able to substantiate some of these complaints. But certain key data to analyze some of the issues, such as the causes of the TLRs, either are unavailable at this time from the NERC regions and/or key transmission providers (e.g., coincident peak load data for the summer of 2000) or are not maintained at all (e.g., import/export data). The fact that these data were not readily available prevents an assessment of whether markets are functioning efficiently.

Because of the inability to obtain critical information concerning general problems, such as the causes of TLRs, we are unable to definitively determine whether transmission access problems are systemic and wide-spread in the Midwest or whether the problems represent a collection of isolated incidents. Because of this lack of clarity, we were also unable to determine whether the appropriate regulatory response to these problems should be more aggressive enforcement of existing rules (if the problems are isolated incidents) or whether the rules need to be adjusted (if the problem is systemic). The lack of this information, in itself, creates a market inefficiency, because neither market participants nor regulators can fully analyze market conditions in real time in order to make decisions on what actions to take.

As discussed in this report, at the very least, the volume and variety of complaints by market participants indicate a lack of confidence in the bulk power market in the Midwest. The perceived lack of clarity in the current rules and procedures, as well as the allegations of specific instances of discrimination, harms the liquidity of the market by hindering the ability of market participants to rely on transmission access. As a result, market participants seem to have become risk-averse, eschewing long-term deals for short-term transactions.

The Midwest RTO proposals before the Commission may mitigate some of the problems and inefficiencies alleged, however, the fact that all three proposals would, at least initially, retain existing control areas may make it less likely that the operation of those RTOs as proposed would resolve these issues completely. By maintaining existing control areas, the incentives for favoring generation sales, including native load, would continue to exist unless the RTO exercises complete autonomy over transmission control and security coordinator functions, such as calling TLRs, calculating ATC and handling interconnection requests and system impact studies.

The specific transmission issues in the Midwest are discussed below.

A. TLRs

1. Effect of TLRs

The dramatic 472 percent increase in TLRs between the summer of 1999 and the summer of 2000 poses a definite problem for transmission access in the Midwest. The massive number of TLRs in the summer of 2000 has not caused any system-wide price spikes or any area-wide supply disruptions, but they do have a negative effect on the market. TLRs inhibit optimal functioning of the transmission system, and thereby the market, because load is not served by the least cost supplier. However, quantifying the effect of this is difficult. A lower bound estimate would be the cost to re-dispatch the 13,144 MW curtailed at the five most frequently interrupted flow gates during the summer of 2000 (see Table 2-11, in Section 3).

The TLR procedure is an inefficient instrument to use in mitigating transmission constraints. When an overload occurs on a flowgate, the Security Coordinator orders curtailment by fiat, and scarce resources are allocated by command and control instead of the market. TLR curtailment does not allow the transmission customers who value the scarce resource the most (i.e., the overloaded flowgate) to compensate others who might voluntarily cut back their transactions. Instead, all transactions that have 5 percent or more of their flow on that affected flowgate will be curtailed.

Another inefficiency can occur because the Security Coordinator can not always precisely identify which transactions are affecting the overloaded flowgate. During certain TLR events, the NERC Interchange Distribution Calculator (IDC) calculates the transaction factors for curtailments based upon control area-to-control area pairs. This calculation can result in potentially inappropriate transaction curtailments or increased loading on the affected flowgate. NERC has recognized this problem and formed the IDC Granularity Task Force to address it.

The increased incidences of TLRs appear to have eroded confidence in the Midwest transmission market. Some public power market participants indicated to Staff that the large number of TLRs harmed the liquidity of the market by stifling long-term transactions (2-3 years). They alleged that marketers are less willing to enter into multi-year contracts for fear that they will be unable to fulfill their commitments because of the TLRs.

An RTO could mitigate this problem if it consolidated all of the transmission providers into one control area and/or the RTO had the sole responsibility for calling TLRs for all of its members. Otherwise, each control area would continue to set its own procedures for determining whether to call a TLR and the information on ATC and CBM provided to the RTO would still come from individual control areas.

2. What Has Caused TLRs to Increase So Dramatically?

Staff was unable to obtain key data for this report that would have assisted us in determining the definitive reasons for the dramatic increase in TLRs during the summer of 2000. Staff attempted to obtain data from ECAR, MAIN, MAPP and SPP on the exports and imports by region for 1999 and 2000, as well as the coincident and current peak load estimates for each region. We were informed that import and export data were not available and that the peak load data for 2000 would not be available for several months. In addition, we attempted to obtain from several transmission providers system- wide snapshots for days when TLRs were called, but were informed that they did not keep snapshot data. As a result, the discussion below is somewhat speculative, based on facts that Staff were able to obtain during the period of the investigation. As discussed infra, the unavailability of this information is itself an inefficiency of the market because it undermines the ability to analyze the fluctuations of the market.

Prolonged above average temperatures are usually a major reason for TLRs because there is increased demand on the grid. However, there were more TLRs in the Midwest in July 2000 (42% of the total for the summer of 2000) than in June (28%) or August (30%), although August was the hottest of the three months. Nonetheless, weather may have been a factor in the increased TLRs because of prolonged above-average temperatures in the regions adjacent to the Midwest. For example, the adjacent SERC region was hotter than average for May through August 2000.

While the Midwest experienced a mild summer, it is bordered by two NERC regions (ERCOT and SERC) which experienced hotter than normal weather conditions. One factor contributing to the high number of TLRs was that electric power was trying to flow from the Midwest to these warmer regions. A contributing factor may be that cheaper, coal fired plants in the Midwest were trying to export electricity to SERC where it was hotter and the predominant generation was more expensive gas fired generation. While, as discussed above, Staff was unable to obtain export data to test this hypothesis, it is supported by the clustering of TLR events on the southern border of the Midwest for July 2000 and the general direction of power flows during those TLRs (see Figure 2-8, in Section 3). The table shows that most of the Midwest TLRs occurred in Kentucky, southern Illinois, Missouri, Oklahoma and Arkansas.

Some market participants have suggested that the increased incidents of TLRs, in many instances, are the result of noncompetitive behavior by vertically integrated transmission providers to benefit their affiliates.[28] Because the Security Coordinator, who calls TLRs, often works for an integrated IOU, there exists a mixed incentive to enforce reliability on the grid and to maximize profit for the IOU. As discussed later, there has been no concerted regulatory effort to date to police the implementation of TLRs to ensure that they are utilized properly and in a non-discriminatory fashion.

Whatever the exact reason for the dramatic increase in TLRs in the summer of 2000, as discussed earlier, the large number of TLR curtailments inhibits the Midwest market by preventing load from reaching its destination and by discouraging public power market participants from entering into long-term transactions. These problems will continue until TLRs become less frequent.

B. Inadequate Regulation to Prevent Abuses of the Transmission Grid

Several market participants have argued to Staff that the current regulatory environment has not kept up with the new challenges of the Open Access era, in which there are economic incentives for transmission providers to misuse the transmission grid to benefit their own load. As discussed in Section 4, the Commission has deferred to NERC the responsibility for setting standards for operating the transmission grid, including the standards and procedures for calling TLRs.

NERC's guidelines and procedures for maintaining system reliability in control areas are voluntary. Thus, the NERC guidelines and procedures are not enforced by remedies such as penalties or refunds. Although the Commission has required utilities to place certain of the NERC standards and procedures into their respective OATTs, the Commission has generally deferred to NERC on transmission reliability questions, including the propriety of TLRs called by transmission providers and Security

28 "Transmission Markets, Stretching the Rules for Fun and Profit," Narasimha Rao and Richard D. Tabors, TCA Working Paper No. 327-0400, April 2000.

Coordinators. As a result, in the rare instance that regulatory action has been taken, it has been reactive rather than pro-active, with only prospective impact in localized areas.

For example, during a price spike in July 1999, Cinergy, a Midwest utility, declared that a force majeure situation prevented it from performing its contractual obligations under power supply contracts. However, at the same time, Cinergy pulled more than 1,500 MW of power from the grid that it did not own to service part of its obligations (sometimes known as "leaning on the system"). In December 1999, ECAR sent a letter of reprimand to Cinergy for intentionally using the Eastern Interconnection as a supply resource during July 22, 23 and 29, 1999, thereby decreasing the frequency of the entire Interconnection and jeopardizing its reliability. However, there was no regulatory mechanism in place to remedy the violation or to effectively deter such conduct in the future. On May 31, 2000, the Commission approved a settlement adding a provision to ECAR's tariff that requires a party that draws power from the grid to compensate the parties that made up the shortfall under certain circumstances. However, this is a localized prospective response, limited to ECAR, and does not address similar actions in other NERC regions.

While a Cinergy-type situation is a cause for concern, market participants in the Midwest appear to be more concerned with setting and enforcing uniform standards for calling TLRs, and providing an effective remedial mechanism when TLRs are improperly implemented. TLRs are not called uniformly and consistently over this big physical area (four regions, 61 control areas with six Security Coordinators). For example, a Level 5 TLR in SPP on May 12, and again on May 16, 2000, did not curtail network services or reduce native load, it only curtailed firm point-to-point transactions. NERC procedures call for a pro rata reduction of firm point-to-point, network services and native load during a Level 5 TLR event.

The lack of uniform standards for implementing TLRs creates an uncertainty for public power market participants as to the likelihood that their transmission schedules will be curtailed. Moreover, Staff was unable to analyze, because of inadequate existing information, whether TLRs have been implemented to advantage a transmission provider's generation resources. The lack of adequate remedial measures if this occurs appears to have created an atmosphere of skepticism among public power market participants, who question whether transmission providers have any incentive not to use TLRs to favor their own generation.

C. Lack of Posted Information on TLRs and Curtailments

Another area of uncertainty for market participants relating to TLRs is the lack of information available on OASIS, particularly real-time information, concerning TLRs. Most OASIS nodes do not show curtailment amounts for each TLR. Those nodes that do list curtailment amounts do not show it for every TLR event. For instance, the top five TLR events in each of the four NERC regions for the summer of 2000 consist of 191 individual TLR events. However, 78 of those instances do not show any curtailment amount which would allow market participants to monitor if more curtailments are occurring than necessary (see Table 2-11).

No single OASIS site for the Midwest lists all the TLR curtailment information, although SPP is the best site for this information. The MAIN OASIS site sometimes lists a few TLR curtailment amounts, but not all. When the two sites list the same TLR event the curtailment amounts are inconsistent.

The NERC Web site does not show all TLR events or complete information on each TLR event that it does list. For example, the NERC real time database (TLR Active Log) lists TLR events that the monthly summaries (from the NERC TLR Log) omit. Likewise, the monthly summaries contain TLR events and information that the real time database omits. One market participant reported that a transmission provider denied a scheduling request because the transmission provider had called a TLR. The respondent could not find any evidence that a TLR had been called either on the NERC web site or the transmission provider's OASIS site. Another market participant provided an audio tape to Staff containing discussions with a transmission provider and other affected parties concerning a TLR that had been improperly implemented, causing the market participant a substantial financial loss.

When the software tools are used on a control area-to-control area basis, they may not correctly recognize and quantify all sources on the overloaded flowgate. When this happens the curtailment process becomes more inefficient as incorrectly identified transactions are curtailed. Also, correctly identified transactions may be curtailed by more than necessary.

While Staff received few data alleging specific economic losses from TLRs, at best, the lack of real-time information as to when TLRs are occurring reinforces the current insecurity and uncertainty of public power and other market participants which they expressed to Staff during this investigation. The consequence of this is a reluctance to rely on long-term transactions, thereby harming the liquidity of the market.

D. Lack of Standardized Protocols

In addition to the lack of standardized information on curtailments discussed above, another area of market uncertainty is the lack of protocols for calculating Available Transmission Capacity (ATC), Capacity Benefit Margin (CBM) and handling transmission requests and scheduling. The lack of standardized protocols results in inadequate information for potential requesters of service. As a result, it is difficult to efficiently market electric power over an area as wide as the Midwest. The Midwest currently is a balkanized region in which 61 control areas do not have uniform procedures for calculating ATC and CBM, processing transmission requests and scheduling, thereby creating uncertainty in the marketplace.

The problems of non-standardized protocols, discussed below, are not likely to be completely solved by RTOs if the RTOs retain multiple control areas and procedures. For example, it is not enough for an RTO to calculate ATC for its members if the members provide the data used by the RTO to calculate ATC. Otherwise, given that the control areas contain generation units of the transmission providers, the incentive for those providers to favor generation will continue.

1. Uncertainty in ATC and CBM Calculations

There are no consistent rules for calculating and posting ATC and CBM. For instance, SPP posts ATC by flowgate while the other regions post ATC by control areas. Transmission providers have wide latitude to use various methodologies to calculate ATC. This variance comes about from different assumptions about reliability, dissimilar engineering approaches and a host of historical and operational parameters. The result is that ATC may be calculated differently on two sides on an interface. This appears to be an issue with the existing regulations, which do not provide for specific methodologies for calculating ATC and CBM.

Another issue is that ATC is often inaccurately posted on the OASIS even if calculated under the standard for the utility posting the ATC. Several market participants alleged that certain transmission providers in the Midwest were not accurately posting ATC.[29] One market participant alleged that transmission providers in the Midwest regularly post incorrect amounts for ATC and documented three examples. This appears to be an

[29] During this investigation, Staff received input from many market participants alleging inefficiencies or improprieties in the Midwest markets. Some market participants provided detailed documentation supporting their position, others provided some documentation and others made general assertions or specific assertions without supporting documentation. Many of the allegations were provided to Staff with requests for confidentiality under section 388.112 of the Commission's regulations (18 C.F.R. § 388.112 (2000)). As a result, this report only addresses the allegations generally, particularly those for which supporting documentation was provided. Enforcement Staff is evaluating the documents provided as substantiation for allegations of improprieties.

issue concerning enforcement of existing regulations concerning the posting of ATC on the OASIS.

This past summer, Commission Staff conducted an audit of all OASIS sites to determine compliance with section 37.6 of the Commission's regulations (18 C.F.R. § 37.6 (2000)). The audit findings were consistent with the allegations of the market participants. For example, Staff found that one transmission provider had no ATC records for constrained paths and that two transmission providers did not post ATC 7 days in advance. Staff is evaluating the data collected and is weighing follow-up options.

As a result of the lack of standardized procedures for calculating ATC and CBM, and the inaccurate posting of ATC, market participants cannot determine what transmission capacity is available so that they can make deals to provide energy to their customers. This has an effect on the amount of transactions and is a limit on liquidity.

2. Lack of Uniformity in Processing Transmission Requests and Scheduling Service

Another issue that came to light in the Midwest is that there is a lack of uniformity in processing transmission requests and scheduling service. This appears to be an issue with the scope and coverage of existing regulations regarding what is required. For example, reservations are not handled the same way across the entire Midwest. MAPP uses an e-mail procedure while the other three regions use OASIS sites. Two market participants complained that transmission providers are able to change their “Business Practices” on the OASIS sites with little or no notice. One of those market participants alleged that this is particularly a problem with regard to next hour service, which is not covered by the OATT, but which is a major source of business for marketers and can be a source of quick response power. One market participant complained of a unilateral change by a NERC region that limited the quantity of requests that could be made to certain delivery points within a certain time. The participant argued that the Commission should have approved the change before it took effect.

One market participant noted that a particular transmission provider waits until the end of the day to accept or deny requests for next-day service, instead of making decisions as requests are made on a first-come first-served basis. As a result, the market participant stated that it did not have the flexibility to make alternate deals if its request was wholly or partially rejected.

In addition to the issues concerning possible gaps in the existing regulations concerning transmission requests and schedules, there is also the issue of compliance with existing regulations in these areas. Staff's audit of OASIS sites in the summer of 2000 uncovered several areas in which Midwest transmission providers were not compliant or only partially compliant with the requirements concerning the posting of information on the OASIS. Specifically: some transmission providers did not always post the reasons for denial of transmission requests; others did not post schedules for daily non-firm transmission service; and some did not post all service requests and prices.[30] As with the deficiencies noted concerning ATC calculations, Staff is evaluating the data collected and is weighing follow-up options.

E. Inadequate Information for Real-Time Monitoring of Markets

As discussed earlier, Staff attempted to obtain data from transmission providers and NERC regions for this report, only to be told that the information sought was either not compiled or would not be compiled for several months. Staff was informed by the NERC regions that export and import data were not available and that the peak load data for 2000 would not be available for several months. In addition, we attempted to obtain from several transmission providers system-wide snapshots for days when TLRs were called, but were informed that snapshot data were not retained.

While section 37.6 of the Commission's regulations sets forth a number of posting and record-keeping requirements concerning individual transmission requests and transactions, as well as the capacity available to fulfill those transactions, the regulations do not require keeping aggregate load or import/export data. Moreover, while NERC requires load and peak data, these data are not required to be compiled on a real-time basis and there are no archival requirements. Thus, some NERC regions will not have non-coincident peak load data available for the summer of 2000 for several months while the regions compile such data from their individual members.

Because of this lack of data, as well as the lack of accurate data on TLRs and curtailments discussed above, it will be difficult for the Commission to monitor and react to market inefficiencies and problems, particularly in the active summer months, within a time frame in which quick action could be taken. This points out a gap in existing regulations regarding what information should be retained and made public in real-time to ensure that the market runs transparently and efficiently.

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[30] The audit generally only looked at postings for monthly firm, weekly firm and daily non-firm service.

Information Needs

Information transparency is necessary for a market to function efficiently. For this to happen, all participants must have equal and timely access to the information they need to make business decisions. This information already exists and is used by transmission providers to calculate operating parameters, such as Available Transmission Capacity (ATC), of their system. The general algorithm(s) used to calculate ATC and the underlying input data, such as Transmission Reserve Margin (TRM), Capacity Benefit Margin (CBM), projected load and system contingencies should be available on the transmission providers' OASIS sites. Detailed information, such as the load flow input data and the calculated solution, should be available upon request.

Market participants are particularly concerned about ATC calculations for the peak summer period. Transmission providers calculate ATC far in advance of the summer and then post these calculations on their OASIS sites. Typically, these calculations are very conservative, given the uncertainty that all maintenance and upgrades to the system may not be completed. Therefore, transmission providers normally use multiple contingencies which result in a smaller available amount of ATC.

As summer approaches, the uncertainty usually decreases since the estimates of available transmission and generation become more accurate. In addition, the weather forecasts for the summer months are more accurate the nearer the time to those months. Therefore, transmission providers recalculate the contingencies in the ATC and additional ATC is typically made available. To ensure that market participants have up-to-date knowledge of these changes and fair access to the additional ATC, transmission providers should publish on their OASIS sites the anticipated dates they will re-calculate ATC for the summer season.

It appears that many vertically integrated transmission owners may have incentives to resist efforts to make this information transparent and standardized, including information on the manner in which “native load” is handled in making these calculations. These incentives would also exist for transmission owners belonging to RTOs which allow them to individually calculate, or provide information to assist in calculating, ATC. As a consequence, the Commission may wish to eliminate the native load exemption and have all transactions under the same tariff. Given that all transactions serve load of one sort or another, all load would be treated in the same manner. This would provide all transmission owners the proper incentives to make relevant information available.

It has become apparent during this investigation that the Commission could benefit by having access to existing transmission information to provide a clearer understanding of the current market, as well as to assist in future studies. Transmission providers retaining and archiving the data listed below would meet this goal, as well as reduce the burden of future data requests on market participants and transmission providers. The following information would assist regulators' efforts to provide market oversight.

- Transaction data. This includes the number of transactions, the amount of each transaction in megawatts, and all connected paths from the Point of Receipt (POR) to the Point of Delivery (POD).

- TLR curtailment data. This includes the amount of curtailment on each transaction caused by a TLR, and the amount of relief on the congested flowgate.

- Retention by control areas of archived curtailment data for 3 years.

- Current network status. This is the real-time condition of the transmission network including transmission and generation outages.

The Commission could obtain all of the above information by having read-only access to the NERC Interchange Distribution Calculator (IDC).

It would also be useful for the Commission to have access, on an as-needed basis, to some other information that Security Coordinators have. First, it would help to have access to the daily reports from each Security Coordinator, which include the load, generation, scheduled transactions and tie-line flow data in each control area. Second, it would help to have access to standardized, historical TLR information. When transmission operators invoke a TLR Level 3 and above, they should retain the following system information in a standard format for 3 years: megawatt and megavar values for all generators, loads, flows and limits on all flowgates and tie-lines within their control area.

F. Lack of Investment in New Transmission Facilities

As discussed earlier, unlike with generation facilities, there has been little recent construction of transmission facilities in the Midwest. The reasons for this are a combination of regulatory siting requirements, particularly zoning, and the regulatory uncertainty of obtaining a return on the investment because of the evolution of RTOs and the possibility (or reality) of rate freezes in state retail access programs. Staff did not find evidence that the lack of investment in new transmission facilities currently affects the efficiency of the Midwest market. However, if the trend continues, the lack of new transmission facilities could affect the market as load and demand increases, particularly during a hot summer.

A number of market participants and state agency personnel told Staff that zoning requirements in general and resident opposition in particular act as a deterrent for utilities to initiate transmission construction projects. In addition, several market participants that provided information to Staff attribute the lack of construction of transmission facilities to the regulatory uncertainty perceived by the existing stakeholders. While the transmission system is currently owned by vertically integrated IOUs, it is unclear who will own or operate the system in the future after the evolution of RTOs. As discussed above, transmission siting can be a lengthy and costly endeavor. Since it is unclear who will eventually own, operate and value the transmission assets, the financial return on any investment is uncertain. Some market participants believe that the rate freezes and reductions that are being imposed as part of state retail access programs will act as a further hindrance to investment in transmission because they are uncertain as to whether they will be able to recover the costs of the facilities and make an acceptable rate of return.

G. System Reactive Capability

The transfer of large amounts of energy over long distances across interfaces requires sufficient reactive power support. Reactive power (MVAr), in effect, provides voltage support across the lines where real power (MW) is transferred. Unlike real power, the reactive component of power cannot be transmitted over long distances and must be provided locally. Most reactive power is supplied by generators, synchronous condensers and shunt capacitors.

Vertically integrated utilities perform this task for their own transmission systems. On the other hand, independent generators have little direct incentive to provide reactive power as no system is in place to compensate them. Once RTOs are in place, it is likely that some contractual agreement will be created to obtain the necessary reactive support. Without adequate reactive support, parts of the system can be susceptible to the threat of voltage collapse. This is especially a concern on days of peak demand on a hot summer's day.

H. System Impact Studies and Interconnection Requests

Several market participants raised concerns with Staff, about the lack of standard procedures and oversight for the conduct of system impact studies and processing interconnection requests. The participants complained about the length of time it took for transmission providers to handle system impact studies and interconnection requests and the costs associated with them.

Earlier this year, the Commission held that a transmission provider must process interconnection requests using the same procedures for handling transmission requests under the pro forma tariff.[31] As a result, some transmission providers have filed tariff sheets with the Commission setting forth specific procedures dealing with interconnection requests.[32]

A transmission provider may delay deciding on whether to grant a system interconnection and/or transmission request until it has conducted a system impact study to determine if it can grant all or part of the request. The Commission has held that a transmission provider should work diligently to complete a system impact study in 60 days, but may take more time as long as the transmission provider explains to the applicant the reasons that it needs additional time.[33] However, a transmission provider cannot use the existence of a backlog of interconnection requests to excuse its failure to complete a system impact study within 60 days. Several market participants alleged that transmission providers did not provide adequate reasons for completing a system impact study in a period longer than 60 days. For example, one market participant alleged that its in-house engineers estimated that the study should take less than half of the 60 day time period.

These allegations that market participants made to Staff are consistent with some of the recent complaints handled by the Commission's Hotline, staffed by the Market Oversight and Enforcement section. One complaint handled in the summer of 2000 concerned a transmission provider in the Midwest that was including language in an interconnection agreement that was inconsistent with the reasons for extending the period permitted for a system impact study. Earlier this year, the Hotline also handled a complaint dealing with the time for doing system impact studies, but, as it also alleged that the utility in question discriminated against the complainant, it is discussed infra.

Staff also heard complaints from market participants during this investigation about the cost of system impact studies. One market participant alleged and documented that a utility required a deposit of almost the entire cost of its transmission request, with a full refund for charges on capacity that turned out not to be available. Other market participants generally alleged that they were able to get a transmission provider to greatly reduce the price of a system impact study after complaining about the cost or threatening to complain to the Commission.

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31 Tennessee Power Company, 90 FERC ¶ 61,238 (2000).

32 *E. g.,* Entergy Services, Inc., 91 FERC ¶ 61,149 (2000); American Electric Power Service Corporation, 91 FERC ¶ 61,308 (2000) (AEP).

33 *E. g*., AEP, *supra*.

While a number of market participants raised the above concerns relating to system impact studies and interconnection requests, other market participants informed Staff that they have not had problems with the timing for system impact studies and interconnection requests. Therefore, it is not clear whether this is a widespread problem in the Midwest or an isolated problem.

NERC attempted to address the problem of the lack of formal facility connection requirements by including in its 1999 Pilot Compliance Program a requirement for transmission providers to submit documents setting out such requirements by a date certain. The NERC Pilot Compliance Program found that this standard was the provision most commonly breached. There were 81 members who had four or more instances of non-compliance (not all in the Midwest), and a total of 115 members with at least one instance of non-compliance with these standards.[34]

One reason for the complaints may be that transmission providers, as vertically integrated utilities, have no economic incentive to provide transmission access to a competitor, and in fact have incentives to discourage transmission access to competitors, particularly if such access would conflict with the transmission provider's service of its native load. The engineers and other technical staff who perform system impact studies on interconnection and transmission requests are the same personnel that perform such studies for native load. RTOs could provide the solution to this problem by handling all interconnection requests and system impact studies for their member transmission providers.[35] On the other hand, if existing control areas are maintained, the disincentive for processing third party interconnection and transmission requests would remain.

Regardless of whether problems relating to system impact studies and interconnection requests are widespread, the lack of standard procedures for those studies in the current regulations appear to have created uncertainty in the market, as public power and other market participants are forced to deal with different standards and procedures for every transmission provider for which they seek an interconnection request. This appears to inhibit the free flow of transactions within the region. Moreover, the lack of specific standards and procedures makes it difficult to pursue allegations of discriminatory conduct in this area. There may also be a compliance problem concerning transmission providers

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34Assessment of the 1999 NERC "Pilot" Compliance Program (November 17, 1999) at 5, 13.

35Prior to filing its RTO proposal, SPP filed a tariff provision setting forth procedures for generating facilities seeking to interconnect to SPP's transmission system, which the Commission approved on July 28, 2000. Southwest Power Pool, Inc., 92 FERC ¶ 61,109 (2000).

complying with the existing procedures in the Open Access Transmission Tariff for transmission service requests, which they are required to follow, under Tennessee Power, in the absence of separate tariff provisions dealing with interconnection requests.

I. Allegations of Market Power and/or Non-Competitive Behavior

Some marketers and Independent Power Producers alleged to Staff that transmission owners provide themselves or their merchant affiliates with competitive advantages. The allegations fall into two areas: general advantages allowed under current Commission regulations, and specific instances of non-competitive behavior by individual transmission providers in accepting requests, scheduling service, and in the conduct of studies.

1. Network vs. Non-Network Service

Entities with network service have built-in advantages to service their native load over non-network (point-to-point) service. The advantages that network service have over point-to-point service are priority of service under the OATT (which has separate provisions for network service and point-to-point service), lack of curtailment until a TLR Level 5 is called, and the lack of source/sink requirements. The Commission recognized that network service provides a flexibility that can confer a competitive advantage over point-to-point service.[36] This places any NUG at a competitive disadvantage vis-a-vis the vertically integrated utilities.

2. Specific Instances of Non-Competitive Behavior

In addition to the inherent advantages for transmission providers relating to network service under the current regulations, several market participants raised allegations of incidences in which individual transmission providers engaged in non-competitive discriminatory conduct.

One market participant raised specific allegations concerning two utilities in the Midwest, alleging that they had discriminated against it by approving or confirming later affiliate requests before the market participant's own requests, and provided supporting documentation. Three other market participants also raised allegations of transmission providers favoring their merchant affiliates. Enforcement staff is evaluating the information presented with these allegations.

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[36] Entergy Services, Inc., 92 FERC ¶ 61,108 (2000) (order on rehearing).

While the allegations discussed above suggest that there may be isolated instances of non-competitive behavior involving transmission providers in the Midwest, we lack enough information to determine if there is a systemic pattern of such behavior, at least within the framework of the current regulations.[37] In addition to the allegations raised to Staff for this investigation, the Commission's Enforcement Hotline handled seven complaints between January 1, 1999, and October 1, 2000, alleging non-competitive behavior by Midwest transmission providers, three of which resulted in Staff concluding that the transmission provider acted properly. As discussed earlier, Hotline matters are confidential, however the general issues raised included: refusing to disconnect customers until they paid stranded rate cost charges; not responding quickly enough to a request for an interconnection study for competitive reasons; denying a request for transmission of electricity purchased from a foreign utility while the transmission provider did same; withholding capacity; bumping a transmission request in favor of an affiliate's; requesting a letter of credit for a large amount and suggesting that the complainant use the transmission provider's marketing affiliate instead; and refusing to allow the complainant to participate in a program under the transmission provider's tariff. As stated above, Staff concluded that the transmission providers acted properly in three of the seven complaints. Two of the seven complaints were eventually resolved by the parties, and Staff determined that state law issues governed the remaining two complaints.

In addition to the informal complaints investigated by the Hotline, during the last two years the Commission has dismissed two complaints alleging anti-competitive behavior by Midwest utilities. Wisconsin Public Power Inc. v. Wisconsin Power & Light and Alliant Energy, Inc., 91 FERC ¶ 61,086 (2000) (Commission found that the dispute involved the interpretation of the transmission provider's tariff and a Power Supply Agreement and agreed with the transmission provider's interpretation) and Nordic Electric, L.L.C. v. Detroit Edison Company et al., 91 FERC ¶ 61,139, (2000) (Commission found that the transmission provider's reservation of capacity was proper to meet native load). The Commission currently has one complaint pending alleging non-competitive conduct regarding rollover rights. Dynegy Power Marketing, Inc. v. Ameren Services Company, Docket No. EL00-114-000.

In conclusion, the Commission has generally relied on passively receiving formal and informal complaints to determine if discriminatory behavior has occurred in the Midwest, rather than actively canvassing market participants to determine whether this is a

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[37] As discussed earlier, Staff lacked key data to determine if the increased incidences of TLRs were related to non-competitive behavior. As also discussed earlier, in areas in which the regulations do not provide standardized procedures, such as for the methodology for calculating ATC, it is difficult to determine whether a transmission provider is acting in a non-competitive manner.

systemic problem. Because time constraints allowed Staff to only canvass a limited number of market participants while preparing this Report, we cannot conclude whether there is a systemic problem of discriminatory behavior involving Midwest transmission providers. However, there appears to be evidence that some isolated instances of discrimination may have occurred and that several market participants believe that discriminatory behavior by transmission providers is a problem in the Midwest market. It is unclear whether the perception of non-competitive behavior would be better addressed through revising regulations dealing with areas in which the allegations are most prevalent, or by the Commission taking a more pro-active enforcement role, such as through compliance audits, rather than waiting to receive complaints either formally or informally through the Hotline.

6. Policy Options

This section provides some of the options available to the Commission to address the issues for the Midwest market discussed in Section 5.

A. Standardize Protocols and Procedures

- The Commission might require all RTOs, by a date certain, to submit the basis and methods for calculating ATC and TTC, as well as specific, standardized criteria for curtailment.

- Standardized procedures and criteria for multiple control areas might not get to the root of the problem (i.e., while it would make procedures and criteria consistent within a control area, there would still be the possibility of dozens of different procedures and criteria in other control areas; control areas would still control generation assets), the Commission could require that each RTO set a date certain by which it will take over all control area functions, thereby creating one control area for the entire area covered by the RTO.

- Regardless of the first two options, to avoid uncertainty during the interim period before RTOs become effective, the Commission could undertake to standardize methodologies for calculating ATC and TTC. The Commission could do this by requesting proposed standards, either from industry participants or NERC. The Commission could also direct NERC to develop procedures to ensure industry-wide dissemination of TLR information to market participants.

B. Improve Information on Market Performance

- Recognizing the difficulty in obtaining real-time transmission-related data on market functions, the Commission could require, on an ongoing basis, that all transmission providers retain, for a period of three years, all information pertaining to daily load, internal generation to meet that load, and imports and exports into its control area.

C. Standardize Procedures for System Impact Studies and Interconnection Requests

- Recognizing the uncertainty that may exist in getting generation interconnected to the transmission grid, the Commission could require transmission providers to submit tariff provisions containing a pro forma interconnection process that could be used by the Commission as a template for regions that do not, as yet, have an agreed upon interconnection process. These procedures would be specific to interconnection requests, as opposed to using the existing tariff provisions for transmission requests as is currently required under <u>Tennessee Power</u>.

- Alternatively, rather than using a pro forma interconnection provision, the Commission could require all transmission providers to submit tariff provisions of their own design for Commission approval.

D. Investigate Allegations of Market Abuses and Discriminatory Conduct

- While the Commission's Enforcement Hotline remains a productive option for resolving individual complaints concerning market abuses and discriminatory conduct, the Commission may choose to direct Staff to conduct formal investigations into entities about which a pattern of complaints has emerged.

E. Improve the Incentives for Open Access Transmission

- Reduce the advantages of network service over point-to-point service by requiring that native load be served under the same tariff provisions as other transmission services. Given that all transactions serve load of one sort or another, all load would be treated in the same manner. This would eliminate the current incentives that vertically integrated transmission owners have to favor their native load through the manner and method of calculating ATC and handling interconnection requests. It would also restore confidence among market participants that transmission owners were not calling TLRs to favor native load, because they would no longer have the incentive to do so.