COMMENTS OF THE MISSOURI PUBLIC SERVICE MISSOURI COMMISSION

REGARDING THE DEPARTMENT OF ENERGY'S 2009 TRANSMISSION CONGESTION STUDY AND THE DESIGNATION OF NATIONAL INTEREST ELECTRICITY TRANSMISSION CORRIDORS

I. Introduction

A. Major Concern of the Missouri Public Service Missouri Commission

At the outset, the Missouri Public Service Commission (Missouri Commission) wants to thank the Department of Energy (DOE) for the opportunity to provide input on its process for establishing National Interest Electricity Transmission Corridors (NIETCs). While cost allocation is not within the purview of the DOE under the 2005 Energy Policy Act, it is important for DOE to understand that the Missouri Commission's major concern is being allocated cost without commensurate benefits for the citizens of Missouri. The Missouri Commission has the obligation to ensure that charges paid by Missouri ratepayers whose rates fall under its jurisdiction are just and reasonable. In this regard, the Missouri Commission does not regard rate increases for transmission upgrades that provide little or no benefit to those ratepayers as being just and reasonable.

B. Summary of the Comments

These comments are organized to give DOE a perspective of the current situation in Missouri in regard to congestion. Section II gives the Missouri Commission's understanding of the purpose for the DOE's transmission congestion studies, including a brief summary of the DOE's findings in its 2006 Transmission Congestion Study. Notably, no NIETC areas were specified in this study for the Midwest, and the only congestion concerns that appeared in the study for the Midwest area were potential future issues related to exporting wind from the Dakotas – Minnesota area and the Oklahoma – Kansas area.

Currently the DOE is also funding a wind integration study that involves most of the Eastern Interconnection. The results of that study will not be available until June 2009. In addition, these studies appear to be based on an assumed National Renewable Portfolio Standard, which is not yet a component of our nation's energy policy. The Missouri Commission does not believe that this is the time for DOE to specify areas as qualifying for NIETC designation for transmission that might be needed at an unspecified future time for a nation-wide requirement for renewable resources. This does not mean that planning for such needs should not be performed today. Instead, until there is a clearly determined need for transmission to export electricity from committed wind power resources, and a clear understanding of the operational issues and cost involved in the introduction of large amounts of non-dispatchable energy into the power grid, DOE should not consider potential congestion associated with what is yet to be determined need as meeting the threshold of being in the national interest. It is the Missouri Commission's hope that, as the need and commitment for wind power consumption develops over the coming years, efforts by states and stakeholders working through regional state committees/organizations will be able to determine a cost allocation to all consumers that all states can find to be just and reasonable.[1]

Section III provides DOE with an overview of Missouri utilities and how they are connected through the transmission system within Missouri. This section explains that there are three primary transmission providers within Missouri: 1) Midwest Independent System Operator (MISO); 2) Southwest Power Pool (SPP); and Associated Electric Cooperatives (AECI). MISO, a Federal Energy Regulatory Commission (FERC) recognized Regional Transmission Organization (RTO), provides most of the transmission service on the east-side of Missouri, SPP, also a FERC recognized RTO, provides most of the transmission service on the west-side of Missouri, and AECI's transmission system is the primary connection between MISO and SPP in Missouri. In this regard, there appears to be no significant congestion with respect to market activity from Missouri into MISO or into SPP. In addition, the similarity between MISO and SPP market prices indicates either a similarity in the fuel mix of generation resources in the two RTOs, or that there is no significant congestion between these two markets.

Section IV is a brief conclusion regarding transmission congestion in Missouri as it relates to the DOE 2009 Congestion Study. The Missouri Commission does not expect that DOE's 2009 study will result in the designation of NIETCs, within MISO, SPP, or AECI, that will impact Missouri ratepayers. If that expectation proves to be incorrect, the Missouri Commission respectfully requests that DOE inform of such at the earliest possible time.

An appendix to the main body of the comments was prepared by our Chief Economist, Dr. Michael Proctor. This appendix discusses the more technical issues that Dr. Proctor will be addressing at the June 18 meeting in Oklahoma City on DOE's Transmission Congestion Study.

[1] It is important to note that the Missouri Commission has been very involved both at MISO and SPP in issues regarding transmission expansion and cost allocation.

II. Background

Under Section 1221 of the 2005 Energy Policy Act, DOE may designate as a NIETC any geographic area experiencing electric energy transmission ***capacity constraints or congestion that adversely affects consumers***. In this regard, Section 1221(a)(4) sets out the following key drivers for making a determination of what constitutes and adverse impact on consumers

- √ Impact of price of electricity on end markets
- √ Impact on economic growth / end markets from limited sources of energy
- √ Diversification of supply is warranted
- √ Energy independence is served
- √ National energy policy is enhanced
- √ Enhances national defense / homeland security

Further clarification of adverse impacts on consumers was set out in the National Electric Transmission Congestion Study issued in August 2006 by DOE in which DOE gave additional guidance to criteria by which it would evaluate whether or not congestion on the power grid would meet the threshold of needing to be classified as a NIETC. The following table summarizes these criteria.

Table 1

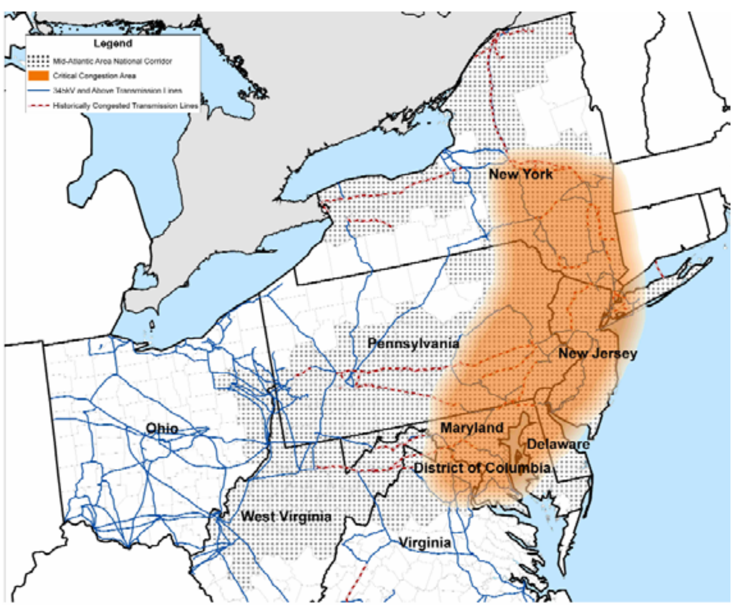
Criteria for Deciding NIETCs	
Reliability	Currently experiencing reiliability problems
	Future problems likely absent transmission upgrades
	Population of affected area
	Likely economic impact of grid failure
Supply Costs	Transmission upgrades lead to net economic benefit
	Source of economic benefits
Diversification	Reduce dependence on particular fuels
	Impact on security, price volatility and emergency suppies
National Policy	Further national energy policy
	Further national security

The 2006 congestion study by DOE found several congested areas within the Eastern Interconnection. These congested areas were classified into the following categories:

1. Critical Congestion Areas: “severe”
    i. Affected population is large
    ii. Congestion costs are high
    iii. Growing reliability problem
    iv. Severe national consequences of grid failure
2. Congestion Areas of Concern: “emerging”
    i. Congestion problem exist, but not yet severe
    ii. More information needed to determine
        a) Magnitude of the problem
        b) Relevance of transmission and other solutions
3. Conditional Congestion Areas: “future” location of generation
    i. Areas where new generations resources are likely to locate, but
    ii. New transmission needed to serve distant load centers

In the critical category were areas on the east coast running from New York south into the Baltimore – Washington DC. New England was determined to be a congestion area of concern. In the Midwest ISO, transmission in the Dakotas – Minnesota area would constrain the export of wind energy resources, and in the Southwest Power Pool, transmission in the Kansas – Oklahoma area would also constrain the export of wind energy resources. DOE determined that the New York to Washington DC congested areas should be designated as a NIETC:

Figure 1: Map of Designated NIETC for Eastern Interconnection



DOE is currently in the process of preparing for its congestion study for 2009. In this process, DOE is seeking information from the states regarding what the principle purposes and themes should be for this study.

III. Overview of Utility Service and Congestion in Missouri

A. Brief Overview of Population Centers and Utility Service Areas in Missouri

There are three major population centers in Missouri: 1) Saint Louis Metropolitan Area; 2) Kansas City Metropolitan Area; and 3) Springfield Metropolitan/Branson Area. In addition, the Central Missouri (Columbia – Jefferson City) area is experiencing rapid growth.

With respect to Investor-Owned Utilities, Union Electric Company (d/b/a AmerenUE) serves the majority of electric customers on the eastern half of Missouri; while the western half of Missouri is served by Kansas City Power and Light Company (KCPL), Aquila (d/b/a Aquila Networks -MPS and Aquila Networks – L&P) and The Empire District Electric Company (EMDE). The major municipal operated utilities are the City Utilities of Springfield, the City of Columbia, the City of Kirkwood (in the Saint Louis Metropolitan Area) and the City of Independence (in the Kansas City Metropolitan Area). In addition to these relatively large municipal companies, there are several small municipal utilities scattered throughout the state, as well as a system of generation, transmission and distribution cooperatives that serve the needs of rural electricity customers. The generation and transmission functions for the rural electric cooperatives are centralized through AECI. AECI's transmission system was built to provide generation to serve native load from geographically disperse locations (including federal power from the Southwestern Power Administration's (SWPA's) hydro projects and bordering utilities) and to move the power throughout the rural areas in Missouri. AECI is highly interconnected with all of the Missouri investor-owned utilities and many of the municipal utilities.

B. Transmission Providers and Transmission Service in Missouri

There are three major transmission providers in Missouri: 1) MISO; 2) SPP; and AECI. MISO provides transmission service on the eastern portion of Missouri, SPP provides transmission service on the western portion of Missouri, and AECI's transmission system provides the vast majority of interconnections between MISO and SPP in Missouri.

MISO is the transmission provider for AmerenUE, the City of Kirkwood, the City of Columbia and the smaller municipals in AmerenUE's control area. AmerenUE, the City of

Columbia and some of the smaller municipal utilities participate in the MISO energy markets.[2] SPP is the transmission provider for KCPL, the City of Springfield, EMDE, Aquila and some of the smaller municipal utilities located in the control areas of these larger utilities as well as providing contract services for the SWPA. KCPL, the City of Springfield, EMDE and some of the smaller municipal utilities participate in the SPP energy imbalance market.[3] Both MISO and SPP energy markets are based on nodal prices that reflect congestion through price differences at the various locations for generation and loads. For both electricity markets, the locational prices reflect the marginal cost of meeting an additional megawatt of demand at each location, where the locational marginal price is based on the lowest incremental cost from market offers not dispatched to meet market demand, but deliverable through the transmission system to the specific location.

The third transmission provider in Missouri is AECI, a non-FERC or Missouri Commission jurisdictional utility, who serves all but one of the distribution cooperatives and the small municipal utilities located in its balancing authority area/control area. Neither AECI nor SWPA participates in an RTO facilitated energy market, and therefore wholesale energy prices and congestion within their control areas are not transparent. However, where AECI and SWPA are interconnected with MISO and SPP, there are interface nodes where market prices are calculated. Thus, to some extent, congestion into and out of AECI or SWPA can be determined.

With the deregulation of wholesale power, the smaller municipals have become dependent on a mix of long-term and shorter-term purchased power agreements as sources of generation to meet their loads. These power contracts can, and do involve generation sources located outside the control areas of their previous utility providers. Much of the small municipal load is served through a joint arrangement called the Missouri Municipal Energy Pool. When these municipals are long on energy from their contractual sources, they will sell their excess purchased power into both the MISO and SPP energy markets, depending on the source of the contracted power. Long-term firm service is very limited in both areas. So, for example, while the Missouri Municipal Energy Pool might want to serve its load in either SPP or AECI from contracted resources in MISO, it has only been able to arrange a limited amount of firm transmission

[2] The City of Kirkwood is a full requirements wholesale power customer of AmerenUE, and is therefore does not directly participate in the MISO energy markets.
[3] At the present time, Aquila is not a participant in either the MISO or SPP energy markets.

service, and otherwise has to make such transfers using non-firm transmission service on an as available basis.

C. Some General Observations on Congestion in Missouri

In the MISO markets, AmerenUE is predominately a seller of electricity. This is because AmerenUE has lower-cost power (base-load coal) available to sell during non-system peak hours. As a general matter, AmerenUE's base-load coal plants operate at very high capacity factors, which is a strong indication that congestion is not a significant deterrent to sales. A major reason for this lack of congestion is the investment that AmerenUE has put into its transmission system in the recent past.[4] While the purpose of this investment was to increase the import/export capability into/out of the AmerenUE control area, it also resulted in reducing congestion on the AmerenUE transmission system.

In the SPP markets, KCPL is predominately a seller of electricity and EMDE is predominately a purchaser of electricity. KCPL has a greater percentage of its generation in base-load facilities than EMDE, while EMDE has a greater percentage of its generation in natural-gas fired and intermittent/wind generation facilities than KCPL. Aquila participates in bilateral markets as both a buyer and a seller, as its fuel mix is between that of KCPL and EMDE. Congestion in the SPP market relative to Missouri appears to be occurring at a small number of locations. In the 2007 State of the Market Report for SPP, the external market advisor and monitor for SPP reported that, "We found that 75% of the congestion occurred on just 10 flowgates (out of a total number of over 200 flowgates)."[5] From a Missouri perspective, the nodal prices for EMDE and KCPL are at or below the SPP system average as shown in figure 2 taken from the State of the Market Report.

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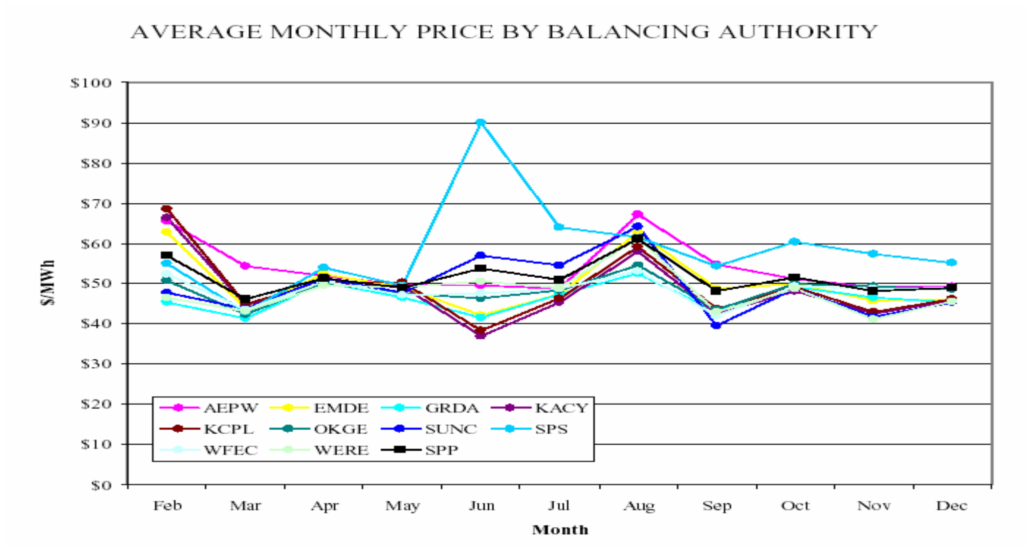
[4] Over the 2005 to 2007 time period, AmerenUE placed over $121 million in transmission upgrades in service that included eight major projects, most notably a new 345 kV line from Callaway to Franks costing $35 million and a new 345 kV line from Rush Island to St. Francois costing $16 million. These transmission upgrades addressed congestion issues within the AmerenUE control area.

[5] 2007 State of the Market Report; prepared by Boston Pacific Company, Inc.; released April 24, 2008. This report can be downloaded from the SPP website at spp.org.

Figure 2[6]



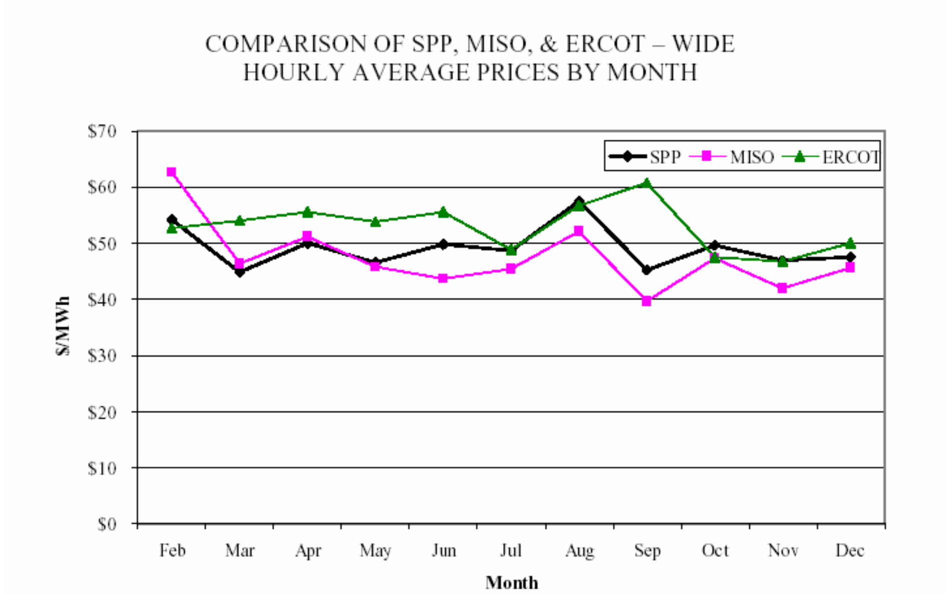
With respect to the SPP and MISO energy markets, it is important to note the lack of direct interconnections between MISO and SPP. There are only three tie lines with a total rating of 720 MVA connecting these two RTOs. On the other hand, there are 112 tie lines with a total rating of 19,224 MVA connecting SPP to AECI, and 63 tie lines with a total rating of 15,409 MVA connecting MISO to AECI. Thus, either east to west (from MISO to SPP) or west to east (from SPP to MISO) flows may significantly impact the AECI transmission system. If that transmission system is built primarily to move power from AECI generation to AECI's customer loads, this could imply significant congestion between the two RTOs.

Unfortunately, information comparable to nodal price data from MISO and SPP is not available for the AECI transmission system. As suggested earlier, another possible data source is for DOE to examine the nodal prices where MISO and SPP interface with AECI.

A similar type of price analysis can be performed at a higher level of aggregation by comparing average prices in SPP to those in MISO. The following graph from the SPP Market Monitor's report for 2007 shows such a comparison.

[6] Ibid, Figure III.4, p. 54.

Figure 3[7]



The similarity in SPP and MISO average monthly prices indicates that the two markets are tracking each other, at least on a monthly basis. The lower summer prices in MISO are an indication of the difference in fuel mix between the two RTOs, with the SPP region having a higher percent of natural gas. Absent any congestion between the two markets, the prices would be identical, but with a maximum difference in the range of $3/MWh, there does not appear to be a significant congestion issue between the two markets

IV. Conclusions

The Missouri Commission hopes that DOE finds these comments helpful, and offers additional assistance that might be needed regarding DOE's upcoming efforts in its 2009 Transmission Congestion Study. The Missouri Commission would be very surprised to find DOE designating a NIETC in its 2009 Transmission Congestion Study that would impact Missouri citizens. However, if our expectations are wrong and DOE finds critical or concern areas of congestion affecting Missouri, the Missouri Commission requests that DOE would make the Missouri Commission aware of this situation at the earliest possible date so that we might bring together the transmission expertise that exists within our staff and utilities to better understand the problem and provide DOE with timely information before it makes a final decision..

[7] Ibid, Figure III.1, p. 49.

Appendix A

Metrics for Congestion

A. Defining Congestion

In its agenda for the June 18 meeting in Oklahoma City, DOE announced that it was seeking information on several topics, including concepts of congestions and metrics to use for measuring such congestion. At the outset, the DOE may want to consider the following definitions of congestion.

a. Transmission constraints are operating limits on electricity flows that are set to maintain the reliable operation of the integrated power grid. These operating limits apply to both
   i. Individual transmission facilities; and
   ii. Groupings of transmission facilities that are highly loaded.

b. Congestion occurs when a transmission constraint restricts the desired dispatch of generation to meet load, resulting in flows across that transmission constraint at its specified operating limit.

These definitions are not significantly different from those included in the DOE published 2006 congestion study. However, an important difference is giving the definition of transmission constraints first, and then using that term in the definition of congestion.

B. Measuring Congestion

Given this definition of congestion, the next question to address is how to measure congestion on the transmission system. The following are some suggestions regarding improving the metrics used by DOE in its 2006 Transmission Congestion Study.

The five measures of congestion used by DOE in its 2006 congestion include:

1. Binding Hours - % time/year transmission constraint is loaded to its limit;
2. U90 - % time/year loading above 90%;
3. All-Hours Shadow Price (SP)[8] – simple average;
4. Binding-Hours SP – simple average; and
5. Congestion Rent – Sum over all hours (SP_h*MWh); where h = hours.

[8] A Shadow Price is the cost savings that would occur if the capacity of the congested transmission constraint is increased by one megawatt. This cost savings occurs as the more expensive generation downstream of the congestion is decreased by one megawatt and the less expensive generation upstream of the congestion is increased by one megawatt.

Possible refinements of these five measures that DOE may wish to consider are:

1. Binding Hours - Include both frequency and duration (% time/year and average duration) over the year;
2. U90 – include both frequency and duration;
3. All-Hours SP – graphical ranking of hours from highest to lowest;
4. Binding-Hours SP – covered by 3 above; and
5. Congestion Rent – graphical ranking of hours from highest to lowest.

The North American Electricity Reliability Council (NERC) standards for operation of the transmission system require transmission providers to specify as "flowgates" certain paths (from a source point to a destination point) on the transmission system that are subject to frequent congestion. There are several routes that electricity travels from the source to the destination of the flowgate, and NERC reliability standards require operators to restrict power flows on the flowgate to the maximum megawatts that can move from the source to the destination when the route carrying the largest megawatts of flow is out of service.[9] One approach to measuring congestion would focus on metrics of relative amounts (megawatts) and values (dollars) of congestion on the set of flowgates that have been previously specified by transmission operators. Taking this approach, the DOE could determine a relative ranking of flowgates. For example, rankings could be developed for flowgates from those with the most frequent congestion to those with the least frequent congestion, or from those having the highest congestion costs to those having the lowest congestion costs. This is precisely the approach taken by SPP in one of its most recent market reports.[10] What is interesting about this report is that the ranking of flowgates by frequency (shown in table 2 as number of five-minute intervals that the flowgate is constrained) is different from the ranking that comes from looking at the cumulative dollar values of marginal costs associated with the congestion.[11]

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[9] This is called an N-1 contingency condition. The concept is that the power grid would be able to continue to support the flows even under the contingency that the power line carrying the greatest flow is forced out of service by some unknown event.

[10] Supplemental Report Summarizing EIS Market Flowgate Congestion April 2008, published May 18, 2008, Figure A.4, p.7. This market report is available on the SPP website.

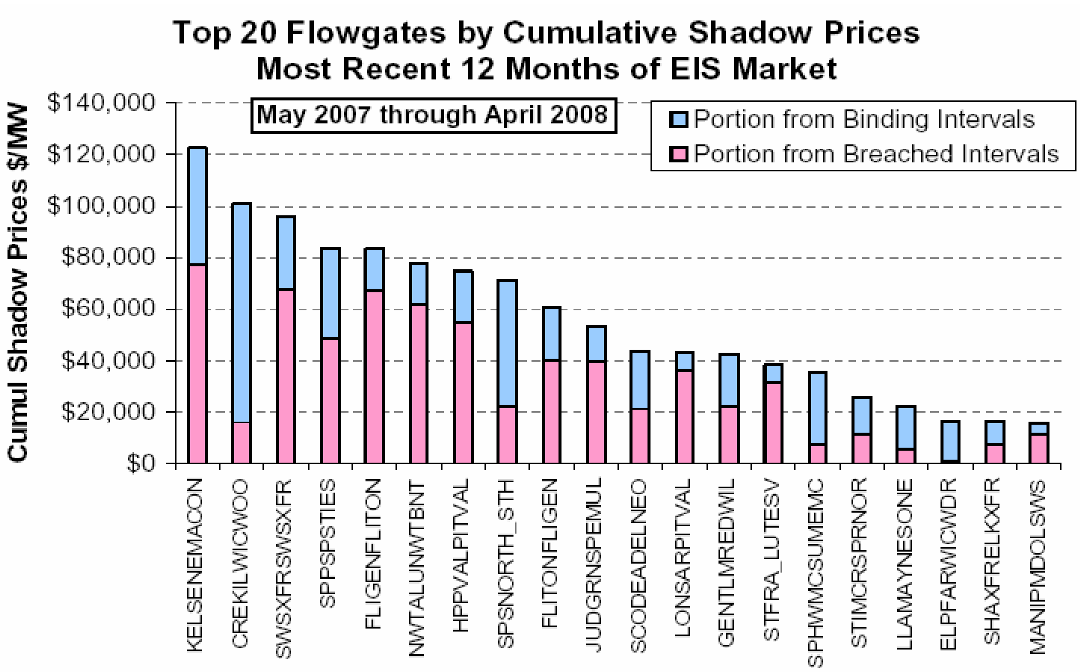
[11] Adding the Shadow Prices over a period of time (in this case, the twelve-months ending April 30, 2007) provides an indication of the cumulative incremental cost to the market from the constraint.

Table 2:

May 2007 through April 2008											
						Sorted Decreasing	Intervals with a Breach			All Congested Intervals	
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
Row Index	CONSTRAINT (FLOWGATE)	FG ID	FG RC	BINDING CONSTRAINT-INTERVALS	BREACHED CONSTRAINT-INTERVALS	TOTAL CONGESTED CONSTRAINT-INTERVALS	MAX MW BREACH	MEDIAN MW BREACH	MEDIAN BREACH AS % OF LIMIT	AVERAGE 5-MINUTE SHADOW PRICE ($/MW)	CUMUL HOURLY SHADOW PRICE ($/MW)
	ALL CONSTRAINTS			71,496	6,790	78,286	387	6	2.3	$253	1,652,316
1	SPPSPSTIES	5247	SPP	28,385	376	28,761	326	38	27.5	$35	$83,842
2	SPSNORTH_STH	5196	SPP	14,982	232	15,214	317	25	3.7	$56	$71,338
3	TEMP03_14375	14375	SPP	4,461	75	4,536	30	4	1.3	$274	$103,719
4	CREKILWICWOO	5077	SPP	3,719	117	3,836	53	6	3.1	$316	$100,965
5	HPPVALPITVAL	5203	SPP	1,989	378	2,367	80	7	2.3	$378	$74,559
6	SWSXFRSWSXFR	5330	SPP	1,600	523	2,123	80	4	0.7	$542	$95,937
7	SPHWMCSUMEMC	5204	SPP	1,997	48	2,045	25	4	1.8	$207	$35,268
8	SCODEADELNEO	5078	SPP	1,141	159	1,300	37	5	2.3	$406	$43,977
9	GENTLMREDWIL	6007	MAPP	1,156	142	1,298	145	8	2.0	$395	$42,758
10	KELSENEMACON	5328	SPP	710	486	1,196	15	1	1.1	$1,230	$122,613

The following graph, included in that same report, ranks constraints by their cumulative incremental cost to the market over the twelve months ending April 30, 2008.

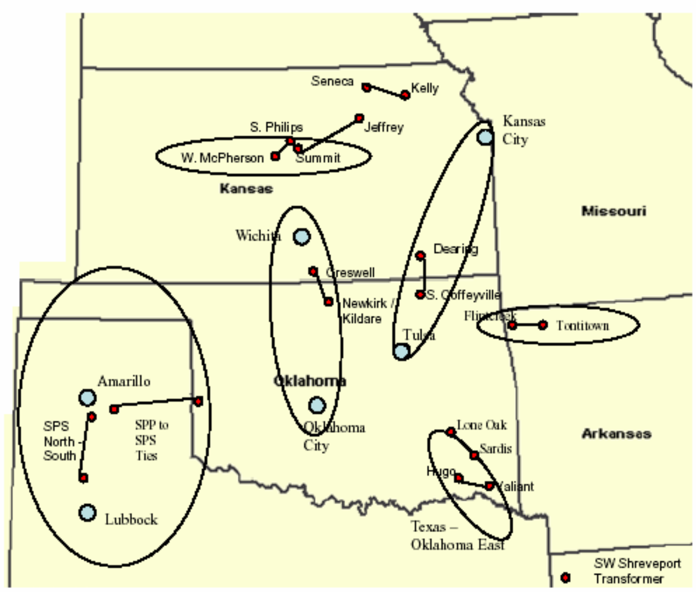
Figure 4[12]



[12] Ibid; Figure A5, p.9.

While these traditional measures that focus on transmission flowgates, or in some cases even transmission elements, are appropriate from the perspective of the details on transmission facilities that may be good candidates for economic upgrades, DOE's focus on congestion should be at a higher level. More specifically, the focus should be on areas rather than specific transmission elements or flowgates of the transmission grid that are constrained. An example of this type of analysis is provided in the SPP Market Monitor's report for 2007 where a few constrained areas were identified based on the Market Monitor's analysis of constrained flowgates and transmission elements over the operation of the SPP Energy Imbalance Market from its start up in February 2007 through December 2007. This analysis led the Independent Market Monitor to identify the following six constrained areas within the SPP market.

Figure 5[13]



From south to north, the six constrained areas identified are:

1. Texas Panhandle
2. Northeast Texas / Southeast Oklahoma
3. Oklahoma to Wichita
4. Tulsa to Kansas City
5. Northwest Arkansas
6. Central Kansas[14]

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[13] Ibid, Figure III.7, p. 71.

[14] It should be noted that the congestion in this area is due to a "temporary flowgate" created to address a reliability concern resulting from the outage of a substation breaker. Congestion was relieved when the outage was resolved.

It is important to note that SPP planning is in the process of or has addressed each of the transmission system constraints involved for these congested areas. Such evaluations initially address whether or not reliability upgrades are needed over the next ten years, and additionally address whether or not any upgrades related to these congested areas should be included for economic reasons.[15]

[15] Upgrades justified for economic reasons will be included in what is called a Balanced Portfolio. At this time, the SPP Regional State Committee (RSC) has approved the concepts of a Balance Portfolio and the tariff language is under development for submission to the Federal Energy Regulatory Commission (FERC) later this summer.