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Witness: Sarah L. Kliethermes
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MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

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Missouri Public
Service Commission

REBUTTAL TESTIMONY

OF

SARAH L. KLIETHERMES

GRAIN BELT EXPRESS CLEAN LINE LLC

CASE NO. EA-2014-0207

Jefferson City, Missouri
September 2014

** **Denotes Highly Confidential Information** **

NP

Exhibit No. 206
Date 11-10-2014 Reporter Stewart
File No. EA-2014-0207

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	))))))))))	Case No. EA-2014-0207

AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Sarah L. Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the following Rebuttal Testimony in question and answer form, consisting of 41 pages of Rebuttal Testimony to be presented in the above case, that the answers in the following Rebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Sarah L. Kliet
Sarah L. Kliethermes

Subscribed and sworn to before me this 15th day of September, 2014.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer
Notary Public

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SARAH L. KLIETHERMES

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OF

SARAH L. KLIETHERMES

GRAIN BELT EXPRESS CLEAN LINE LLC

CASE NO. EA-2014-0207

Q. Please state your name and business address.

A. My name is Sarah L. Kliethermes and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. Who is your employer and what is your present position?

A. I am employed by the Missouri Public Service Commission ("Commission") and my title is Regulatory Economist III, Economic Analysis Section, Tariff, Safety, Economic and Engineering Analysis Department, Regulatory Review Division.

Q. What is your educational background and work experience?

A. I completed a Bachelor of Science degree in Historic Preservation from Southeast Missouri University in Cape Girardeau, Missouri, and a Juris Doctorate degree from the University of Missouri, Columbia. I have been employed by the Missouri Public Service Commission since May 2006. Prior to transferring to the Economic Analysis Section in July 2013, I was a Senior Counsel in the Staff Counsel's Office. A copy of my credentials and case experience is attached as Schedule SLK-1.

Overview

Q. Have you reviewed the direct testimony of Grain Belt Express witnesses David Berry concerning Grain Belt Express's characterizations of the need and benefits of the Project, Dr. Galli regarding the interconnection and operation of the Project if completed, Gary Moland's testimony regarding production modeling, and Timothy Gaul describing the routing of the Project in Missouri?

A. Yes. I have reviewed these filed testimonies, among others.

Q. Do you agree with Mr. Berry's characterizations of the impact of the Grain Belt Express Project on Missouri retail customers?

A. I did not find that Mr. Berry presented adequate evidence to support his assertion that the Project will ultimately result in lower electric rates for Missouri consumers. I also have concerns with the use of the information prepared by Mr. Moland that was relied upon by Mr. Berry.

Q. Is the evidence provided in these testimonies and Mr. Gaul's testimony consistent with the quality and quantity of evidence that has been provided to the Commission in other line certificate cases over the last ten years?

A. As will be discussed in greater detail throughout my testimony, it is not.

Q. What information has not been presented here that has been available for the Commission's consideration in other recent regional and inter-regional line certificate Applications?

A. In other line certificate cases, the Commission has had available:

1) Completed interconnection studies,
2) Information regarding how the involved RTO/ISO determined the benefits of the Project,
3) Results of the involved RTO/ISO determination of the benefits of the Project,
4) The involved RTO/ISO's determination of estimated costs and benefits for Missouri investor-owned utilities participating in that RTO/ISO,
5) A prior determination of need, finding of financial capability, and determination of public interest by a public body charged with centralized administration of transmission networks.

Q. Does Staff recommend that conditions be imposed on any authorization of Grain Belt Express' receipt of a CCN to build and operate the Project as described in the testimony of Staff witness Daniel I. Beck?

A. Yes. Staff witness Daniel I. Beck is presenting all of Staff's recommended conditions in his rebuttal testimony. Some of those conditions are that certain items be completed. Others are that certain items be brought back to the Commission for Commission approval (or acceptance) prior to any condemnation of Missouri real property. Staff and other parties to this case should be given an opportunity for review and comment on these items requiring Commission approval (or acceptance).

Q. Which of Staff's recommended conditions are you sponsoring?

A. Regarding retail rate impact on Missouri customers of investor-owned utilities, I recommend that the Commission order Grain Belt Express to perform a number of studies and to provide for Commission approval in compliance with the Tartan Criteria and other applicable law, the following items:

1. Production modeling that incorporates:
    - Day Ahead market prices to serve load,
    - Real Time market prices to serve load,
    - Ancillary Services prices to serve load,[1]
    - Day Ahead market prices realized by Missouri-owned or located generation,
    - Real Time market prices realized by Missouri-owned or located generation,
    - Ancillary Services prices realized by Missouri-owned or located generation,
    - An estimate of the impact of Grain Belt Express's Proposal on the operational efficiency of Missouri-owned or located generation.
2. Production, transmission, and economic modeling or analysis to determine:
    - The cost of transmission upgrades that may be economical to resolve the transmission constraints that its energy injections will cause or exacerbate.
    - The impact of using the entire design capacity of the Missouri Converter station.
    - The net impact to Missouri utilities of picking up Missouri energy by day for export to PJM or SPP.

[1] Modeling for the Real Time and Ancillary Services markets should be based on a more reasonable wind shape that varies within the hour.

- Whether the variability of the injected wind could be better managed in the SPP prior to injection.

Staff recommends that the Commission order Grain Belt Express to provide to the Commission documentation of:

1. Grain Belt Express's commitment that it will not seek RTO cost allocation for the Project itself, nor for any transmission system upgrades necessary to safely accommodate the Project.
2. Grain Belt Express's commitment to utilize only the studied portion of the Missouri Converter station.

Q. Would Staff have additional or different concerns with Grain Belt Express's Proposal if the physical infrastructure described in the Application were operated in a manner differently than that described in the Application?

A. Yes. This testimony only addresses Staff's concerns if the infrastructure is operated to deliver wind energy as produced in Kansas from Kansas into and through Missouri, without any mitigation of the wind variability occurring at or before the Kansas Converter Station. Also, this testimony does not address use of the Missouri Converter Station to flow power from Missouri into either the SPP or the PJM.

Impact of the Proposal on Missouri Retail Electricity Rates

Q. Do you agree with Mr. Berry's testimony that "[t]he Project will reduce wholesale electric power prices in Missouri and in surrounding states, which will decrease the cost of load serving entities to purchase electric power from the MISO and PJM markets, ultimately resulting in lower electric rates for consumers."[2]

A. No. This statement has several problems.

1. The wholesale electric power market consists of more than just the Day Ahead power market, which is all that has been modeled by Grain Belt Express. It is also necessary to model the impacts of the Project on the Real Time and Ancillary Services markets, and possibly also the MISO capacity market. Related to this problem is the fact that Grain Belt Express modeled the entire Eastern Interconnection as a single market, which under-recognizes the challenges of wind integration.[3]
2. Grain Belt Express has not taken into account that Missouri retail rates are offset by the profits that investor-owned utilities make by selling energy into the wholesale power market.[4] In other words, if the price of energy is reduced in hours when Missouri utilities generate energy in excess of that utilities' own load, the ultimate rate paid by the Missouri retail customer goes up.
3. Grain Belt Express' modeling was performed with both the Missouri and the Illinois/Indiana converter station running concurrently. This makes it difficult to determine whether the impact of the Missouri converter station itself would increase or decrease Missouri rates.

Q. What type of study did Grain Belt Express perform as the basis of its assertion that its Project would reduce wholesale power prices?

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[2] Berry Direct Testimony, at page 29. Also, in his pre-filed Direct Testimony, at page 4, Mr. Berry testifies, "Lower renewable energy compliance costs and lower wholesale electric prices will both result in decreased costs to end-use electric customers." In his pre-filed Direct Testimony, at page 33, David Berry testifies, in part, "Q. Why are reduced wholesale electric prices relevant to end-use electricity consumers? A. Lower wholesale electric prices reduce costs for load serving entities and therefore for consumers who pay cost-based rates, as is the case for most electric users in Missouri. When prices are affordable, utilities who serve retail load can buy from the wholesale market instead of running their own generation. Lower wholesale prices will mean incumbent utilities run their most expensive generation less often, reducing fuel costs. Finally, for certain Missouri utilities, purchasing wholesale electricity from the MISO market is always an alternative to building new generation. Market prices serve as a cap on the cost of new generation because utilities can elect this option if purchasing wholesale power is cheaper than building new generation."

[3] See Schedule SLK-2 National Renewable Energy Laboratory "Eastern Wind Integration and Transmission Study: Executive Summary and Project Overview," revised February 2011, which studied the impact of various levels of wind integration on the Eastern Interconnect, modeled for the year 2024 as seven balancing authorities. Regarding this assumption, at page 27 and 28, the report states that "The levels of wind generation considered in EWITS increase the amount of operating reserves required to support interconnection frequency and balance the system in real time. Contingency reserves are not directly affected, but the amount of spinning reserves assigned to regulation duty must increase because of the additional variability and short-term uncertainty of the balancing area demand. **The assumption of large balancing areas does reduce the requirement, however. Under the current operational structure in the Eastern Interconnection, the total amount of regulation that would need to be carried would be dramatically higher.**" [emphasis added]

[4] See Response to DR 19.

A. Grain Belt Express modeled an hourly energy market for the entire Eastern Interconnection that included wind generation in Kansas, and the delivery of that wind energy at the two proposed converter stations in Missouri and at the Illinois/Indiana border. This modeling is similar to that of the Day Ahead market employed by MISO. By quantity, most of the energy generated and purchased by Missouri utilities is transacted through a Day Ahead type market. However, much of the operational impact of wind integration is dealt with through the Real Time and Ancillary Services market, which were not studied by Grain Belt Express. Staff's concern with the study will be described in detail below.

Q. Assuming Grain Belt Express' Project would reduce wholesale power prices in Missouri, would Missouri retail rates for electric service be expected to decrease with the Project implemented as described in the Application?

A. The retail rates paid by electric utility customers would not necessarily decrease if wholesale power prices in Missouri decrease. For customers of some Missouri utilities, it is probable that retail rates would increase. Grain Belt Express has not studied or presented information on the net impact on Missouri retail customers of several off-setting impacts. Staff is concerned that Grain Belt Express misunderstands Missouri retail rate structures, particularly regarding the use of Off-System Sales Margin Revenues ("OSSMR") to reduce the retail rates paid by Missouri customers.[5]

Q. What are the bases of Staff's concern?

A. Primarily, Grain Belt Express does not recognize the value to Missouri retail ratepayers of existing investments in generating plant made by Missouri's investor-owned utilities.[6] Missouri retail rates are adjusted for profits that investor-owned utilities make selling energy at wholesale. So decreasing wholesale energy prices may increase or decrease

[5] See Response to DR 19.
[6] See Response to DR 19.

a Missouri customer's electric bill. Additionally, as mentioned above, there is more to the wholesale energy price than just the Day Ahead hourly market. Missouri utilities will experience changes in both costs and revenues in each of the energy markets – Day Ahead, Real Time, and Ancillary Services. Additional study is necessary to estimate the magnitude of these six off-setting factors to determine the net impact on Missouri retail rates.[7]

Q. Using Grain Belt Express's hourly market modeling assumptions and modeling, what is the economic value of the energy Grain Belt Express assumes it will inject in Missouri for the year 2019?[8]

A. Grain Belt Express has modeled injecting 2,108,336 MW into Missouri. Applying Grain Belt Express's LMP projections results in an economic value of $65,847,132, or $31.23 per MWh for the energy injected.

Q. What is the economic value of the energy Grain Belt Express would displace from Missouri generation sources using the same assumptions?

A. Applying Grain Belt Express's base case LMP projections to the hourly profile of wind injection results in an economic value of $68,925,103, or $32.69 per MWh for the displaced Missouri-generated energy. These figures do not include any offset for changes in the price of energy as applied to load, or the reduction in sale price for energy that is sold by Missouri generating sources at the reduced LMP.[9]

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[7] Grain Belt Express's Proposal may also impact Missouri utilities' costs and revenue opportunities in the provision of transmission services, which is discussed elsewhere in this testimony, and also that of Staff witness Michael Stahlmann.

[8] This modeling is based on concurrent injections in Missouri and Illinois. As discussed below, it is expected that the impact of a Missouri-only injection would be different.

[9] For example, using the Grain Belt Express modeling results, the average Palmyra LMP for the hours when wind is blowing in Kansas (weighted by the hourly Missouri injection used in the analysis) decreases 2.88% (from $32.16/MWh without the Project, to $31.23 with the Project) with the addition of the project. Concerning the viability of Missouri wind projects, this impact would be slightly mitigated in that there is a time difference between when peak wind would be blowing in Kansas and when peak wind would be blowing in Northeast Missouri.

Q. What does Grain Belt Express assume for the cost of energy as applied to load in this model?

A. For the entire state of Missouri, Grain Belt Express models that 87,645,563 MWh will be consumed in the year 2019. Applying the hourly load profile to the non-injection hourly LMP profile results in an annual cost to serve load of $3,072,184,423, for an average of $35.05 per MWh. Applying the same hourly load profile to the LMP profile that reflects both injection sites results in an annual cost to serve Missouri load of $3,049,228,856, or $34.79 per MWh. The total-state difference in cost to serve load is a reduction of about $23 million. Assuming approximately 1/3 of that amount is attributable to Ameren Missouri's cost to serve load results in about a $7.6 million annual reduction to Ameren Missouri.

Q. What impact do those numbers have on Missouri retail rates?

A. Given the location of the converter station and existing transmission constraints, it is reasonable to assume that most of the generation that will be displaced in the MISO Day Ahead market by the Missouri wind injection would have been generated by Ameren Missouri. Also due to the location of the converter station and the associated transmission constraints, it is reasonable to assume that most of the impact on LMP change at the injection "gen node" will ultimately impact the calculation of Ameren Missouri's load node. If both of these assumptions are made, the impact would be to reduce Ameren Missouri's cost to serve load by approximately $7.6 million in the year 2019, and to reduce Ameren Missouri's OSSMR by approximately $68,925,103, less the value of whatever fuel and other variable expense Ameren Missouri does not expend.[10]

Q. Is it reasonable to assume that the reduction to OSSMR would be greater than $7.6 million?

[10] See discussion below regarding how much fuel would likely be conserved.

A. Based on the hours and plant types involved, I would be surprised if the net impact to Ameren Missouri's OSSMR was less than $7.6 million. Therefore, using this crude analysis, it is likely that the Project would decrease Ameren Missouri's cost to serve load by roughly $7.6 million, but would also decrease Ameren Missouri's OSSMR by an amount greater than $7.6 million.

Q. What does all this data mean for the net cost of Ameren Missouri energy?

A. Using the data available as modeled by Grain Belt Express, I would expect Ameren Missouri's average net cost of energy to be higher with the Project than without the Project.

Q. Is this analysis sufficient to determine whether this Project will increase or decrease Missouri retail rates, particularly for customers of Ameren Missouri?

A. No. These calculations should be made through production modeling of the day-ahead and real-time markets, including modeling for ancillary services requirements, costs, and revenues.

Q. More specifically, what studies are necessary to determine the range of impacts to the retail rates paid by customers of Missouri investor-owned utilities?

A. To more reasonably estimate the impact its Project would have on Missouri retail rates for customers of investor-owned utilities, Grain Belt Express should perform production modeling that incorporates:

- Day Ahead market prices to serve load,
- Real Time market prices to serve load,
- Ancillary Services prices to serve load,[11]
- Day Ahead market prices realized by Missouri-owned or located generation,
- Real Time market prices realized by Missouri-owned or located generation,
- Ancillary Services prices realized by Missouri-owned or located generation,

[11] Modeling for the Real Time and Ancillary Services markets should be based on a more reasonable wind shape that varies within the hour.

- An estimate of the impact of Grain Belt Express's Project on the operational efficiency of Missouri-owned or located generation.

Q. What other conditions or studies are necessary to more reasonably estimate the impact of the Grain Belt Express Project on rates for Missouri retail customers, particularly those of investor-owned utilities?

A. Grain Belt Express has not studied the impact to retail rates of any RTO cost allocation it may seek in the future. Grain Belt Express should commit that it will not seek RTO cost allocation for the Project itself, nor for any transmission system upgrades necessary to safely accommodate the Project. [12]

Also, Grain Belt Express has not studied the impact to retail rates of any RTO cost allocation for Projects that an RTO may determine are necessary to minimize congestion caused by the Projects. Grain Belt Express should study what transmission upgrades may be economical to resolve the transmission constraints that its energy injections will cause or exacerbate.

Finally, to the extent Grain Belt Express has studied the wholesale market impact of the Missouri converter station, it has not presented a study of the whole capacity of the Missouri Converter station. Grain Belt Express should commit to utilize only the studied portion of the Missouri Converter station, and should study the impact of using the entire design capacity of the Missouri Converter station.

Q. Why are these items of concern to Staff?

A. Without information on the Project's direct impact to retail rates through increased costs of energy and transmission, or decreases to off-setting off-system sales

[12] For example, for the transmission upgrades necessary in Kansas to collect the wind energy, Grain Belt Express estimates the delivery facilities which will connect all of the Kansas wind turbines to the Kansas converter station to be between $100 million and $320 million, based on 50 to 160 miles of 345 kV double circuity line at a cost estimated at $2 million per mile. (GBX response to MLA DR 60, provided in response to Staff DR 132.)

margins, Staff is unable to state whether the Project will likely increase or decrease the electricity bills for Missouri's investor-owned utility consumers.

Impact of the Project on the Integrated Energy Market Pricing

Q. What is the likely operational impact of Grain Belt Express' Project on the Day Ahead, Real Time, and Ancillary Services markets?

A. Additional study is necessary to better estimate the impact of the Project on these markets. Those additional studies are described in Staff's recommendation provided above. However, Staff has reviewed the PROMOD results that Grain Belt Express has made available to Staff. Staff has concerns about the operational impact of Grain Belt Express' Project based on these study results.

Q. What are Staff's concerns based on the study results that Staff has had available for review?

A. Staff is primarily concerned that the Project will create a great deal of transmission congestion in northeastern Missouri. Staff is also concerned that the manner in which Grain Belt Express presents its study results in its filed testimony conflates the energy impact of the two proposed delivery converter stations. Staff's concern with this second issue is that this presentation skews the Commission's evaluation of Grain Belt Express' Application. Finally, Staff is concerned that Grain Belt Express' Project will result in less efficient operation of the generation fleet and integrated markets located in the Eastern Interconnection.

Q. What is a Day Ahead integrated energy market?

A. All of Missouri's regulated electric utilities participate in a RTO/ISO.[13] Essentially, each utility or Independent Power Producer ("IPP") participating in a given

[13] Ameren Missouri participates in MISO. Empire, GMO, and KCPL participate in the SPP.

market generates energy into the Day Ahead market based on what the RTO/ISO orders for a given hour, and is paid for that energy at the Day Ahead Locational Marginal Price ("DA-LMP") at the point the generator delivers power onto the interconnected transmission system.[14] Simultaneously, each utility purchases energy from the RTO/ISO market based on that utility's load in each hour, paying the LMP for that energy for the aggregate load node for the geographic area served by the utility.

Q. Is the price of energy determined by an integrated market, or by a particular buyer and a particular seller?

A. Both, but for different purposes. For example, if a wind generator in Kansas enters a contract with a municipal utility in northeast Missouri to sell the utility wind energy for $40 per MWh, to be delivered to Palmyra, the utility owes that generator $40 for each MWh of that wind energy. However, in practice, that utility (assuming it is a MISO participant) would also have a transaction with MISO where MISO owes the utility the appropriate LMP per MWh for each MWh delivered to Palmyra pursuant to the utility's contract. Concurrently, the utility would owe MISO the appropriate LMP per MWh for each MWh the utility draws through its load nodes. Since the Grain Belt Express LMP modeling results in a 2019 average energy price (Day Ahead only) of $31.23 per MWh, in this example, the utility would owe $40 per MWh to the Kansas generator, and be receiving (on average and not adjusted for losses) $31.23 per MWh back from MISO, which MISO will offset against the utility's cost of serving load.

Q. What is a Real Time energy market?

A. Each utility or IPP participating in a given market generates energy into the Real Time market based on what the RTO/ISO orders for a given intra-hour interval (such as

[14] The locational marginal price (LMP) is the price of energy at a particular place and time in an integrated energy market. The LMP is made up of three components, Energy, Congestion, and Losses.

a 5-minute interval in the MISO) to make up for deviations from the generation that was ordered in the Day Ahead market, and deviations from the load predicted in dispatching the Day Ahead market. The generator is paid for that energy at the Real Time Locational Marginal Price ("RT-LMP") at the point the generator delivers power onto the interconnected transmission system. Simultaneously, each Load Serving Entity ("LSE") pays or is credited for the deviation in required energy at the RT-LMP for that energy.

Q. What are ancillary services?

A. Ancillary services are services necessary to support the energy market. For example, voltage support is an ancillary service that ensures that some energy is generated close enough to each load pocket that adequate voltage is delivered to the transmission system. Another type of ancillary service is regulating service, which is the use of a quick-responding generating unit to "follow" load to ensure that exactly enough energy (within a very small tolerance) is put onto the transmission system to meet the amount of energy taken by load on a fraction-of-a-second basis.

Q. What are the components of a LMP at a given node on the transmission system?

A. A LMP is made up of three components: Energy, Congestion, and Losses.

Q. How will the energy component of a LMP be impacted by Grain Belt Express's Project?

A. It depends on the hour. For a given hour in the DA market (or a given interval in the RT market) the energy component is the bid price of the most expensive unit that has been called upon to generate in that interval.[15] Generally, units are dispatched from least- to most-expensive, so the energy component of the LMP for the entire market footprint will be the cost of dispatching the next MW of generation. Because wind tends to have very low variable cost, and is often subsidized by a production tax credit, wind tends to be very low in a dispatch stack for any market. Therefore, to the extent the Grain Belt Express Project is used to import wind to the MISO and the PJM from the SPP, it is likely that Grain Belt Express' Project would displace any higher-bid generation that can be displaced in the hours that it is delivering wind, which would drop the energy component of the LMP to a lower bid-price for those intervals.

Q. How much will Grain Belt Express' Project reduce the energy component of the LMP in hours when the wind is blowing?

A. Not very much. The energy component of the LMP tends to be quite low in hours when the wind is blowing for three reasons. First, the wind tends to blow the strongest in hours that are not coincident with peak, such as at night and during the winter.[16] Graphs comparing the coincidence of wind with load requirements as modeled by Grain Belt Express are provided in Schedule SLK-3. Second, there are existing wind projects in the MISO and

[15] In general, the units available for dispatch in a particular market are thought of as listed from least expensive to run, to most expensive to run, based on the bids made by the owners of the generation resources. This list is known as the generation stack. Included in the stack are units designated as "must run" by their owners. Subject to system demand, these "must run" units will be dispatched first, and will be compensated at the rate of the last bid-in unit to have been dispatched. All units running in an interval will be compensated at the rate for the last unit – the most expensive running unit – to have been dispatched in that interval.

[16] For example the MISO load peak for 2013 occurred on July 18, but supply conditions were tighter on July 17 due to a reduction of wind output. See page 6 of MISO 2013 State of The Market Report, attached as Schedule SLK-4. Also, as stated at page 43 of the MISO 2013 State of the Market Report, "wind resource output is negatively correlated with load and often contributes to congestion at higher output levels, so hourly-integrated prices often overstate the economic value of wind generation," and at page 48, "that wind output is substantially lower during summer months than during shoulder months, particularly during the highest load hours. This reduces its value from a reliability perspective." However, wind is coincident with some demand at night, particularly during the winter. See http://www.nrel.gov/docs/fy09osti/46275.pdf

the PJM footprints, and these projects have already lowered the LMPs while wind is blowing.[17] A third aspect that limits the reduction of the energy component is the relationship between the energy component and the congestion component, which will be discussed below. For the MISO footprint, "[w]ind resources typically set price in confined areas where its output is contributing to localized congestion, and it rarely sets prices system wide."[18]

Q. What impact will the Project have on the MISO and the PJM energy components of the LMP in hours when the wind is not blowing?

A. It is likely that the Project's wind injections could raise the energy components in hours when the wind is not blowing. Because plants have different operating characteristics, it is possible that displacing the marginal generator when the wind is blowing means that the generator will not be available for dispatch in the next day. While the generator may have been marginal when the wind was blowing, it is likely that the same generator will be located in the stack well below the marginal unit in a high-demand hour. This concept is discussed in greater detail below regarding the impact of the Project on the integrated energy market operation.

Q. Based on Grain Belt Express' modeling, what are the combined impacts of the Missouri converter station and the Illinois/Indiana converter station on the energy component of the MISO LMP when the wind is blowing, and when it is not blowing?

A. Using Grain Belt Express' assumptions and LMP study,[19] the Missouri load payment for the energy component of the LMP would decrease by $7,959,565 in hours when

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[17] There is a benefit to the geographic diversity of wind that would be offered by the project, namely that wind in Kansas is not entirely coincident with wind in other states, particularly Iowa, Illinois, and Michigan.
[18] MISO 2013 State of the Market Report, page 5.
[19] Staff has not performed an independent analysis of the reasonableness of the assumptions used in the LMP study. In particular, Staff has not assessed the reasonableness of the following items (1) load assumptions for the year 2019, (2) generator capacities, efficiencies, dispatch stack, or bid amounts for the year 2019, (3) the wind delivery used for the year 2019, (4) the level of precision used in modeling factors such as generator heat rate curve, transmission loading curves, or other inputs to the PROMOD model.

the wind is blowing, and would increase by $904,335 in hours when the wind is not blowing.[20] This further demonstrates that there is great uncertainty related to the Project and the impact on Missouri's regulated utilities and retail ratepayers.

Q. What is the impact of the Missouri converter station on the LMP components at Palmyra, if run in isolation from the Illinois/Indiana converter station, as compared to Grain Belt Express's modeled LMP without the Project?

A. Running only the Missouri converter station in isolation increases the magnitude of all LMP components at Palmyra, on both total and per-MWh basis.

500 MW Mo Injection Totals				
	Full LMP	Energy	Congestion	Losses
No Project:	$ 67,801,252	$ 73,444,899	$ (83,578)	$ (5,560,069)
Total Project:	$ 65,847,132	$ 73,189,783	$(993,379)	$ (6,349,273)
Mo 500 only:	$ 73,202,517	$ 80,057,177	$(570,789)	$ (6,283,871)
500 @ MO 1000 only:	$ 72,955,497	$ 81,023,530	$(1,068,467)	$ (6,999,566)

500 MW Mo Injection per Injected MWh				
	Full LMP	Energy	Congestion	Losses
No Project:	$ 32.16	$ 34.84	$ (0.04)	$ (2.64)
Total Project:	$ 31.23	$ 34.71	$ (0.47)	$ (3.01)
Mo 500 only:	$ 34.72	$ 37.97	$ (0.27)	$ (2.98)
500 @ MO 1000 only:	$ 34.60	$ 38.43	$ (0.51)	$ (3.32)

Q. Which converter station has the greater impact on the energy component of the LMP at Palmyra that was modeled by Grain Belt Express?

A. Assuming no congestion, whichever converter station is delivering more energy in a given hour will have the greater impact on the energy component of the LMP. The energy component is the same at every node in MISO at a given interval. Additionally,

[20] Hours in which 100MW of wind was delivered to the Missouri converter station was used for determining whether the wind was blowing or not blowing. Using, for example, 20MW of Missouri wind delivery resulting in $7,176,225, and $121,025, respectively. Looking only at hours when 400MW or more of wind is delivered to the Missouri converter station results in a decrease of $4,116,816 during wind hours, and an increase of $2,938,414 during non-wind hours.

the MISO and the PJM operate an interchange designed to converge prices between these two markets. Given the size of the deliveries used in the Grain Belt Express model, the reductions to the energy component shown in the LMP results are only 1/8 attributable to the Missouri converter station. However, Grain Belt Express' results demonstrate that the Missouri converter station does have an impact on increasing the energy component of the LMPs experienced throughout the MISO, by increasing the level of congestion experienced in Missouri.

Q. How does congestion affect the energy component of the LMP?

A. Congestion causes the dispatch order to skip a generator in the generation stack. If a low-cost generator cannot get power to load because of a transmission constraint, the MISO market responds by skipping that generator and dispatching a more expensive generator, raising the energy cost for everyone in the footprint.

Q. What do Grain Belt Express' model results show about the impact of the Missouri converter on congestion in Missouri?

A. It shows that it increases congestion.

Q. How much does Missouri congestion increase with the Project as modeled?

A. While load-applied energy decreases only 0.223% ($7,055,023), congestion increases in magnitude by 312.817% ($11,855,309). For every MW of wind injected at the Missouri converter station, the value of the congestion component experienced at the Palmyra node increases $5.62, or a gross value of $11,855,309. However, the impact on reducing the energy costs of the entire Project including both injection sites is only $7,055,230. Essentially, the Project causes $11 million of uneconomic dispatch of energy to save $7 million.

Q. Is congestion economically and efficiently bad?

A. Yes.[21] Transmission congestion causes uneconomic dispatch. Uneconomic dispatch wastes fuel and fuel expense. As stated in the 2013 MISO State of the Market Report at page 50,

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources to establish efficient, location-specific prices that represent the marginal costs of serving load at each location. Transmission congestion arises when the lowest cost resources cannot be fully dispatched because transmission capability is limited. As a result, LMPs can vary substantially across the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load in order to avoid overloading transmission facilities. This causes LMPs to be higher in "constrained" locations.

Q. Will net reductions in wholesale power prices raise Missouri retail rates?

A. Grain Belt Express has not provided any information regarding the change in the fuel-efficiency of the eastern interconnection with and without the Project. Also, Grain Belt Express has not provided any information regarding the cost-efficiency of the eastern interconnection with and without the Project. This information is necessary to determine the impact on Missouri retail customers, in that it changes the average net energy costs for Missouri utilities.

Q. What impact will the Project have on the MISO load-share-allocated transmission and administrative expense for Ameren Missouri retail customers?

[21] Congestion are revenues paid to holders of Financial Transmission Rights ("FTRs") – per page "v" of 2013 State of the Market for MISO. This could provide an opportunity for additional revenue to Transmission Owners should MISO direct the construction of additional lines to alleviate the congestion caused by the Missouri converter. Some of the cost of those lines would likely be ultimately borne by Missouri retail ratepayers.

A. If the Project is and remains project funded, there should be no or minimal impact on Ameren-Missouri's load-share allocated costs. However, the Missouri converter station is modeled to create a great deal of congestion. If this congestion causes MISO to order the build-out of new projects to alleviate the congestion, there will be additional load-allocated costs. Since the purpose of building lines to minimize congestion would be to converge LMPs, the "benefit" of reduced Missouri wholesale prices will be mitigated by the existence of the new line, which Missouri ratepayers will ultimately pay for a significant portion.

Q. What additional study is necessary to address Staff's concerns with the Project's impact on integrated market pricing?

A. The same market studies described above concerning retail rate impact are necessary to better estimate the Project's impact on integrated market pricing.

Impact of the Project on the Integrated Energy Market Operation

Q. Have you reviewed Grain Belt Express' PROMOD analysis of the impact of both converter stations on generation dispatch in the Eastern Interconnect?

A. Yes.

Q. What limitations of Grain Belt Express' analysis should be kept in mind?

A. Regarding the method of analysis, the following factors limit the usefulness of assessing the impact of the Project:

1. Only a day-ahead analysis was performed, so there is no attempt to identify the generation resources necessary to accommodate real-time variation from dispatch order.
2. No analysis of ancillary services was performed.[22]
3. The day-ahead analysis appears to have been performed with flat hourly blocks of wind energy injection.
4. The quality of the data and the reasonableness of the inputs used for (1) load assumptions for the year 2019, (2) generator capacities, efficiencies, dispatch stack, or bid amounts for the year 2019, (3) the wind delivery used for the year 2019, (4) the level of

[22] Response to Staff Data Request 11.

precision used in modeling factors such as generator heat rate curve, transmission loading curves, or other inputs to the PROMOD model.

The first three limitations are related. While wind output can be predicted fairly accurately over time, it is difficult to predict wind output on an intra-hourly interval basis. The real-time variation and the regulation and ramping services necessary to accommodate wind energy injection are not considered in Grain Belt Express' analysis, which limits the utility of the modeling for estimating the impact of the Project on the economic efficiency and the environmental efficiency of the Eastern Interconnect, as well as Missouri retail rates.

Q. Are there also limitations to the usefulness of the output of Grain Belt Express' analysis?

A. Yes. Grain Belt Express did not include modeled wind or nuclear generation in the output provided in response to Staff Data Request 37. Also, Grain Belt Express did not provide plant dispatch by percent-owner, so it is difficult to quantify the precise impact on jointly-owned generating stations, particularly in instances where a percentage-owned asset is located outside of the state of Missouri.

Finally, in response to Staff Data Request 37 Grain Belt Express provided annual net impact of the converter stations, as opposed to the hourly generating outputs of the generating units. Grain Belt Express did not retain the hourly generating output from the PROMOD run for each generating asset. While this does not impact the accuracy of the modeling itself, it does limit the precision of the review I was able to perform. For these reasons, the percentages I provide below do not exactly reflect the state or owner discussed. For example, because Callaway nuclear generation was not included in Grain Belt Express' output, the total number of Missouri-generated kWh for the year 2019 is understated by that amount. Similarly, because The Empire District Electric Company does not own the entire Iatan generating station, the output of that station is excluded from the discussion of the impact on

Empire's generating fleet, and included entirely in Kansas City Power & Light Company's fleet.

Q. Per Grain Belt Express' modeling, by type of generating asset, what is the impact of the Project on net generation that is (1) owned by a Missouri investor-owned-utility in any state in any amount, (2) physically located in Missouri regardless of owner, and (3) not wind or nuclear?

A. Based on my review of Grain Belt Express' response to Staff Data Request 37, Grain Belt Express has modeled the impact of the Project on net generation to be:

This Table Is Deemed Highly Confidential In Its Entirety

Q. Per Grain Belt Express's modeling, by owner of generating asset, what is the impact of the Project on net generation that is (1) owned by a Missouri investor-owned-utility in its own name in any state and (2) not wind or nuclear?

A. Based on my review of Grain Belt Express's response to Staff Data Request 37, Grain Belt Express has modeled the impact of the Project on net generation to be:

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This Table Is Deemed Highly Confidential In Its Entirety

Q. Why does a given utility or asset type show both increases and decreases?

A. Grain Belt Express provided the results of its PROMOD run as the annual generation in MWh of each individual generating asset over the course of the year 2019 without the Project, and then provided the reduction (or increase) against that annual level of generation with the Project. A given generating asset at a given site may show an increase in annual output, while a similar unit at the same site with the same owner and fuel type may show a decrease in annual output.

Q. Are these results surprising for a day-ahead only analysis without ancillary services and where wind is modeled in flat block increments?

A. No.

Q. Are these results consistent with the dispatch you would expect after taking regulation and ramping ancillary services into account, as well as the real-time market?

A. No. In particular, I would expect the simple cycle combustion gas turbines to generate significantly more often. These resource types will be necessary to accommodate for real-time deviations in the amount of wind energy delivered into northeast Missouri, as well as to provide regulation and ramping services through the ancillary services markets.

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Q. How much simple cycle combustion turbine capacity is located in northeast Missouri?

A. To my knowledge, the most significant simple cycle combustion capacity site is the Ameren Missouri Audrain generating station. As modeled by Grain Belt Express, this site consists of eight simple cycle combustion turbine units, each with a 90 MW capacity. In its "Business as Usual" scenario *without* the Project, Grain Belt Express modeled this site to generate ** ____ ** MWh in the year 2019. In its "Business as Usual" scenario *with* the Project, Grain Belt Express modeled this site to generate ** ________ ** MWh in the year 2019.

Q. Is that result reasonable if ancillary services and real-time dispatch are incorporated into the modeling?

A. That result is not consistent with my expectations for a resource with significant ramping capability located near the injection of 500MW of wind energy. As noted above, Grain Belt Express did not attempt to incorporate ancillary services and real-time dispatch into its modeling.

Q. Is Staff concerned that there is not adequate ramping capacity currently available in northeast Missouri to accommodate the injection of 500MW of wind energy at the point selected by Grain Belt Express for the Palmyra converter station?

A. Yes. In its response to Staff Data Request 4, Robert Zavodil indicated on behalf of Grain Belt Express that "additional system flexibility (in the form of fast-ramping generation or another technology) may be needed to accommodate the wind generation injected by the Grain Belt Express Project." Although Grain Belt Express did not quantify the additional ramping capacity that may be needed in northeast Missouri, the response did indicate that 16 MW would be needed for the Ameren Missouri territory in general. Staff

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would expect the amount that would need to be physically located in the already-constrained area around the converter station's planned location to be some greater amount.

Q. Per Grain Belt Express's modeling, by type of generating asset, what is the impact of the Project on net generation that is (1) located anywhere in the Eastern Interconnect, and (2) not wind or nuclear?

A. Based on my review of Grain Belt Express's response to Staff Data Request 37, Grain Belt Express has modeled the impact of the Project on net generation to be:

This Table

Is Deemed

Highly Confidential

In Its Entirety

Q. Per Grain Belt Express's modeling, by physical location of generating asset, what is the impact of the Project on net generation that is (1) physically located in each of the states in which Grain Belt Express seeks authority regarding the Grain Belt Express Project, and (2) not wind or nuclear?

A. Based on my review of Grain Belt Express's response to Staff Data Request 37, Grain Belt Express has modeled the impact of the Project on net generation to be:

This Table Is Deemed Highly Confidential In Its Entirety

Q. Per Grain Belt Express's modeling, were there any units that Grain Belt Express modeled to run in 2014 without the Project, but modeled not to run at all with the Project?

A. ** ____

____

____ **

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Highly Confidential Table Below

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Q. Per Grain Belt Express's modeling, were there any units that Grain Belt Express modeled to run in 2014 without the Project, but modeled to run 50% – 99% less with the Project?

A. ** ____ **

Q. Per Grain Belt Express's modeling, were there any units that Grain Belt Express modeled to run more than 50% more in 2014 with the Project than without the Project?

A. ** ____ **

Q. Which generating assets experienced the greatest gross reduction in annual generation with the addition of the Project?

A. The units experiencing more than 100,000 MWH reductions to annual generation are provided by type, state, capacity, modeled generation, and percent change in Schedule SLK-6. ** ____ **

Q. Are these results consistent with the changes to dispatch you would expect considering only the day-ahead market, without ancillary services, and using flat block wind injections?

A. Generally.[23]

Q. Do the existing load conditions, generation mix, and transmission system throughout the Eastern Interconnect impact the ability of a given point on the transmission system to efficiently accept the injection of wind energy.

A. Yes. In addition to the ramping and regulating concerns for simple cycle gas turbine capacity described above, there is also a concern that some of the most efficient units in the Eastern Interconnect's generation fleet may not be able to run efficiently if the location of wind injection is not carefully chosen.

Q. Are some generation types more compatible with wind generation than others?

A. Yes. If an area is largely dependent on simple cycle CTs for generation, it is my understanding that wind integration requires little or no additional infrastructure, and the impact to the generation stack results in dispatch that is not only cost effective in virtually all hours, but also that improves the efficiency of the fleet in terms of achieving the most output energy from the least input fuel. The quick dispatchability and excellent ramping properties of a CT make it very attractive from a market perspective, particularly in regard to providing ancillary services such as regulating reserves and spinning reserves.

Q. Are some generation types less compatible with wind generation than others?

A. Yes. "Baseload" thermal units, such as nuclear, coal, and some types of combined cycle gas units are designed to efficiently run with a relatively stable output around the clock, and may take days or weeks – up to a month – to turn off and on. Bearing in mind that load tends to require more energy during the day than at night, and more energy in

[23] Were these other factors considered, I would expect the simple cycle combustion gas turbines to generate significantly more often. These resource types will be necessary to accommodate for real-time deviations in the amount of wind energy delivered into northeast Missouri, as well as to provide regulation and ramping services through the ancillary services markets.

summer and winter than in spring or fall, baseload thermal units already tend to produce enough energy at night than areas with a high percentage of generation from thermal units will see noticeably lower nighttime LMPs than daytime LMPs, even in the absence of wind. Adding wind to the generation mix exacerbates this price disparity, which would be expected to result in one of two outcomes:

1. The thermal unit will be displaced from the generation stack. A less cost-efficient simple cycle CT will be run during the day and the wind will be accommodated during the night.
2. The thermal unit will be run outside of its most efficient loading. Since most thermal units are designed to run optimally between – for example – 70% to 90% loading, the unit may be backed down to – for example – 50% loading by night to accommodate the wind energy, and ramp to run at 90% loading by day when demand is greater and prices are higher. This could result in nearly as much thermal fuel being used as if the wind energy was not injected; but if the generating capacity is needed during the day it will be necessary to keep the unit running low or spinning overnight.

Q. Given the location and fuel type of changes to annual generation output modeled by Grain Belt Express, do you expect that congestion is causing more efficient generation assets to be displaced from the generation stack in favor of less-efficient generation?

A. Yes.

Q. Please briefly summarize the ultimate impact of all the data you have analyzed and discussed throughout your testimony thus far and how this data (whether directly in Missouri or at another point along the Project) will affect Missouri investor-owned utilities and Missouri ratepayers.

A. Wind integration requires careful consideration of many factors, including load requirements, the strengths and weaknesses of the existing generation fleet, existing transmission constraints, and transmission constraints that will be created by the wind integration. While there are real benefits to successfully integrating wind energy into a system, it is important to be cognizant of the impact of that wind integration on the operational and economic efficiency of the involved systems.

Q. Are the concerns discussed in this testimony alleviated or aggravated if the Missouri converter station is used to facilitate an injection of 1000MW of wind energy?

A. The concerns, particularly regarding the need of regulating/ramping capacity and the impact of increased congestion would more than double if the Missouri converter station is used to facilitate an injection of 1000MW of wind energy. The generation stack's cost curve is shaped like a backwards "L." Bid prices increase slowly through much of the capacity, but much more quickly as the stack's capacity becomes used.

Q. If the infrastructure described in the Application were operated in a different manner than the manner described in the Application, would the impact on Missouri ratepayers' retail bills be the same?

A. Probably not. If the converter station were used to flow power out of Missouri during hours when the wind is not blowing – into either SPP or PJM – it is probable that the impact on Missouri retail rates would be very different.

Q. What is the relevance of the impact of the Project as described in the Application to the Commission's determination of public interest under the Tartan criteria in *In Re Entergy Arkansas Inc.*, File No. EA-2012-0321, Order Granting Certificate of Convenience and Necessity (July 11, 2012), citing *In Re Tartan Energy Co.*, 3 Mo.P.S.C.3d 173, Case No. GA-94-127, Report and Order (1994)?

A. To the extent that Cleanline has held out this project as described in the Application as accruing to the public interest by reducing Missouri ratepayers' retail bills, the evidence provided to date does not support such conclusion.

Q. What additional study is necessary to address Staff's concerns with the Project's impact on integrated market operation?

A. The same market studies described above concerning retail rate impact are necessary to better estimate the Project's impact on integrated market pricing. Particularly, to determine whether an impact more favorable to Missouri retail rates could be achieved by the infrastructure described in the Application but operated differently, Grain Belt Express must analyze the net impact to Missouri utilities of picking up Missouri energy by day for export to PJM or SPP. Also, Grain Belt Express should study whether the variability of the injected wind could be better managed in the SPP prior to injection.

Centralized Transmission Planning

Q. You previously stated that other certificate cases included information related to information that involved RTO/ISOs. What is the purpose of RTOs?

A. FERC's Order 2000 and Order 2000-A identified the minimum functions of an RTO, which include the function of transmission system Planning and Expansion.

Q. Is Grain Belt Express's Application the result of RTO-coordinated planning and expansion?

A. No. Other certificate requests involved lines where some regional entity had determined that a particular project was necessary to improve one or more aspect of regional transmission operation; sought input from stakeholders regarding the sizing, design, and location of the project; studied and optimized the sizing, building, and location of the project; solicited a builder for the project; and had a plan from the outset for the project's use. Staff is particularly concerned that the normal work product of an RTO's Planning and Expansion functions of RTOs is not available for the benefit of the Commission's review of the Application.[24]

Q. What requirements must an RTO satisfy regarding planning and expansion?

A. As stated at page 485 of FERC's Order 2000

> We reaffirm the NOPR proposal that the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities. In carrying out this overall responsibility, the Commission has concluded that the NOPR's three separate requirements for RTO planning and expansion must also be satisfied or, in the alternative, the RTO must demonstrate that an alternative proposal is consistent with or superior to these three requirements. Specifically, an RTO must satisfy the requirement to: (1) **encourage market-motivated operating and investment actions for preventing and relieving congestion**; (2) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary; and (3) file a plan with the Commission with specified milestones that will ensure that it meets the overall planning and expansion requirement no later than three years after initial operation, if the RTO is unable to satisfy this requirement when it commences operation. [emphasis added]

Q. Why is the RTO's role in encouraging market-motivated operating and investment actions for preventing and relieving congestion noted?

A. Based on Staff's review of the Application, it appears that Grain Belt Express's request would increase congestion in Missouri. As discussed above, Staff is concerned that Grain Belt Express's Application creates a congestion problem that MISO will be obligated to attempt to resolve. The cost of the resolution of that congestion problem should be considered in evaluating the costs and benefits of the Application.

[24] Staff is also concerned with the implications of the Application will exacerbate future need for further congestion management mitigation projects, and complicate future interregional coordination issues. These issues, as well as the probable need for additional ancillary services are discussed in earlier sections of this testimony.

Q. Have the other transmission line certificates the Commission has approved more broadly considered the congestion creation and alleviation of the subject line or portfolio?

A. Yes, as discussed below.

Q. What is MISO's regional planning process?

A. In summary, as provided from MISO's frequently asked questions:

> RTO planning functions include the provision of long-term Transmission Service, Interconnection Service, and regional planning. These services are provided collaboratively with member TOs, consistent with the Transmission Owners Agreement. MISO is registered with NERC as a Planning Authority and, as such, fully evaluates and plans for the reliability of the transmission system in accordance with NERC's planning standards. MISO develops an annual regional expansion plan based on expected use patterns and analysis of the performance of the transmission system in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions.
>
> This analysis and planning process integrates into the development of the regional plan among other things:
>
> - Transmission needs identified from Facilities Studies carried out in connection with specific transmission service requests.
> - Transmission needs associated with generator interconnection service.
> - Transmission needs identified by the Transmission Owners in connection with their planning analyses in accordance with local planning processes to provide reliable power supply to their connected load customers and to expand trading opportunities, better integrate the grid and alleviate congestion.
> - Transmission planning obligations of a Transmission Owner imposed by federal or state laws or regulatory authorities.
> - Plans and analyses developed by the Transmission Provider to provide for a reliable transmission system and to expand trading opportunities, better integrate the grid and alleviate congestion.
> - Identification, evaluation, and analysis of expansions to enable the transmission system to fully support the simultaneous feasibility of all Stage 1A ARRs.
> - Inputs from the Planning Advisory Committee.
> - Inputs, if any, provided from state regulatory authorities having jurisdiction over any of the Transmission Owners and by the Organization of MISO States.
>
> The development of the regional plan is undertaken in an open and transparent planning process as prescribed by FERC Order 890, which provides multiple opportunities for all stakeholders to review and provide

input into the plan. These FERC planning principles also require close inter-regional planning coordination with neighboring systems and are accomplished via the joint operating agreements included as rate schedules to the MISO Tariff. Periodic inter-regional plans are developed that ensure that the systems of MISO members are not negatively impacted by the planning decisions of nearby entities.

Planning for the reliable interconnection of new generation, of both affiliated and independent power producers is provided for by MISO as the Transmission Provider. System impact and Facilities Studies are conducted collaboratively with the impacted Transmission Owners and adhere to the local planning criteria of those owners, as well as to national and regional planning criteria under the NERC umbrella.[25]

Q. What is SPP's regional planning process?

A. In summary, as provided from SPP's frequently asked questions:

What is SPP's role in transmission planning?

One of SPP's responsibilities as a FERC-approved Regional Transmission Organization is to create regional transmission expansion plans. SPP doesn't build or own transmission; we work with our members to create planning models and studies to determine new transmission that will be needed to maintain reliability and provide economic benefit into the future. SPP can assess needs from a larger, regional perspective rather than the more limited view of a single utility. In the regional planning process, each new transmission project is part of an integrated whole. While each project has unique characteristics, it is the combination of projects that creates regional benefits.

According to SPP's Open Access Transmission Tariff, the Transmission Owners whose substations connect to the beginning or end of the planned lines have the right of first obligation to build the projects. SPP does not establish rates for recovery of transmission project costs, nor have we historically played a significant role in developing project cost estimates; instead, we have compiled and presented cost estimates developed by Transmission Owners. SPP does track project construction, including estimates and actual costs.

SPP's studies indicate that transmission is needed between Point A and Point B to meet planning objectives such as maintaining reliable operations, addressing congestion, and providing economic benefits. The exact route to achieve this needed transmission is determined by the utility and state regulators (when required).

The responsibilities of all stakeholders in the process must be understood: SPP to provide a transparent regional transmission planning

[25] Available at:
https://www misoenergy.org/Library/Repository/Communication%20Material/About%20Us_FAQ/Transmission PlanningFAQ.pdf.

process, Transmission Owners to construct and own transmission facilities, and FERC/state regulatory authorities to regulate within their statutory authority.

Q. Have both RTO's developed transmission plans specifically related to wind integration?

A. Yes. MISO states that its "Mulit-Value Projects" ("MVP") portfolio "will deliver reliability, public policy and economic benefits across the system. MISO's energy zones are designed to optimize wind generation placement and to minimize distance to other fuel sources such as natural gas. When connected to the overall grid by the MVP projects, the zones will enable access to low-cost energy for the entire MISO footprint."[26]

MISO states that its "Value Proposition" reflects that its "continued efforts in regional planning enables more economic placement of wind resources in the region. Economic placement of wind resources reduces overall capacity needed to meet required wind energy output. MISO's regional planning results in a wind integration benefit of $256 to $297 million."[27]

SPP describes its "Integrated Transmission Planning Process" as "an iterative three-year process that includes 20-Year, 10-Year, and Near-Term Assessments. The process seeks to target a reasonable balance between long-term transmission investment and congestion costs to customers. The ITP will create synergies by integrating three existing processes: the Extra High Voltage Overlay, the Balanced Portfolio, and the SPP Transmission Expansion Plan Reliability Assessment. By integrating these processes, additional efficiencies are expected to be realized in the Generation Interconnection and Aggregate Transmission Service Request study processes. The ITP will work in concert with SPP's existing sub-

[26] See Schedule SLK-7, MISO "One-pager on MVPs."
[27] See Schedule SLK-8, MISO "One-pager on Value Proposition."

regional planning stakeholder process, and will continue in parallel with the NERC TPL Reliability Standards compliance process."

SPP's Balanced Portfolio is premised on SPP's conclusion that "[s]avings are realized when transmission upgrades reduce congestion on SPP's transmission system, thus lowering generation production costs. Economic upgrades may provide other benefits to the power grid such as increasing reliability, lowering required reserve margins, deferring reliability upgrades, lowering end-use consumer costs, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources."[28]

Q. Has the Commission awarded a CCN for any projects that are part of a MISO regional transmission plan?

A. Yes. The Lutesville to Heritage line certificate awarded after evidence was received that MISO had included the project in its regional transmission plan. Issued in Case No. EA-2013-0089, this certificate involved an approximately fourteen mile 345,000-volt electric transmission line. Approximately six miles of the proposed transmission line is not within Ameren Missouri's current certificated service area.[29]

"The transmission line is part of a larger project that includes the construction of a new substation, the Heritage Substation, located west of the city of Cape Girardeau, and upgrades to the existing Lutesville, Wedekind, and Cape Girardeau substations. In addition, the project includes construction of approximately 2 miles of a 161,000-volt line."[30]

"This project is required to meet [Ameren Missouri]'s transmission needs and ensure reliability to the region, and is part of a regional transmission plan approved by the Midwest Independent Transmission System Operator, Inc. ("MISO"). Specifically, this project will

[28] See Schedule SLK-9, SPP "Balanced Portfolio."
[29] See *Order Granting Certificate of Convenience and Necessity*, effective May 4, 2003, in Case No. EA-2013-0089.
[30] See *Application*, at page 2, in Case No. EA-2013-0089.

prevent voltage collapse that could result in an outage to over 320 megawatts ("MW") of load in the Cape Girardeau area, in the event of certain transmission outages occurring at the time of peak demand. Under the applicable criteria for North American Electric Reliability Corporation ("NERC") Category C contingency events, Ameren Missouri is required to take corrective action to address this problem."[31]

"The estimated cost for this transmission line, including the portions inside and outside of Ameren Missouri's currently certificated service territory is $55-$75 million."[32]

Q. Were the Iatan-Nashua and Sibley-Nebraska City transmission projects, Case No. EA-2013-0098, part of an SPP regional plan?

A. Yes. As stated in the *Report and Order*, effective September 6, 2013, in that case at page 12, "there is a need for the service to be rendered by the Projects based upon studies performed by SPP in 2009 and 2010. These studies demonstrated that the Projects will improve electric grid reliability, minimize transmission congestion effects, bring economic benefits to SPP members, and help support public policy goals regarding renewable energy. The studies also demonstrated that the Projects will provide estimated benefits and savings that exceed the Projects' estimated costs."

As stated in the *Joint Memorandum in Support of Stipulation*, filed June 6, 2013, those parties stated that "there is a need for the service to be rendered by the Projects based upon studies performed by SPP in 2009 and 2010. These studies demonstrated that the Projects will improve electric grid reliability, minimize transmission congestion effects, bring economic benefits to SPP members, and help support public policy goals regarding renewable energy. The studies also demonstrated that the Projects will provide estimated benefits and savings that exceed the Projects' estimated costs. See SPP Balanced Portfolio Report (June 23, 2009),

[31] See *Application*, at page 2-3, in Case No. EA-2013-0089.
[32] See *Application*, at page 3, in Case No. EA-2013-0089.

attached as Ex. 6 to the CCN Application; SPP Priority Projects Phase II Final Report (Apr. 27, 2010), attached as Ex. 11 to the CCN Application."[33]

The scope of these lines is described in a compliance filing in Case No. EA-2013-0098 as "The Midwest Transmission Project (a.k.a, the Sibley-Nebraska City Project) is a regional transmission project that involves the construction of a new single circuit 345kV transmission line in northwest Missouri and southeast Nebraska extending approximately 180 miles from the substation located at Omaha Public Power District's ("OPPD") Nebraska City generating station to a new intermediate 345kV substation near Maryville, Missouri, and continuing on to the substation located at KCP&L Greater Missouri Operations Company's ("GMO") Sibley generating station. The new 345kV substation, which has been named Mullin Creek Substation, will include reactive resources for voltage control and provide a potential interconnection point for new renewable generation resources.[34]

"The portion of the Midwest Transmission Project in Missouri consists of the new Mullin Creek Substation and a total of approximately 135 miles of transmission line both from GMO's Sibley generating station to Mullin Creek Substation and from Mullin Creek Substation to the interception point at the Missouri-Nebraska state line. The portion of the Midwest Transmission Project in Nebraska consists of approximately 45 miles of transmission line from the interception point at the Missouri-Nebraska state line to OPPD's Nebraska City generating station." [35]

"The Sibley-Nebraska City Project is identified as a Priority Project in the April 27, 2010 Southwest Power Pool, Inc.1 ("SPP") Priority Projects Phase II Final Report2. The SPP Board of Directors approved the Priority Projects, and SPP issued Notifications to Construct

[33] Footnote 4, at page 3, of the *Joint Memorandum in Support of Stipulation*, filed June 6, 2013, in Case Nos. EA-2013-0098 and EO-2012-0367.
[34] *Q4 Report, February 12, 2014, Midwest Transmission Project Quarterly Report, EA-2013-0098*, at page 1.
[35] *Q4 Report, February 12, 2014, Midwest Transmission Project Quarterly Report, EA-2013-0098*, at page 1.

("NTCs") for the Sibley-Nebraska City Project to GMO and OPPD to be Designated Transmission Owners ("DTOs") for the Missouri and Nebraska portions of the Project, respectively. SPP issued the NTC to GMO on July 23, 2010, and GMO accepted on September 28, 2010."[36] (per Q4 2013 Report)

Q. Is Grain Belt Express's requested interconnection with the transmission systems under functional control of MISO and SPP subject to the approval of the respective RTO?

A. Absolutely. Staff is not concerned that the RTOs would allow interconnection that would result in thermal overload of the respective transmission systems. Rather, Staff's concern is that while prior applications have been provided with evidence that the relevant project will affirmatively help the impacted transmission system, not only is such evidence absent from this Application, as discussed by Staff witness Shawn Lange, Grain Belt Express has not yet presented sufficient evidence that the Application would not result in thermal overload.

Q. Is a prior determination of "need" from an RTO or similar body sufficient for the Missouri Commission to find "need"?

A. That question can't be answered in the abstract. However, the Tartan criteria include a determination of need, among determinations of public interest, economic feasibility, financial ability, and qualified to provide the proposed service.

Q. Does Staff recommend that conditions be imposed on any authorization of Grain Belt Express' receipt of a CCN to build and operate the Project as described in the testimony of Staff witness Dan Beck?

[36] *Q4 Report, February 12, 2014, Midwest Transmission Project Quarterly Report, EA-2013-0098*, at page 1.

A. Yes. Staff witness Dan I. Beck is presenting all of Staff's recommended conditions in his rebuttal testimony. Some of those conditions are that certain items be completed. Others are that certain items be brought back to the Commission for Commission approval (or acceptance) prior to any condemnation of Missouri real property. Staff and other parties to this case should be given an opportunity for review and comment on these items requiring Commission approval (or acceptance). Q. Which of Staff's recommended conditions are you sponsoring?

A. Regarding retail rate impact on Missouri customers of investor-owned utilities, I recommend that the Commission order Grain Belt Express to perform a number of studies and to provide for Commission approval in compliance with the Tartan Criteria and other applicable law, the following items:

1. Production modeling that incorporates:
    - Day Ahead market prices to serve load,
    - Real Time market prices to serve load,
    - Ancillary Services prices to serve load,[37]
    - Day Ahead market prices realized by Missouri-owned or located generation,
    - Real Time market prices realized by Missouri-owned or located generation,
    - Ancillary Services prices realized by Missouri-owned or located generation,
    - An estimate of the impact of Grain Belt Express's Proposal on the operational efficiency of Missouri-owned or located generation.
2. Production, transmission, and economic modeling or analysis to determine:
    - The cost of transmission upgrades that may be economical to resolve the transmission constraints that its energy injections will cause or exacerbate.
    - The impact of using the entire design capacity of the Missouri Converter station.
    - The net impact to Missouri utilities of picking up Missouri energy by day for export to PJM or SPP.
    - Whether the variability of the injected wind could be better managed in the SPP prior to injection.

Staff recommends that the Commission order Grain Belt Express to provide to the Commission documentation of:

[37] Modeling for the Real Time and Ancillary Services markets should be based on a more reasonable wind shape that varies within the hour.

1. Grain Belt Express commitment that it will not seek RTO cost allocation for the Project itself, nor for any transmission system upgrades necessary to safely accommodate the Project.
2. Grain Belt Express commitment to utilize only the studied portion of the Missouri Converter station.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Sarah L. Kliethermes

MoPSC Employment Experience

Regulatory Economist III (July 2013 – Present)
Economic Analysis Section, Energy Unit, Tariff, Safety, Economic and Engineering Analysis Department of the Missouri Public Service Commission. In this position my duties include providing analysis and recommendations in the areas of RTO and ISO transmission, rate design, class cost of service, tariff compliance and design, and energy efficiency mechanism and tariff design. I also continue to provide legal advice and assistance regarding generating station and environmental control construction audits and electric utility regulatory depreciation.

My prior positions in the Commission's General Counsel's Office, which was reorganized as the Staff Counsel's Office, consisted of leading major rate case litigation and settlement and presenting Staff's position to the Commission, and providing legal advice and assistance primarily in the areas of depreciation, cost of service, class cost of service, rate design, tariff issues, resource planning, accounting authority orders, construction audits, rulemakings and workshops, fuel adjustment clauses, document management and retention, and customer complaints. Those positions were:
Senior Counsel (September 2011 – July 2013)
Associate Counsel (September 2009 – September 2011)
Legal Counsel (September 2007 – September 2009)
Legal Intern (May 2006 – September 2007)

Testimony

Contributor to Staff recommendation concerning KCP&L Greater Missouri Operations Company's Application for a Renewable Energy Standard Rate Adjustment Mechanism, in Case No. EO-2014-0151, addressing issues of customer notice and tariff design.

Rebuttal, regarding DSIM tariff design, margin rate calculation, and customer-related issues, in Case No. ER-2014-0095, Kansas City Power & Light application under the Missouri Energy Efficiency Investment Act. Case resolved by stipulation.

Provided at hearing, as well as prefiled Rebuttal and Surrebuttal, regarding average wholesale energy prices, in Case No. EC-2014-0224, Noranda Aluminum, Inc., et al., Complainants, v. Union Electric Company d/b/a Ameren Missouri, Respondent.

Contributor to Staff Report, regarding a requested Certificate of Convenience and Necessity, a requested Special Contract tariff sheet, and tariff review, in Case No. HR-2014-0066, In the Matter of Veolia Energy Kansas City, Inc for Authority to File Tariffs to Increase Rates.

Contributor to Staff recommendation concerning Ameren Missouri municipal lighting, in Case No. EC-2014-0316, City of O'Fallon, Missouri, and City of Ballwin, Missouri, Complainants v. Union Electric Company d/b/a Ameren Missouri, Respondent.

RELATED TRAINING

Presented *Ratemaking Basics* (Sept. 14, 2012).

Attended:

Electricity Energy Storage Sources (August 29, 2014)
Combined Heat & Power: Planning, Design and Operation (August 11, 2014)
Today's U.S. Electric Power Industry, the Smart Grid, ISO Markets & Wholesale Power Transactions (July 29-30, 2014)
MISO Markets & Settlements Training for OMS and ERSC Commissioners & Staff (Jan. 27 – 28, 2014)
Validating Settlement Charges in New SPP Integrated Marketplace (July 22, 2013)
PSC Transmission Training (May 14 – 16, 2013)
Grid School (March 4 – 7, 2013)
Specialized Technical Training - Electric Transmission (April 18 – 19, 2012)
Legal Practice Before the Missouri Public Service Commission (Sept. 1, 2011)
Renewable Energy Finance Forum (Sept. 29 – Oct 3, 2010)
The New Energy Markets: Technologies, Differentials and Dependencies (June 16, 2011)
Mid-American Regulatory Conference Annual Meeting (June 5 – 8, 2011)
Utility Basics (Oct. 14 – 19, 2007)

EDUCATION

Studying Economics at Columbia College, Jefferson City campus and online (2013 – Present)
Studying Energy Transmission at Bismarck State University, online (2014 – Present)

Licensed to Practice Law in Missouri, MoBar # 60024 (Summer 2007).
Juris Doctorate, University of Missouri, Columbia, Missouri (2004 – 2007).
Bachelor of Science in Historic Preservation, Cum Laude, minor in Architectural Design, Southeast Missouri State University, Cape Girardeau, Missouri (2002 – 2004).
2000 – 2002: Studied Architecture and English Literature at Drury University, Springfield, Missouri.

OTHER EMPLOYMENT EXPERIENCE

Law Clerk, Contracting and Organization Research Institute. Performed legal research; analyzed, described, and categorized contracts.

Paid Intern, Southeast Missouri State University. Accessioned and organized artifact collections for the Missouri Department of Natural Resources, Division of State Parks and Historic Sites.

Intermediate Clerk, Missouri Department of Elementary and Secondary Education. Responsibilities included organizing and managing various forms of data.

Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts

Technical Report
NREL/TP-550-46275
July 2009

Michael Milligan and Brendan Kirby

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Prepared under Task No. WER95501

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Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts

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Abstract

Wind variability and uncertainty cause an increase in power system operating costs as increasing amounts of wind generation are incorporated into the power generation mix. Accurately calculating these costs is important so that wind generation can be fairly compared with alternative generation technologies. Methods for calculating wind integration costs have matured over the last few years with the incorporation of mesoscale wind modeling, time-synchronized load data, and full power system simulation, including security constrained unit commitment and economic dispatch. All methods calculate wind integration costs by comparing total power system costs with and without wind generation. A simple comparison of the with- and without-wind costs is not sufficient, however, because the value of the wind energy itself is also included in this difference. In order to remove the energy value bias and calculate only the wind integration cost, current methods substitute an energy proxy into the base case. Unfortunately, it is difficult to craft an energy schedule that can be placed into the base case that does not have significant capacity and/or differential energy value itself. A flat block of energy, for example, is the equivalent of firm energy with 100% capacity value, something no wind plant claims to be able to supply. This paper explores the issue by first articulating the problem and showing the cost impacts through examples. The authors then examine various alternative base energy schedules which mitigate the energy and capacity value bias and allow for more accurate calculation of the wind integration cost.

Introduction

Over the past several years, there has been substantial progress in understanding the impact that wind energy has on power system operation and costs (Smith, et. al., 2007). Because of wind's variability and uncertainty, there has been widespread interest in quantifying the increase in ancillary services required to integrate wind over various time scales. Wind generally causes a small increase in the amount of regulating capacity needed for system balance. In the sub-hourly load following time frame which typically encompasses time periods of several minutes to a few hours, wind's impact is more substantial. It is widely accepted that the increase in variability that wind brings to the system has a cost on system operation, resulting from increased cycling from intermediate and possibly peaking units, along with an increase in flexibility reserves that are needed to manage the system.

While the scope and sophistication of wind integration studies has increased substantially, methods to estimate integration cost for wind often result in the mixing of value and cost. This arises because of the proxy resource assumptions that are often used in the reference case with no wind. In this paper, we explore this issue by first developing a simple example, and applying prices from the Midwest Independent System Operator (MISO). We also investigate the impact on ramping of various proxy resources, and then look at some alternative proxy resources proposed by EnerNex as part of the Eastern Wind Integration and Transmission Study (EWITS).

Wind Integration Cost

Wind integration cost studies over the past few years have attempted to capture the impact and costs that wind's variability and uncertainty bring to bulk power system operation. It is generally acknowledged that these costs fall into the various time scales associated with system operations: regulation, load following, and unit commitment and scheduling, as Figure 1 illustrates. The impact of wind energy on the regulation time scale is generally well-understood. Those impacts are relatively easy to calculate when synchronized high-resolution load and wind data are available. Because regulation is a capacity service, calculating wind's incremental contribution to regulation requirements does not interfere with the energy accounting. As we will see shortly, the energy accounting and its side effects are surprisingly difficult to handle in a wind integration cost study.

The load following time frame generally covers periods from 5-10 minutes to a few hours.[1] The unit commitment time frame, sometimes called the scheduling period, ranges from several hours to several days, depending on the type of generator and its cycling characteristics. It is in these time frames that wind generation tends to have the largest impact on operations.

When thermal generating units cycle more often as a result of adding wind to the generating portfolio, there is typically a decrease in unit efficiency that arises as a result of the more frequent ramping, and because units may be operated at less efficient points on their heat rate curve.[2] The increase in cycling can cause wear and tear, which can be captured by quantifying operations and maintenance cost that is caused by the wind-induced cycling.

[1] The exception is that in many parts of the Western Interconnection of North America, energy markets operate hourly. In those cases, regulating units balance all variation within the hour. This is not only very expensive, but it limits the amount of flexibility that can be obtained from the generation fleet. When longer regulation time scales apply, the regulation service will also include an energy component which is not present in the typical regulation time scale.
[2] Thermal units can be required to cycle more often when new baseload generation is added as well.

In the scheduling time frame, it is likely that imperfect information about wind forecasts will cause errors in the optimal commitment schedules, which normally have a cost. For example, if the wind forecast is too low, more conventional generation may be committed than needed, causing an additional system cost both in terms of start-up and the fuel and variable O&M costs incurred by running at a sub-optimal operating level. Conversely, if the wind forecast is too high, insufficient thermal generation may be committed than is needed, requiring the use of more expensive combustion turbines in real-time.

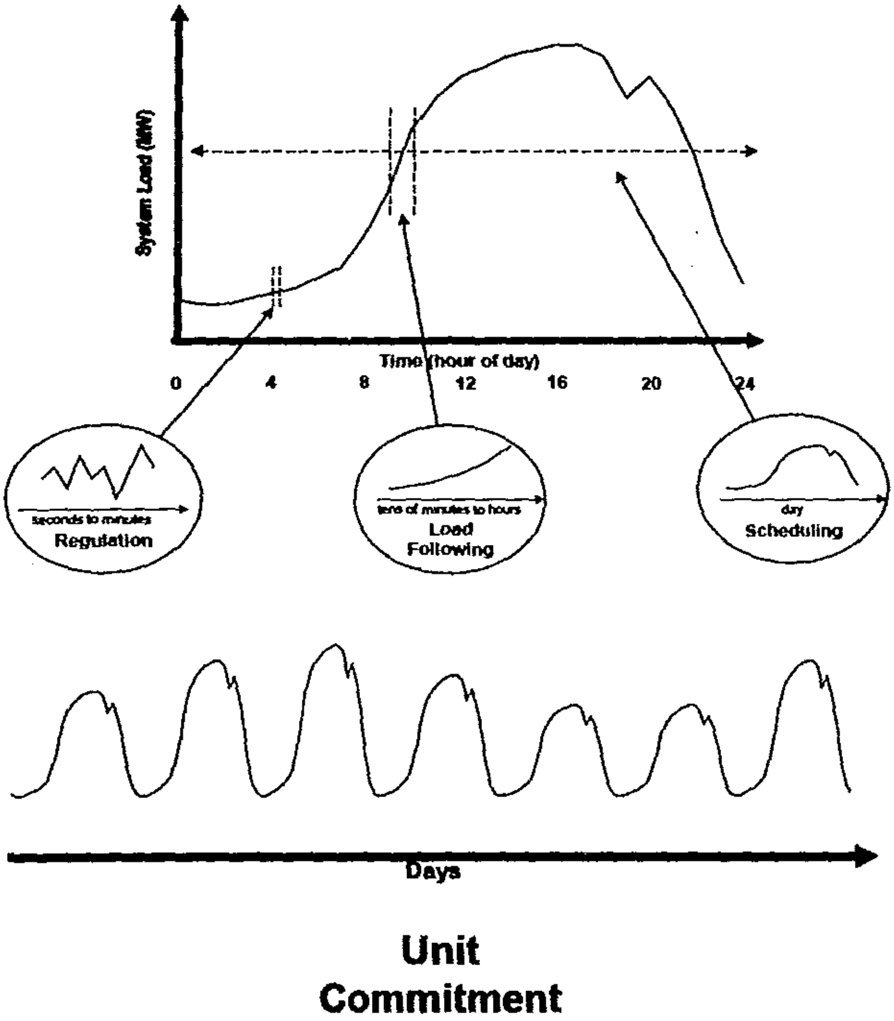

Figure 1. Time scales for power system operation.

Adding wind to the power system causes some units to operate less often than in the no-wind case. The type of fuel displaced will vary by system, and will also depend on the specific unit operating on the margin. Even for a given utility, the marginal fuel may be coal during some hours and gas during others. Adding wind may also result in less committed capacity during some periods of time. The reduction in fuel and the potential reduction in unit commitment schedules have an economic value that can be estimated with appropriate production simulation modeling. Using the same modeling framework, the reduction in emissions and any associated value can also be captured. Although they are more difficult to capture, the risks associated with fuel (availability, price, or both) and emission can be calculated as well.

Wind integration cost studies typically address the cost of operating the conventional generation under the increased variability and uncertainty that are introduced by wind generators. However, when wind is added, additional low-cost energy is supplied above and beyond the no-wind case. To account for the potential energy bias of comparing cases with additional energy sources in the generation mix, a base case is typically constructed as the reference.

Because the objective of a wind integration cost study is to capture the impact and cost of wind's variability and uncertainty, the base case commonly includes a proxy resource that adds no additional variability or uncertainty to the resource mix. This proxy resource delivers a daily-equivalent flat energy block, based on the wind energy. Using this daily flat energy block in the base case, the power system is simulated for at least one year in hourly time steps, and the electricity production cost is noted. A second simulation case is run after replacing the flat energy block with the wind "as-delivered." The difference in production cost between these cases is interpreted as one component of the integration cost. Although there are typically other cases that are run with varying degrees of wind forecast accuracy that can help estimate the cost of uncertainty, we will not discuss those in this paper (see Table 1).

Table 1. Integration cost is calculated as the difference between simulation runs.

	Steps to calculate wind integration cost
1	Convert wind energy profile into a series of 365 daily flat energy-blocks
2	Run the production simulation model and record the production cost
3	Re-run the simulation, replacing the flat block with wind "as delivered"
4	The difference between costs in steps 2 and 3 is the integration cost

If wind were not added to the system, there are clearly many alternative ways to deliver the energy that wind would have delivered. For example, in systems with significant natural gas generation on the margin, wind would displace gas, and perhaps some other fuel. In that case, one could argue that the no-wind case should use the wind-displaced natural gas, since that is the alternative to wind. Alternatively, the load serving entity (LSE) may be considering a contract to purchase energy as an alternative to wind. Again, one could argue that the wind case should be compared to the energy purchase case to determine the integration cost of wind.

Although there may be many other alternatives to comparing wind and non-wind cases, most non-wind generation alternatives will be dispatched and will therefore ramp to some extent, given the type of unit and operational constraints. As a comparison alternative for a no-wind simulation case, use of a proxy generator was not thought to provide a good benchmark since additional variability would be introduced to the system. This led to the development of the daily flat energy block as the proxy unit: such a unit adds energy, but does not add any variability or uncertainty within the day. The caveat to this is that an inter-day ramp was introduced, but at low to moderate wind penetration levels, this was generally insignificant.

The flat proxy resource appears to have an unintended consequence, however, in the assessment of the system operational cost. In step 2 of Table 1, we see that the system is simulated with the proxy resource. In the next step, the proxy is removed and the wind is added to the model "as-delivered." The no-wind case therefore introduces additional energy into the system. Since the energy for this resource is available as a flat block throughout the day, part of that energy is available during peak periods during which prices are generally higher than average. But for the wind case, more energy is often delivered during off-peak periods when energy prices are lower. Consequently, the differential between the simulations will introduce a difference in *energy value*, as distinct from an *integration cost*. To explore whether this is a significant issue, we set up a series of test cases. The results and discussion of these cases appears in the sections below.

Simple example: separating value from cost

We used 3 years of hourly wind production data taken from the Minnesota 20% Wind Integration Study (EnerNex, 2006), along with locational marginal prices (LMP) obtained from the MISO. We used wind data from 2003, 2004, and 2005 from the Numerical Weather Prediction (NWP) modeling phase of the study, and LMPs from 2008. Unfortunately, we were unable to find LMP and wind data from the same year, so that implies that our results are only indicative. However, our findings indicate that there may be a significant value component that is unintentionally embedded in wind integration costs that are calculated using a daily flat block reference.

To reinforce our basic argument, we first show the average daily profile from the 2004 wind data and the LMPs in Figure 2. Wind production can be seen to drop on average during the day, whereas energy prices generally rise in the early morning and drop off in the evening. From an aggregate annual perspective, the implication appears to be that the value of the wind energy would be somewhat less than an energy-equivalent resource that delivers a constant amount of energy during the day. We now walk through the development of a simple example to provide the context for our evaluation of the potential value differential between wind energy and the daily flat-block proxy resource.

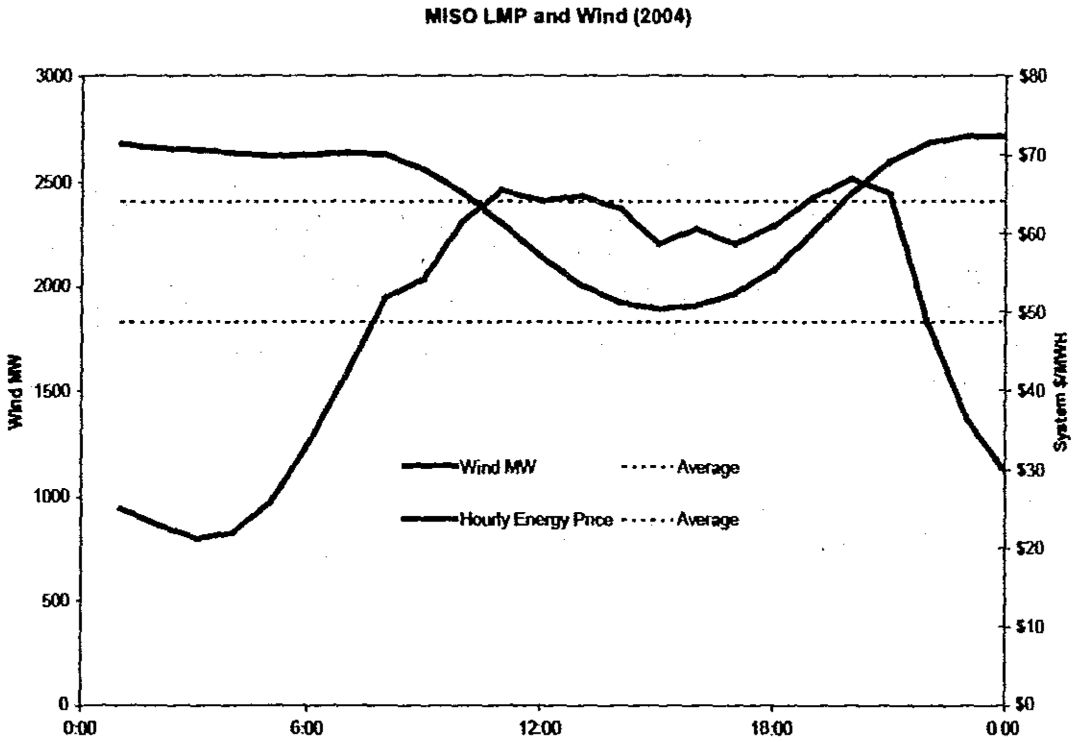

Figure 2. Prices and wind power production generally follow different diurnal patterns.

We use data from the Minnesota 20% Wind Integration Study as the basis for our discussion and example calculations. To simplify the discussion, we abstract from the actual resource stack, and assume that there is sufficient generation within the state-wide balancing area to cover loads plus contingency reserves. This simplistic generalization does not have any material impact on our results or analysis. Most of the graphics we show are intended to illustrate the process, and are based on the first week of the year. However, our analysis covers one year of wind data and three years of energy price data.

Figure 3 shows our base case situation. The available generation is sufficient to cover the load plus a 7% reserve margin as shown in the upper panel. Because there is excess generation that is not committed in this first week of January for this summer-peaking system, the lower panel shows the *potential* energy sales that could be made. The shape of this curve clearly shows the diurnal pattern of the excess generation, which tends to be higher at night and lower during the day.

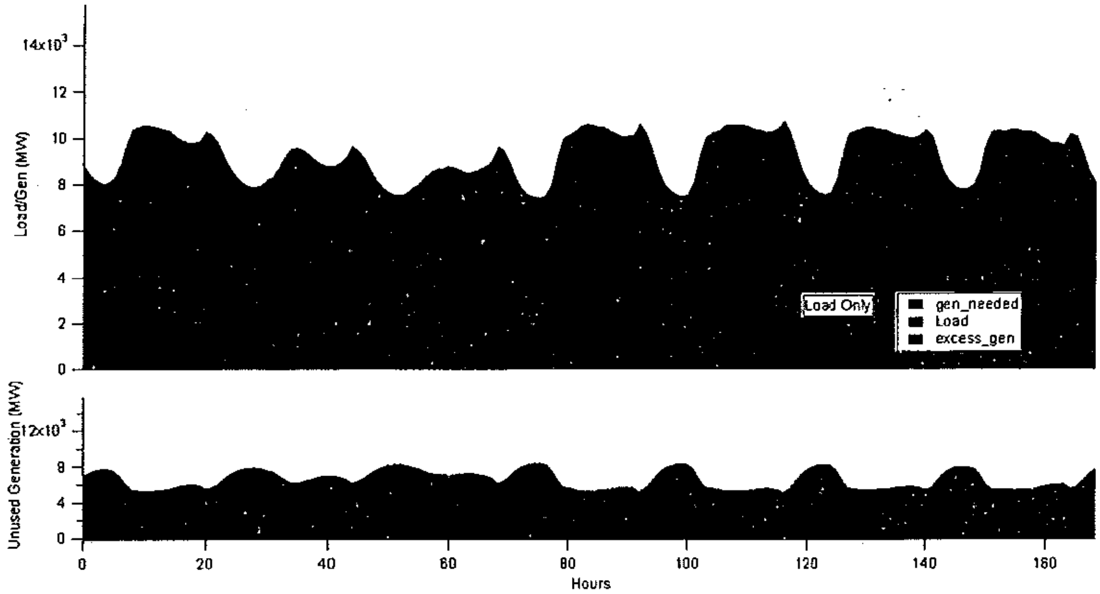

Figure 3. One week of load and generation data for our simple example.

When wind is introduced into the resource mix, this adds an additional opportunity to increase sales. This increase in potential sales appears in the lower panel of Figure 4, but can perhaps be more clearly discerned by comparing the upper panels of Figure 3 and Figure 4. To obtain a closer look, we can observe the difference in Figure 5. We stress that the energy sales opportunities in both cases are potential, and may not occur if there is insufficient demand from outside the balancing area or if this energy is not price-competitive with other energy that may be offered for sale by others.

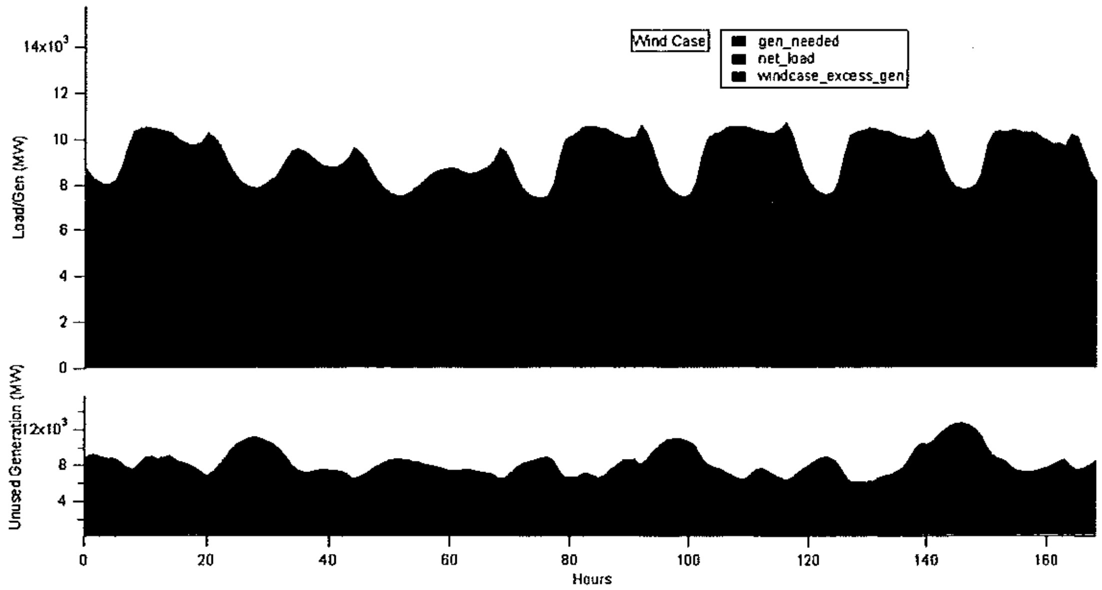

Figure 4. When wind is added to the generation mix, potential sales opportunities increase.

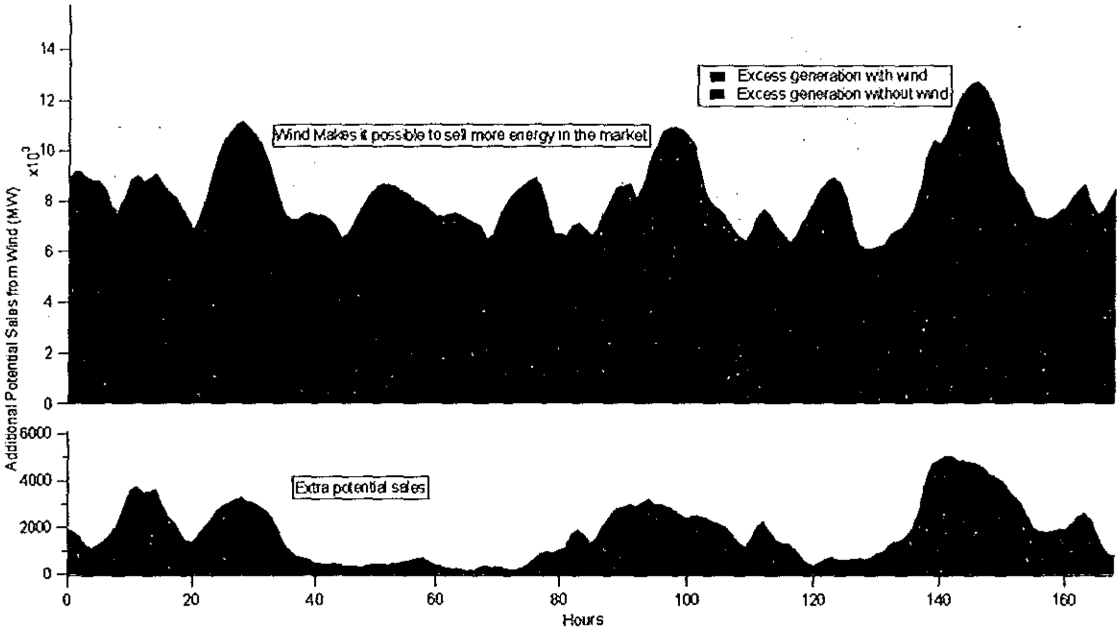

Figure 5. Comparison of potential energy sales for the no-wind and wind cases.

We now turn to a comparison of the market value of wind and the value of the flat block proxy. In our analysis, we assume that wind does not have any impact on market prices. This simplifying assumption may not be valid for high wind penetrations, especially when periods of high wind energy production coincide with low-load periods. We discuss the implication of this issue later in the paper, but they tend to increase rather than decrease the concern with the flat block proxy.

The typically proxy resource, an energy-equivalent flat energy block for the day, is represented in Figure 6. The annual value of the proxy resource is \$48.82/MWh. Figure 7 shows the market price, wind energy production, and wind energy value for the same time period. The annual wind energy value is \$47.36/MWh. There is clearly a difference in the value with the flat energy block being worth \$1.46/MWh more, on average, than the wind energy, as delivered.

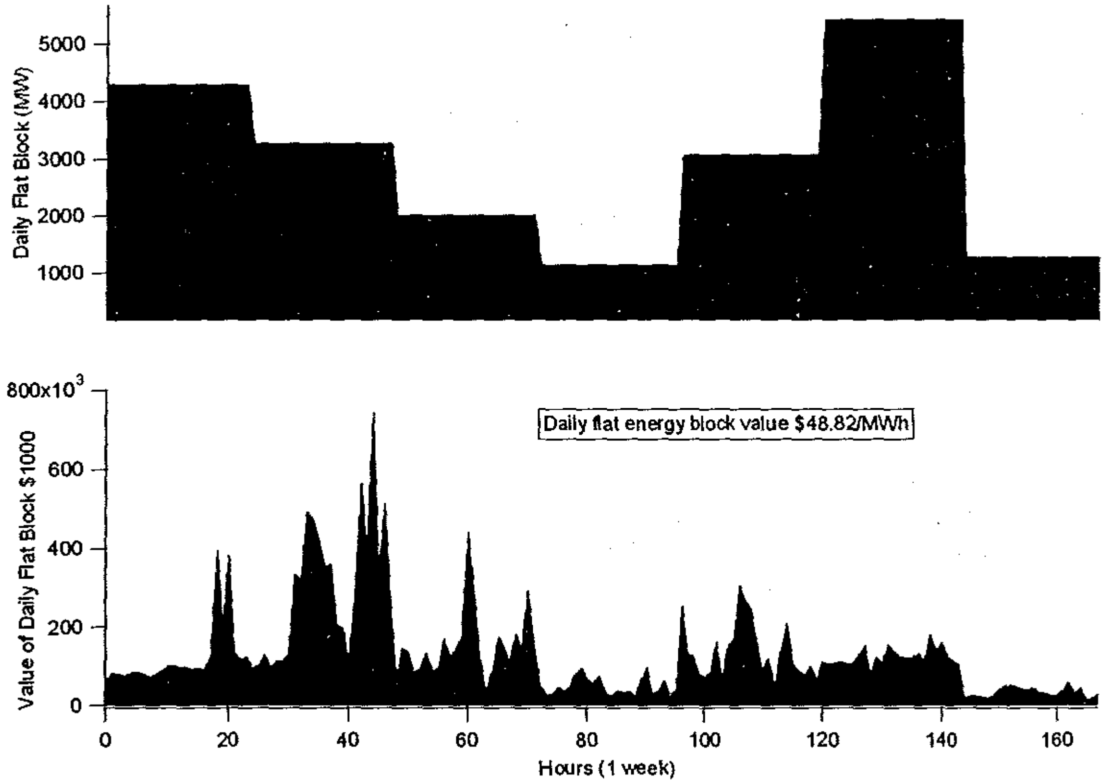

Figure 6. One week of the daily flat energy block and market value. The annual market value of the flat block is $48.82/MWh.

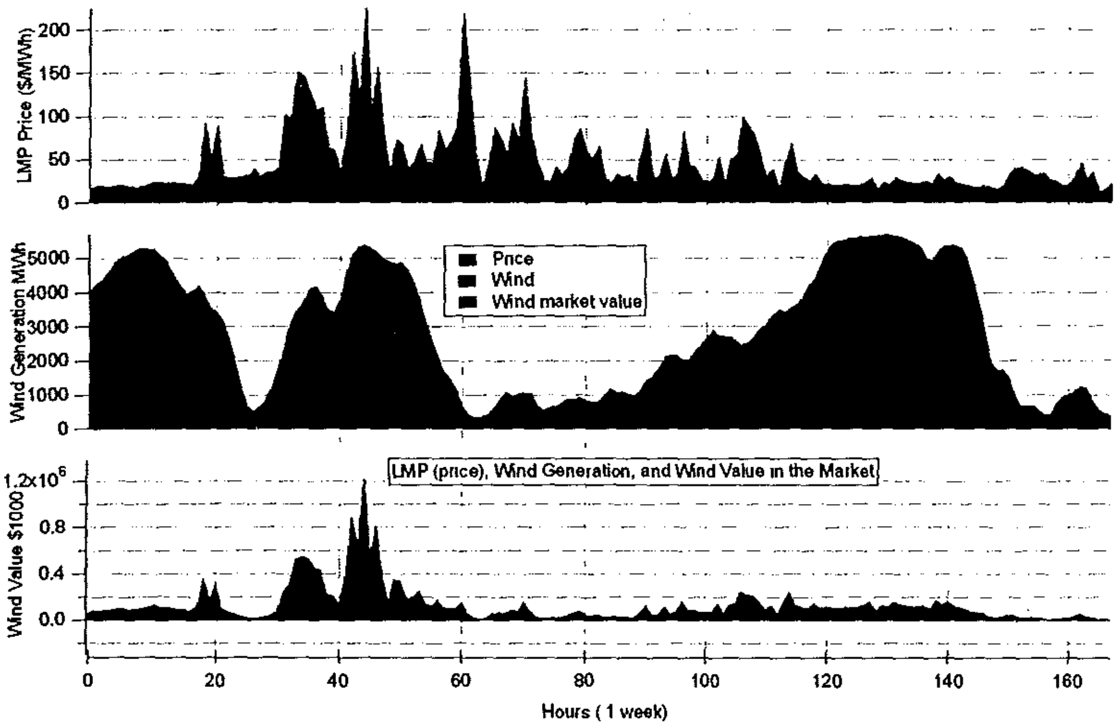

Figure 7. One week of market price, wind energy, and wind market value. Annual wind value is $47.36/MWh.

Because the daily flat block cannot distinguish between high-price and low-price periods, which tend to cycle by time of day, we performed a simple comparison of the daily flat energy-block value to the value of a 6-hour block. As might be expected, the 6-hour flat block more closely matches the wind than does the daily flat block. Figure 8 provides an example. The upper panel shows the daily block, along with the hourly wind generation and hourly LMP. In the lower panel, the wind and LMP traces are replicated for convenience, and the 6-hour flat block replaces the daily block.

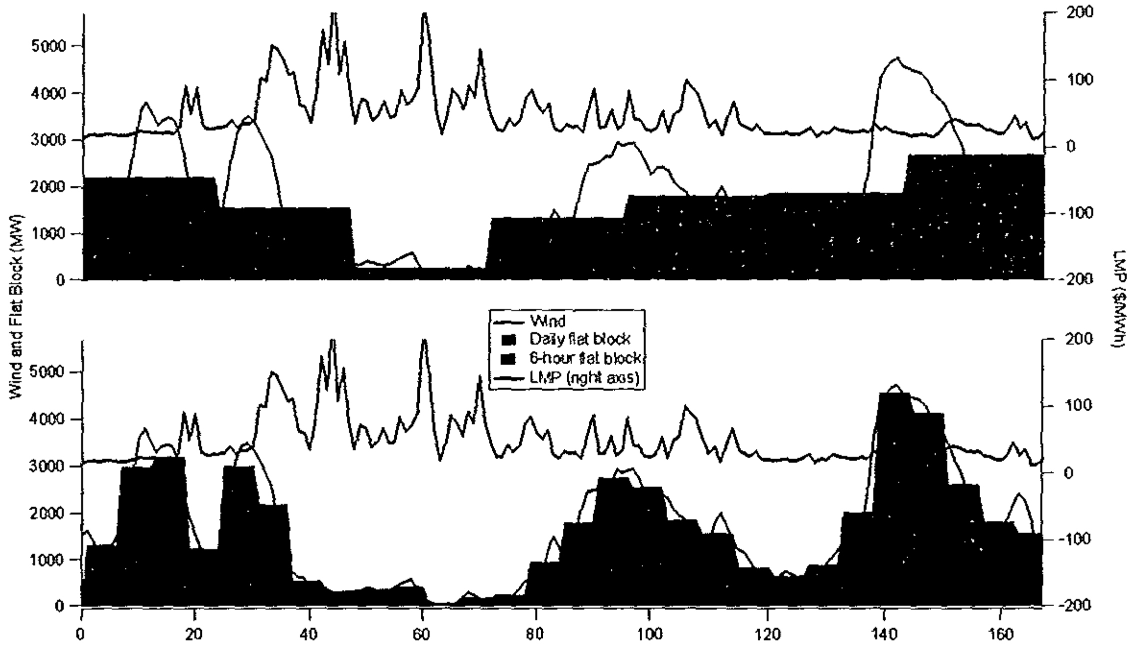

Figure 8. The 6-hour flat block does a better job of approximating wind energy value than the daily block.

The comparative values are displayed in Figure 9. In both panels, the red line (scale to the right) indicates the divergence of the block's value from the wind value. The graph shows that the divergence of value varies considerably by hour, but for the full year of 2004 the daily block is $1.46/MWh higher than the wind value, whereas the 6-hour flat block is only $0.23/MWh higher than the wind value.

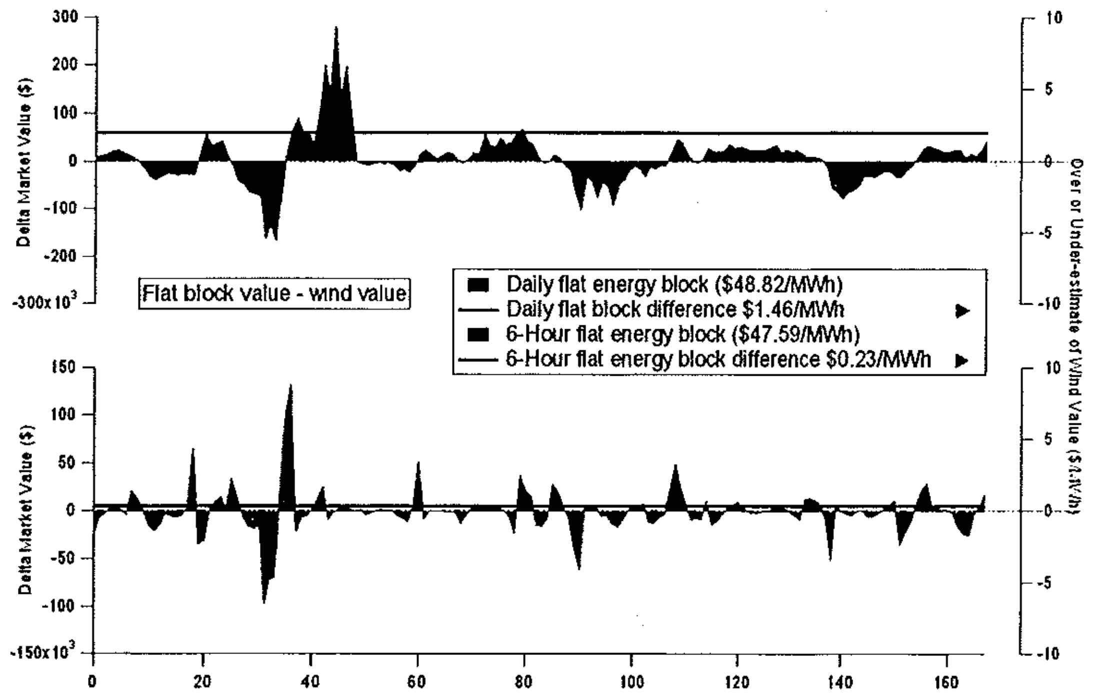

Figure 9. The 6-hour flat block comes closer to estimating wind's value than the daily flat block.

This result also applies to the three years of wind data we analyzed. In all cases, the 6-hour block value came closer than the daily block value. Figure 10 shows these results as differences from the wind case. For example in 2003 the daily block value is nearly $2.00/MWh more than the wind value, but the 6-hour block is $0.23/MWh higher in value than the wind. Examining the average profiles for the 3-year wind data set alongside the average LMP profile in Figure 11 shows that the basic relationship of the diurnal wind profiles to LMP does not change significantly from year to year.

Discussion and Caveats

Given that our LMP and wind data come from different years, we believe our results to be illustrative of the fact that the differential energy value of a daily flat block compared to wind energy is inadvertently included in the integration cost, as measured in several wind integration cost studies. Our particular numerical results are significant in the sense that they illustrate the magnitude of the problem, but they should not be treated as precise estimates of the value differential.

It is important to stress the caveats to this analysis. First, we assume that wind is a perfect price-taker in the energy market. Under this assumption, wind has no influence or impact on LMP. Although this is likely true at low penetration rates when transmission congestion is not an issue, it does not hold in cases of very high wind penetration or significant congestion. Evidence from large-scale integration studies (for example California Energy Commission, 2007)shows that wind can cause market prices to fall at high penetrations. The potential sensitivity of LMP to wind injections should only provide a wider spread to the value differentials we have identified.

The wind and price data in our analysis comes from different years. As can be seen in Figure 11, the average diurnal profiles of wind do not appear to vary significantly in comparison to the LMP profile. We expect our results are indicative of the value differential between wind and daily flat energy blocks, but are not precise. We also expect that the value differentials would likely vary for different utilities and markets, and different wind penetrations.

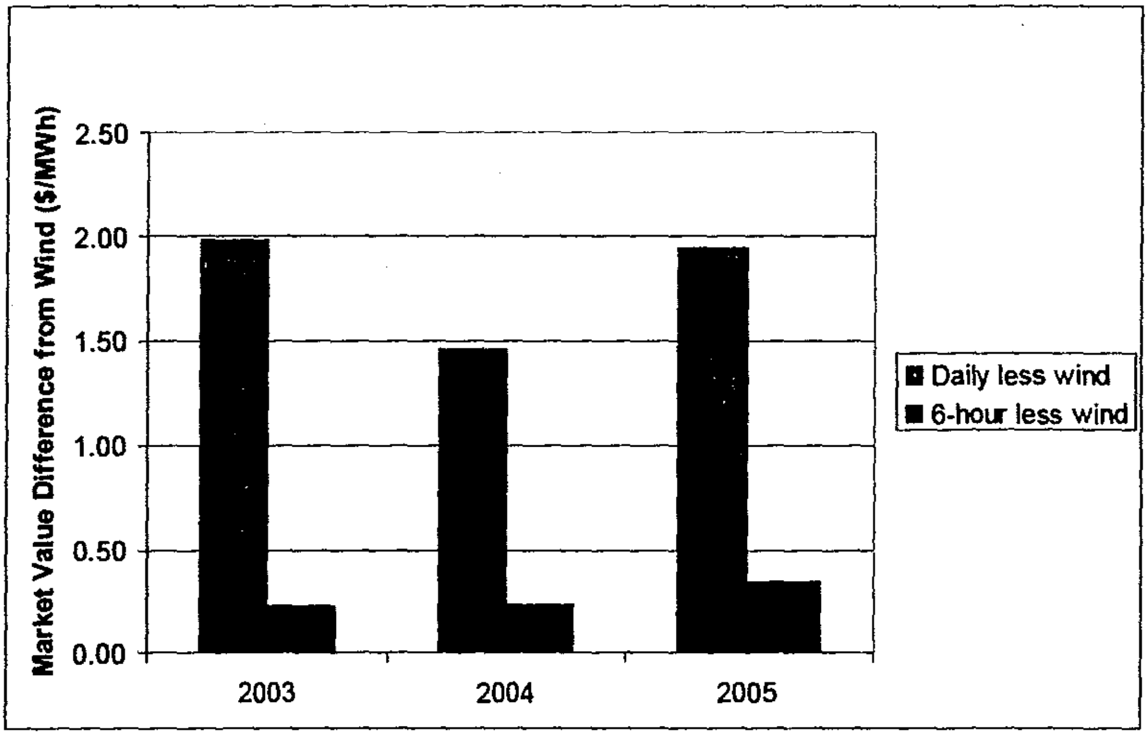

Figure 10. 3-year results summary.

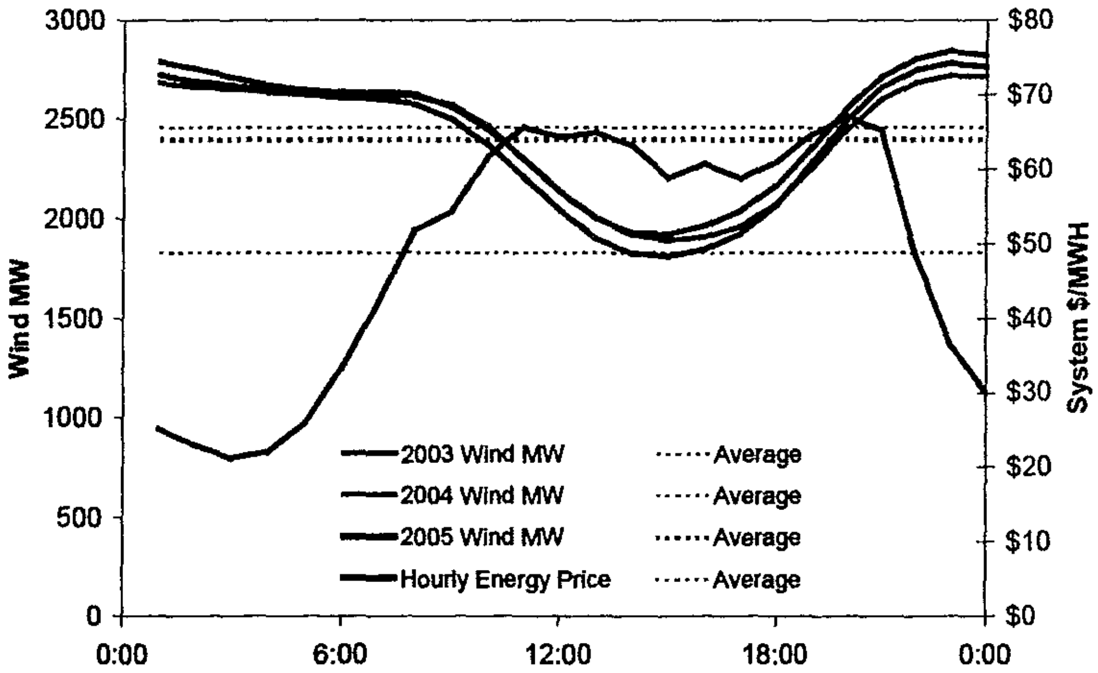

Figure 11. The relationship between wind and LMP profiles does not change significantly based on our data.

Implications for integration costs

Bearing in mind the caveats of the previous section, we describe the implication of these findings on selected wind integration cost results. Table 2 shows how our results would change integration cost results. For the illustration and to emphasize that our results are not precise, we use $1.50/MWh throughout, which is slightly higher than our minimum value differential of $1.46/MWh but less than the 3-year average differential of $1.80/MWh. When the value differential of the proxy resource is subtracted from the integration cost, it is clear there is a substantial difference. Using our low estimate of $1.50/MWh for the value differential, it is apparent that the value differential ranges from about 30%-40% of the originally-calculated integration cost. If the average differential of $1.80/MWh is used instead, the maximum percentage is as high as 48%.

Table 2. Impact of the value differential on selected integration cost results (for illustration only)

Date	Study	Integration cost from study ($/MWh of wind)	Block Value (estimated) ($/MWh, daily energy)	Revised Integration cost ($/MWh of wind)
Sep 2004	Xcel MN/DOC	4.60	1.50	**3.10**
Apr 2006	Xcel/PSCo 10% Cap	3.72	1.50	**2.22**
	Xcel/PSCo 15% Cap	4.97	1.50	**3.47**
Dec 2006	MN 25% (energy)	4.41	1.50	**2.91**

Ramping Behavior of the Proxy Resource

The objective of using a proxy resource for wind integration analysis is to have a comparison resource that is benign, and therefore does not impose additional ramping requirements on the system. Short of using an annual flat energy block as a proxy resource, which has a value differential of $1.38/MWh for 2004, other flat block configurations do have ramp requirements when moving from one block to another. For example, the daily block will have a ramp at each new day that equals the difference in the average wind generation inter-day. The 6-hour block has a ramp four times a day. Examples of these ramps can be observed in Figure 8 for our sample week. The ramp is the transition between blocks in the graph.

Using the wind data from 2004, we calculated ramp duration curves. Because many of the ramps are small, we focus on the extreme ramps; those ramps at the tails of the cumulative distribution curve. We note that wind up-ramps can be curtailed if they impose a reliability risk or extreme costs. Since there is a limited number of potential daily block ramps, the up-ramp duration curve falls to zero fairly quickly, but achieves a maximum that is more than double the maximum wind up-ramp. The 6-hour block ramp is not as severe as the daily block, but is nearly double that of the wind. Figure 13 illustrates a similar behavior of down-ramps.

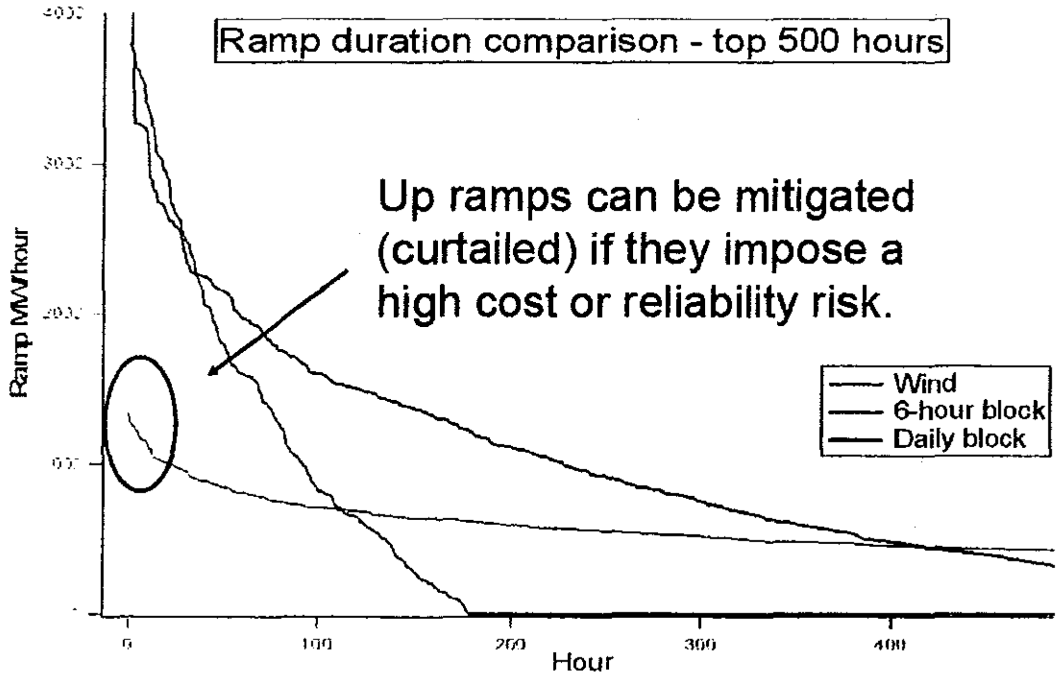

Figure 12. Extreme up-ramps from the flat blocks exceed wind ramps.

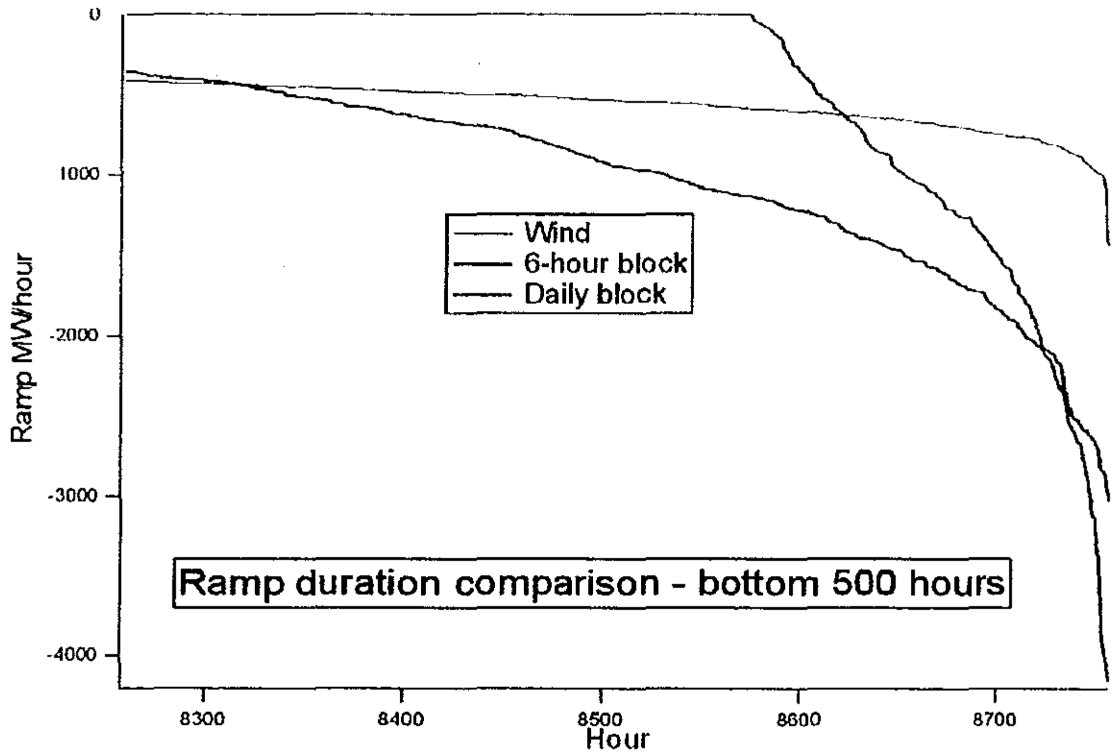

Figure 13. Extreme down-ramps from the flat block exceed wind ramps.

Case Study: Eastern Wind Integration and Transmission Study

The National Renewable Energy Laboratory is currently managing a large-scale wind integration study known as the Eastern Wind Integration and Transmission Study (EWITS). The study is sponsored by the U.S. Department of Energy, and is coordinated with the Joint Coordinated System Plan (www.jcspstudy.org) analysis that is hosted by the MISO. The study examines the impact of several wind build-out scenarios that achieve a 20% energy penetration within the study footprint, shown in Figure 14. One scenario examines a 30% wind energy penetration. In some of the early modeling work for EWITS that was carried out by teams at Ventyx and EnerNex, very large inter-day ramps were found in the daily flat-block proxy modeling cases. As a result, the project team spent some time discussing the issue and examining alternative approaches. Although it is premature to discuss specific findings of the EWITS analysis since work is ongoing, we include some discussion surrounding the proxy resource and additional alternatives.[3]

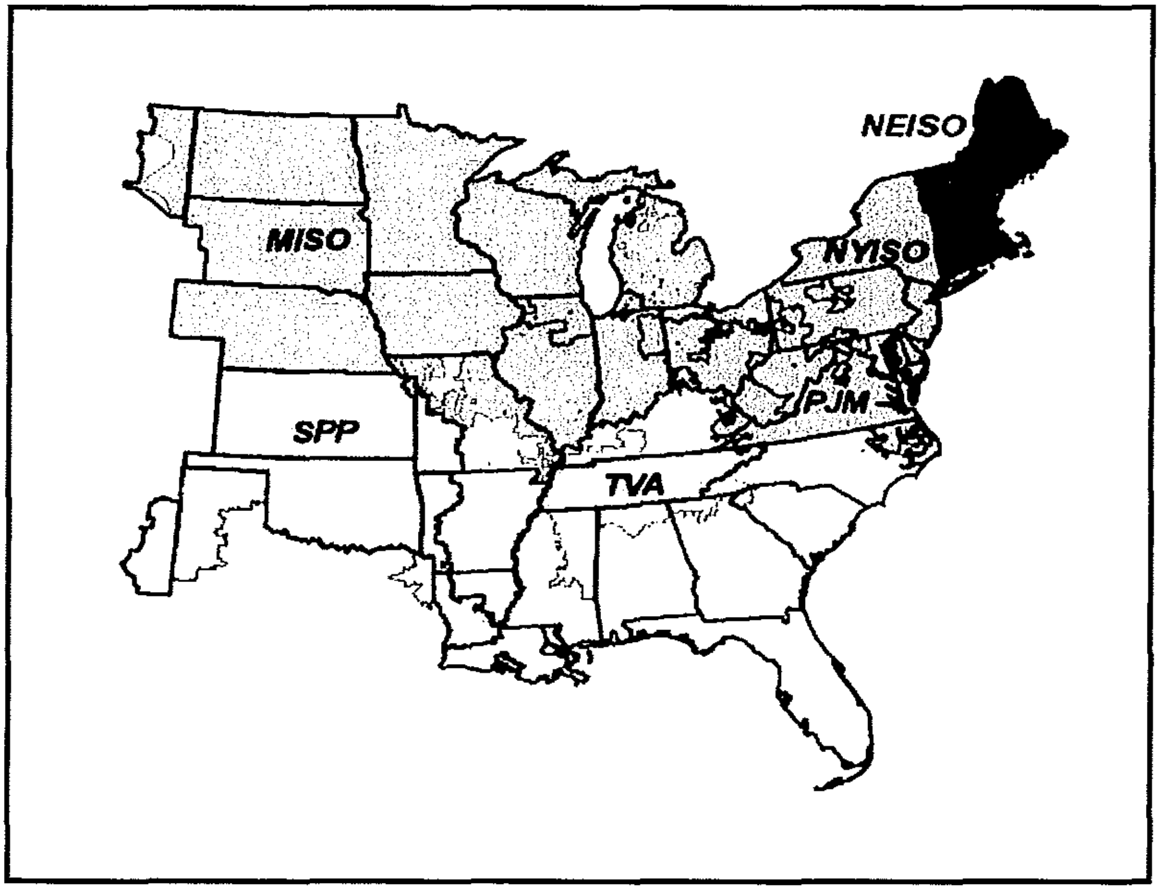

Figure 14. Footprint of the Eastern Wind Integration and Transmission Study.

[3] Thanks to Jack King, EnerNex, for providing data and processing.

To address the large inter-day ramps imposed by the daily flat block proxy resource, several alternatives were suggested. These include the 6-hour flat block, along with rolling averages of 24, 48, 96, and 168 hours (one week), respectively. In addition, a 3-year flat block was tested since that has no ramp characteristic at all. Using wind data from 2004-2006 and LMPs from 2008, as before, we analyzed the market value of wind energy and each of these alternative proxy resources. While the rolling average proxy methods do eliminate the inter-day ramping concerns, we found little difference in the market value of all of the rolling average proxies and the daily flat block. The 6-hour fixed block was the closest to wind of all proxy resources we examined. The 3-year flat block commanded a higher value than any of the alternatives. The results are presented graphically in Figure 15, which also shows the market value differential of each of the proxy resources. In most cases, the differential is approximately $1.70/MWh of wind, although the 3-year block value is more than $2.00/MWh higher than wind.

We also show ramp duration curves for selected proxy resources: daily block, and 24-hour moving average. Figure 16 shows that most ramps are within a range of plus-minus 4,000 MW/hour. We stress that the wind scenario represents approximately 300,000 MW of installed wind capacity across most of the footprint of the Eastern Interconnection, so 4,000 MW/hour is not excessive. However, we are more interested in the extreme ramp impacts. Figure 17 zooms in on the left side of Figure 16 and shows that the daily block nearly triples the maximum up-ramp compared to wind in the 3-year data set. The 24-hour moving average appears much more benign, and is potentially of interest as a proxy resource if the market value can be properly accounted for in integration analyses. The down-ramp characteristics of these proxies and wind are nearly symmetrical.

Figure 18 re-scales the 24-hour moving average ramp duration, and shows that the maximum and minimum ramps are 2,284 and -2,261 MW/hour, respectively.

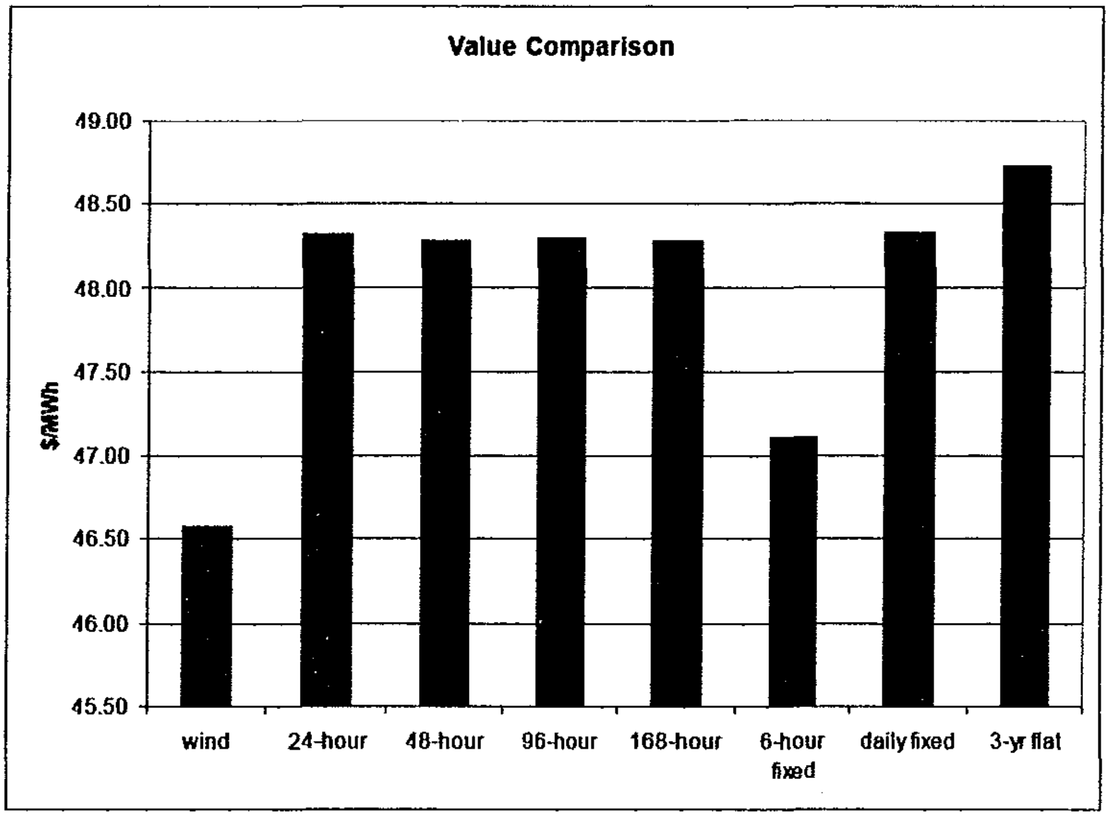

Figure 15. Market value and differential value of alternative proxy resources.

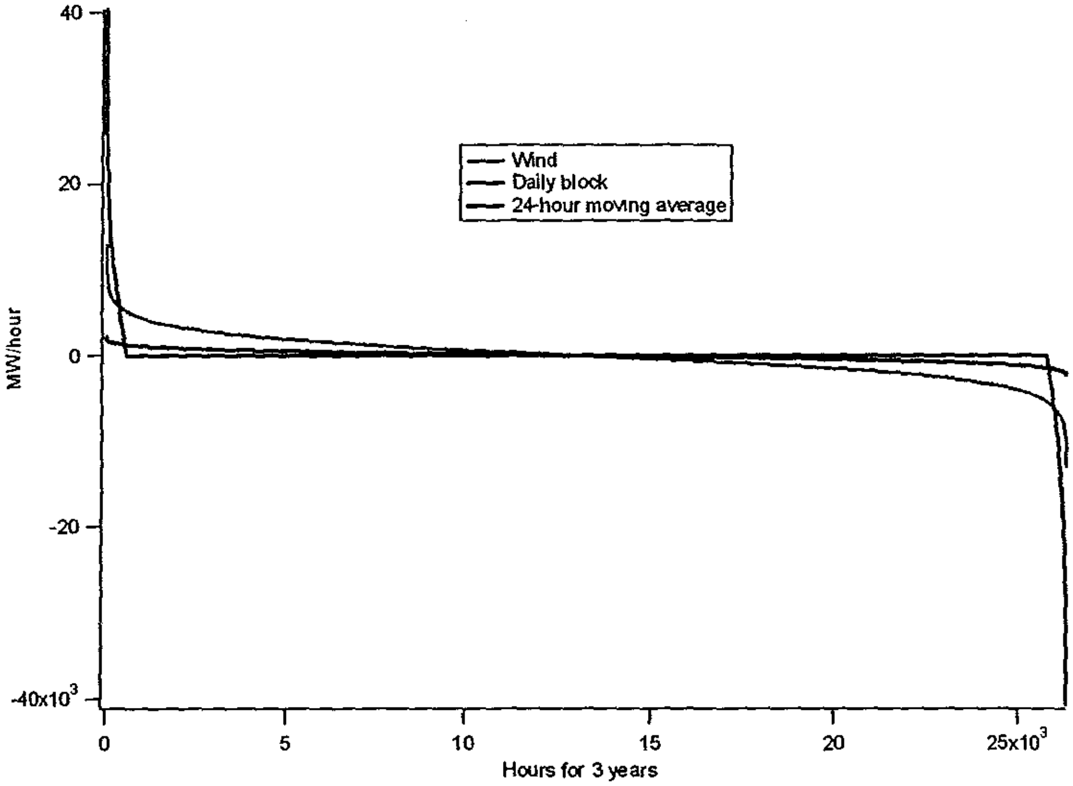

Figure 16. 3-year ramp duration curve shows many hours of relatively small ramps.

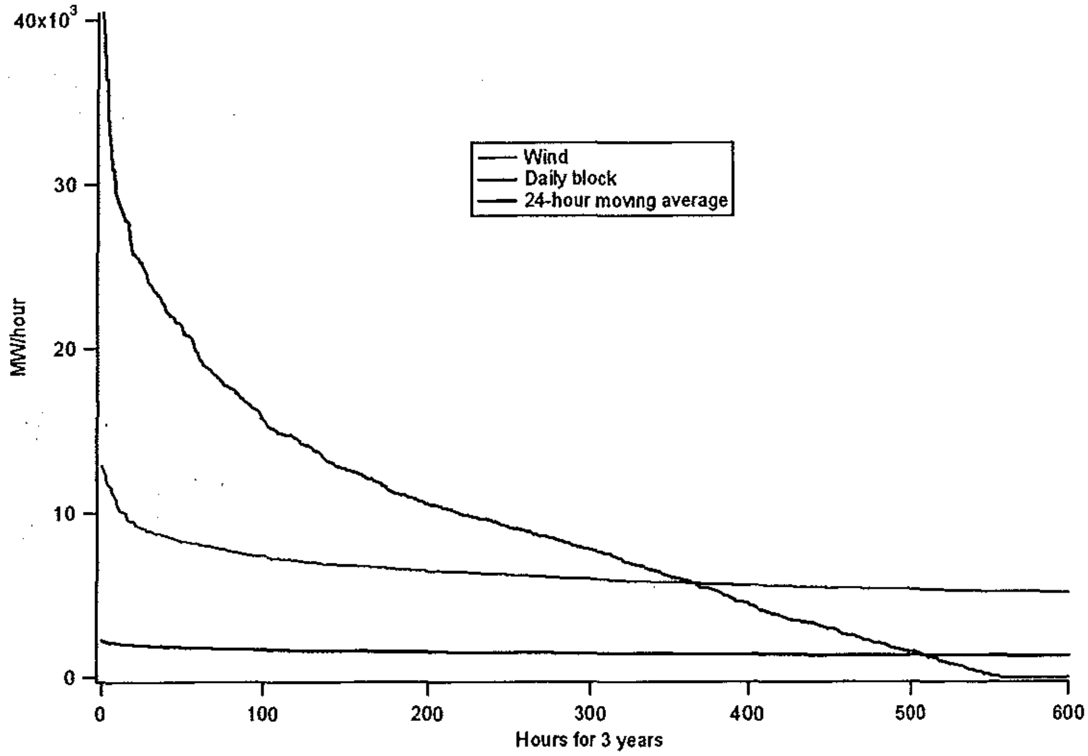

Figure 17. Extreme up-ramps occur in the daily flat block compared to wind, but the 24-hour moving average appears much more benign.

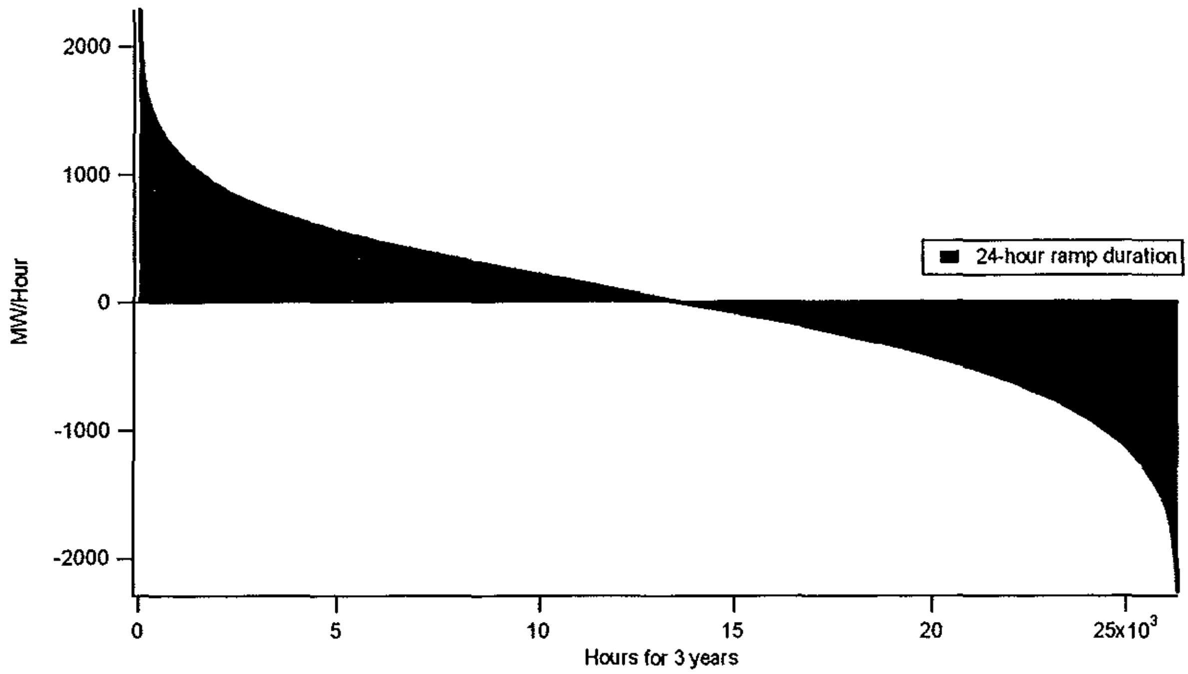

Figure 18. Duration curve for the 24-hour moving average proxy.

The 168-hour moving average has a significant smoothing effect on hourly ramps. It appears to be promising as a benchmark resource. The one-week moving average ramp duration curve appears in Figure 19 and shows that the ramps all fall within the range of -353 MW/hour to 381 MW/hour.

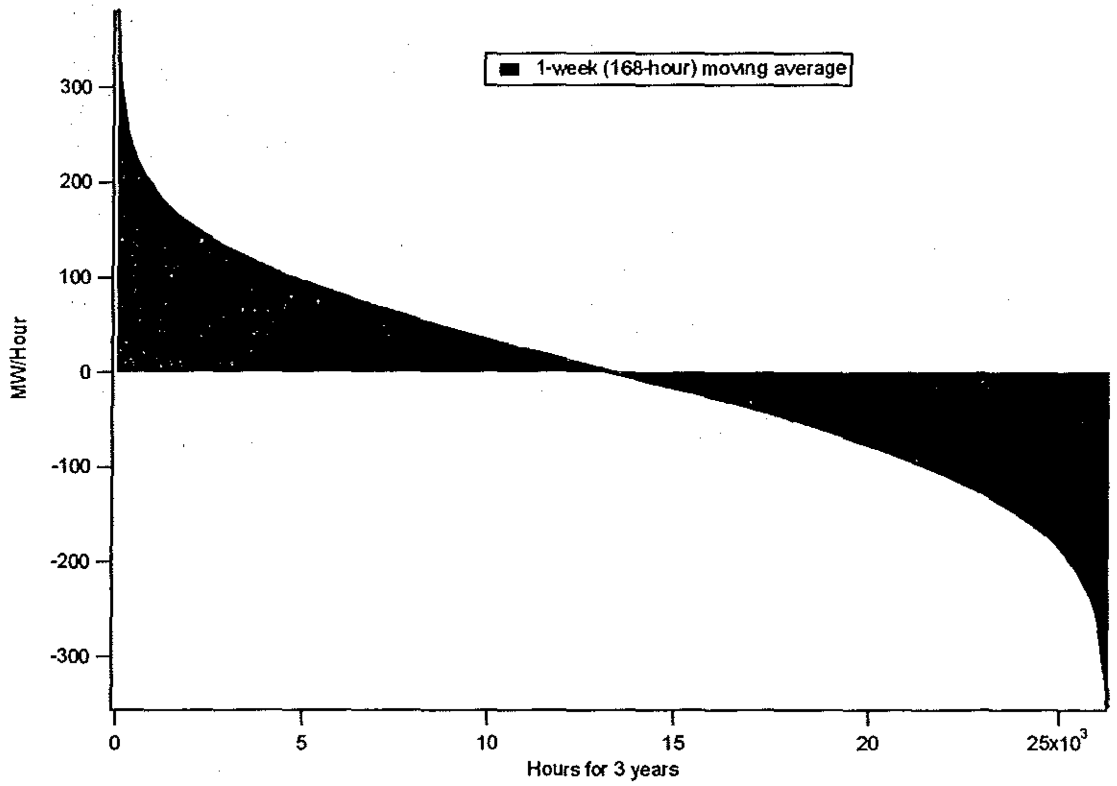

Figure 19. A 168-hour (1 week) moving average proxy has very little ramp from hour to hour.

However, there is still a lot of variability that exists in the 168-hour moving average, as indicated in Figure 20, and in a more detailed representation in Figure 21.

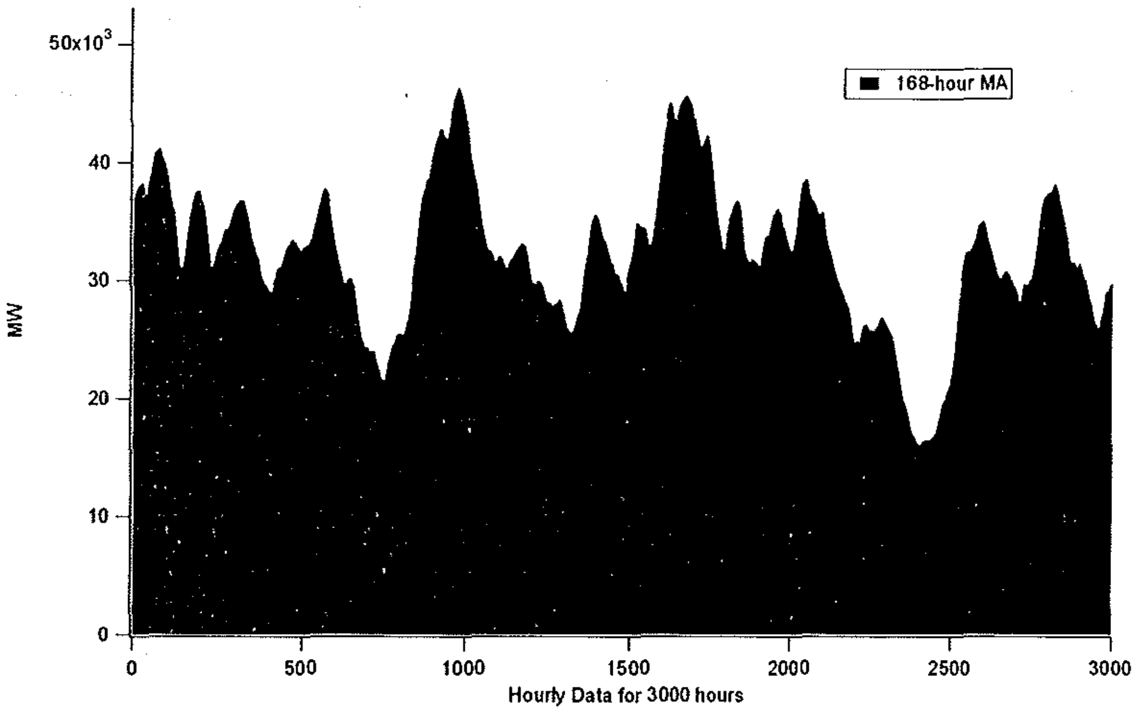

Figure 20. Zooming in on the first 3,000 hours shows the variability in the 168-hour moving average.

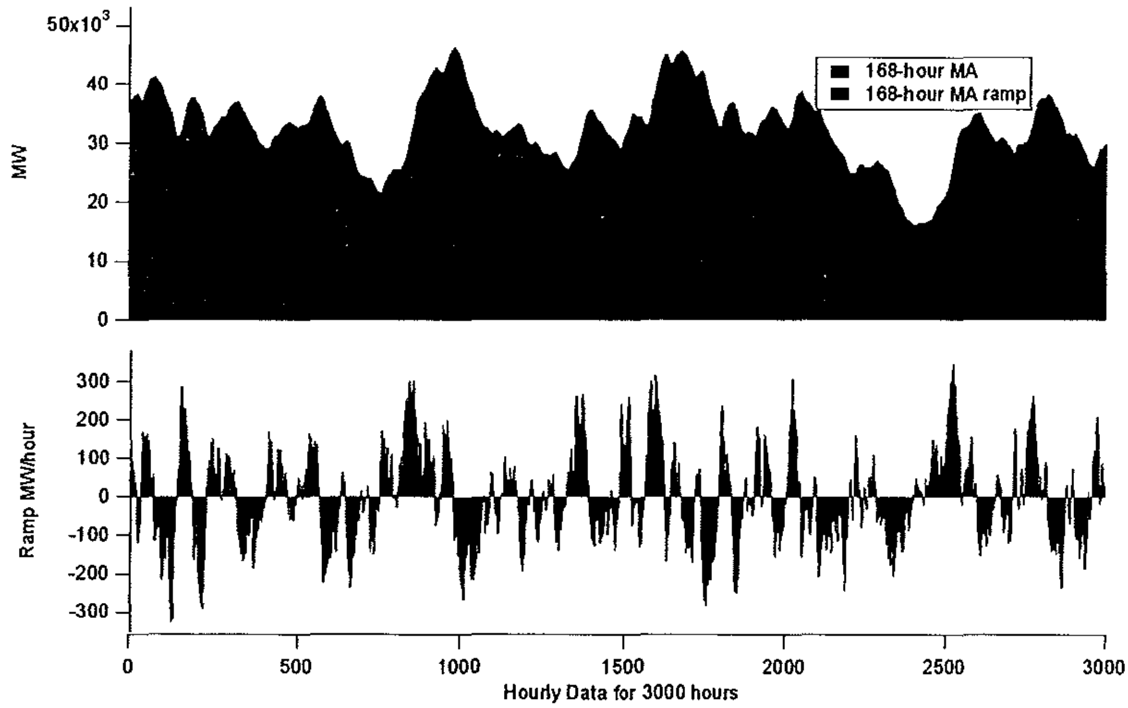

Figure 21. Zooming in on the first 3,000 hours of the 168-hour moving average shows the pattern of variability and ramp characteristics.

Discussion of Proxy Resource Issues

Using a fixed flat energy block as a proxy resource for wind integration cost analysis introduces significant inter-day ramps at high penetrations. These ramps are not real, nor do they provide a firm basis for a comparison/proxy resource at moderate to high wind penetrations. The impact of these artificial ramps is expected to vary depending on the size of the ramp and the position of generating units in the dispatch stack at the block boundaries (such as the 6-hour or 24-hour times of day). At lower penetrations, this impact may be more moderate, but could still be significant, mimicking the behavior of 1-hour block energy schedules that are still widely used in the Western Interconnection.

All of the proxy methods examined here have a significant market-value component that contributes to integration cost estimates. This intertwines the integration cost with an energy value differential that is not real—it is an artifact of the constructed proxy resource. This differential can in principle be removed from the analysis, using the appropriate LMPs from each of the modeling cases: the proxy resource case and the wind case.

Conclusions

As larger and larger amounts of wind generation are installed, we increasingly gain environmental and fuel savings benefits. Along with these benefits, there are costs that result from wind variability and uncertainty. Wind integration costs cannot be calculated directly. Instead, the power system is simulated with and without wind generation, and the difference in total system costs is attributed to wind integration. A proxy energy source that does not include variability or uncertainty must be included in the "without wind" case or else wind integration costs would be credited with the wind energy itself. Finding an appropriate proxy energy source is surprisingly difficult.

Selecting an appropriate non-varying and non-uncertain proxy energy source is difficult because any difference in the *value* of the proxy energy and the wind energy shows up in the calculated wind integration cost. A daily flat-block energy schedule that matches the daily wind energy output seems ideal because it is both certain and steady. Unfortunately, the daily flat block tends to have more on-peak energy and less off-peak energy than the wind itself. Consequently, the daily flat block is worth $1.50-$2.00/MWh more than the actual wind energy. Wind integration studies that utilize the flat daily block overstate wind integration costs.

Daily flat blocks also can have large step changes at midnight. These step changes result in artificial ramping requirements that the real power system never sees. Rolling averages of 24 to 168 hours can be used to eliminate the step changes. These rolling averages still have the problem that the proxy energy value is higher than the actual wind energy value.

While we hoped to develop an ideal proxy energy resource to use in wind integration studies, we found that the problem is over specified. The proxy must be unvarying, certain, and of the same value as the actual wind. Meeting the certainty and value requirements simultaneously is not strictly possible. It does not appear to be possible to relax the two requirements slightly and develop a solution that is adequate for engineering studies. The best solution may be to use a 24-hour rolling average to provide certainty and near invariability, while eliminating artificial ramps at midnight that are associated with the daily flat blocks. The difference in energy *value* must then be backed out of the calculated integration cost.

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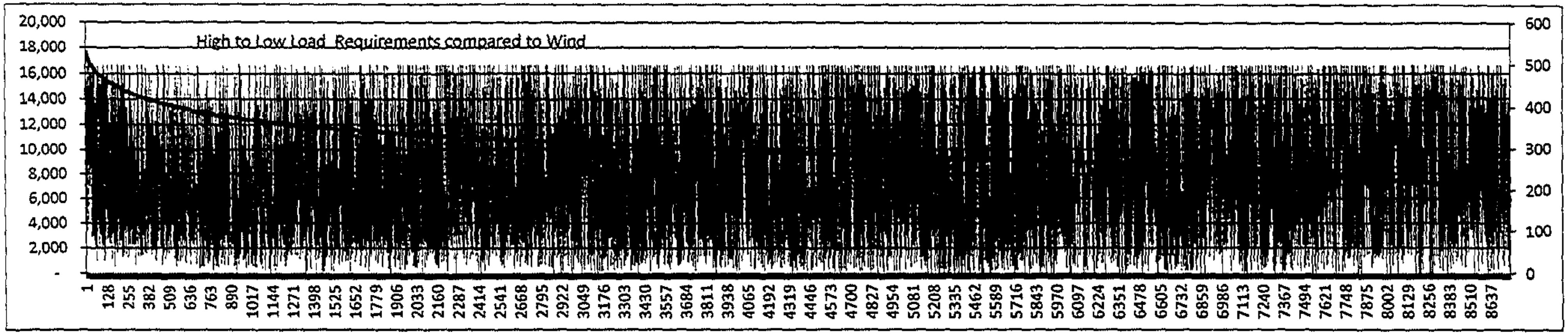
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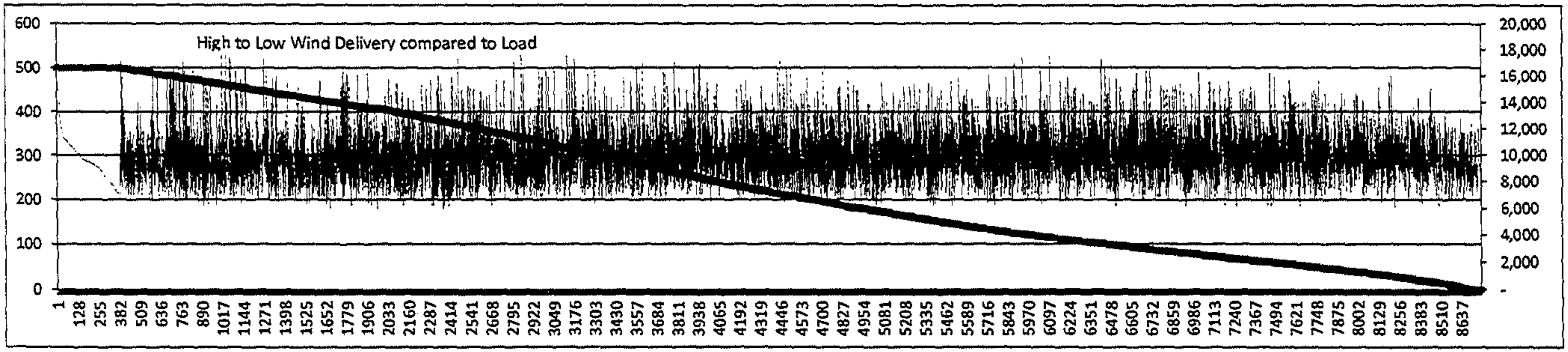
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2013 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS

Prepared by:

POTOMAC ECONOMICS

INDEPENDENT MARKET MONITOR FOR MISO

JUNE 2014

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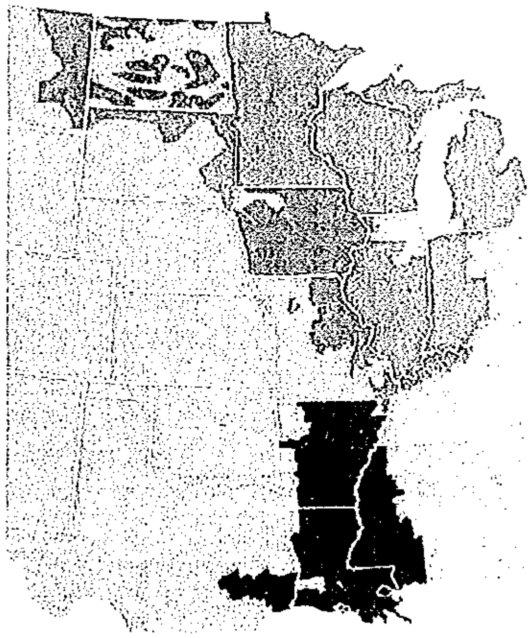
Guide to Acronyms

ARC	Aggregators of Retail Customers
ARR	Auction Revenue Rights
ASM	Ancillary Services Markets
BCA	Broad Constrained Area
BTMG	Behind-The-Meter Generation
CC	Combined Cycle
CDD	Cooling Degree Day
CMC	Constraint Management Charge
CONE	Cost of New Entry
CROW	Control Room Operating Window
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
DAMAP	Day-Ahead Margin Assurance Payment
DDC	Day-Ahead Deviation and Headroom Charge
DIR	Dispatchable Intermittent Resource
DR	Demand Response
DRR	Demand Response Resource
ECF	Excess Congestion Fund
EDR	Emergency Demand Response
EEA	Emergency Energy Alert
ELMP	Extended LMP
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFE	Firm Flow Entitlement
FTR	Financial Transmission Rights
GSF	Generation Shift Factors
GW	Gigawatt (1 GW = 1,000 MW)
GWh	Gigawatt-hour
HDD	Heating Degree Day
HHI	Herfindahl-Hirschman Index
IESO	Ontario Independent Electricity System Operator
IMM	Independent Market Monitor
ISO-NE	ISO New England, Inc.
JCM	Joint and Common Market
JOA	Joint Operating Agreement
kWh	Kilowatt-hour

LAC	Look-Ahead Commitment
LAD	Look-Ahead Dispatch
LMP	Locational Marginal Price
LSE	Load-Serving Entity
M2M	Market-to-Market
MATS	Mercury and Air Toxics Standards
MCP	Marginal Clearing Price
MISO	Midcontinent Independent Transmission System Operator
MMBtu	Million British thermal units, a measure of energy content
MTLF	Mid-Term Load Forecast
MVL	Marginal Value Limit
MW	Megawatt
MWh	Megawatt-hour
NCA	Narrow Constrained Area
NDL	Notification Deadline
NERC	North American Electric Reliability Corporation
NSI	Net Scheduled Interchange
NYISO	New York Independent System Operator
PJM	PJM Interconnection, Inc.
PVMWP	Price Volatility Make Whole Payment
PY	Planning Year
RAC	Resource Adequacy Construct
RCF	Reciprocal Coordinated Flowgate
RDI	Residual Demand Index
RGD	Regional Generation Dispatcher
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
SMP	System Marginal Price
SSR	System Support Resource
STLF	Short-Term Load Forecast
TLR	Transmission Line Loading Relief
VCA	Voluntary Capacity Auction
VLR	Voltage and Local Reliability
WUMS	Wisconsin-Upper Michigan System

Executive Summary

As the Independent Market Monitor (IMM) for Midcontinent Independent System Operator (MISO), we evaluate the competitive performance and efficiency of MISO's wholesale electricity markets. The scope of our work in this capacity includes monitoring for attempts to exercise market power, identifying market design flaws or inefficiencies, and recommending improvements to the market design and operating procedures. This Executive Summary to the *2013 State of the Market Report* provides an overview of our assessment of the performance of the markets and summarizes our recommendations.



MISO operates competitive wholesale electricity markets in the Midwest that encompasses a geographic area from Montana to Michigan. In late 2013, MISO integrated the MISO South Region covering portions of Texas, Louisiana, Mississippi, and Arkansas. This report also provides a brief summary of the initial market results in MISO South through April 2014.

MISO operates competitive markets for energy, ancillary services, capacity, and financial transmission rights (FTRs) to satisfy the electricity needs of its market participants. These markets coordinate the commitment and dispatch of generation to ensure that resources are meeting the system's demands reliably and at the lowest cost.

The MISO markets establish prices that reflect the marginal value of energy at each location on the network. These prices facilitate efficient actions by participants in the short term (e.g., to dispatch resources and schedule imports and exports) and efficient decisions in the long term (e.g., resource investment, retirement, and maintenance).

A. Competitive Performance of the Market

The MISO energy and ancillary service markets generally performed competitively in 2013. Conduct of suppliers was broadly consistent with expectations for a workably competitive market. We calculated a "price-cost mark-up" that compares energy prices based on actual offers to a simulated energy price based on our estimate of competitive offer prices. This analysis revealed a mark-up of just 1.7 percent, which indicates that the MISO markets were highly competitive. Additionally, our analysis did not reveal substantial evidence of potential attempts to exercise market power or engage in market manipulation. The output gap, a measure of potential economic withholding averaged approximately 0.1 percent of actual load, which is relatively low. Consequently, market power mitigation measures were applied infrequently.

The report does recommend two changes to the MISO market rules to address local market power concerns observed in 2013 and early 2014 where we concluded that the existing market power mitigation measures were not fully effective. The first change addresses market power associated with transitory conditions (usually associated with transmission or generation outages) that creates a severely-constrained area and enables a supplier in the area to raise prices sharply. Since these conditions do not persist long enough for MISO to define a narrow constrained area (NCA), and therefore be able to apply tighter market-power mitigation measures, substantial local market power can be exercised when these conditions persist.

The second recommended change addresses local market power associated with reliability commitments that can allow suppliers to extract excessive Revenue Sufficiency Guarantee (RSG) payments. Less than one-half of RSG payments in 2013 was associated with competitive offer prices. The other half was attributable to increases in one or more offer parameters above competitive levels, very little of which was subject to market power mitigation due to shortcomings to the existing mitigation framework. Based on our evaluation of the RSG results in 2013 and early 2014, we recommend a revision to the mitigation framework for RSG payments to make it comparable to the production-cost framework already employed by MISO to test and mitigate commitments for voltage and local reliability (VLR).

B. Market Outcomes and Prices in 2013

The all-in price of electricity, which is a measure of the total cost of serving load in MISO, averaged $32.51 per MWh. The energy component made up nearly the entire all-in price, and ranged from $31.81 in the West Region to $33.72 in the East Region. Prices were 12.2 percent higher than in 2012 because of higher natural gas prices and slightly higher load in 2013.

Natural gas prices rose 35 percent in 2013. The correlation between energy and natural gas prices is expected in a workably competitive market where natural gas-fired resources are often the marginal supply.

Although load rose by 0.9 percent, summer 2013 was not as hot as the summers in prior years. Nevertheless, peak conditions in mid-July tested the performance of the markets. We found again that shortcomings regarding interchange scheduling and coordination resulted in substantial economic and reliability costs in MISO and neighboring markets. We continue to recommend a coordinated transaction scheduling system that would address this concern. Ancillary services prices all rose considerably in 2013 and reflected the increased cost and opportunity cost of providing reserves. Although reduced from 2012, shortage pricing was most significant in the spring, when MISO's ability to handle the ramp demands of the system is more limited than in peak load months. Shortage pricing accounted for less than 10 percent of the average regulation and supplemental reserve clearing prices but nearly 25 percent of the spinning reserve clearing price. MISO's introduction of a "regulation mileage" payment did not materially impact regulation clearing prices in 2013.

C. Long-Term Economic Signals and Resource Adequacy

This report shows that MISO's economic signals in 2013 would not support private investment in new resources, which is partly due to the modest capacity surplus that currently exists in MISO. However, we believe the economic signals would continue to be inadequate even under little or no surplus because of the shortcomings of MISO's current capacity market described in this report. This resource adequacy concern is likely to rise as environmental regulations, increasing wind output, and low natural gas prices accelerate the retirements of many coal-fired resources in the next two years.

In the near-term, our assessment indicates that the system's resources should be adequate for summer 2014 if the peak conditions are not substantially hotter than normal. MISO estimates a planning reserve margin of 30 percent for the South Region and 19.8 percent for the Midwest Region, well in excess of the planning reserve requirement of 14.8 percent. Incorporating a realistic performance from MISO's demand response (DR) capability and hotter than normal summer conditions, however, reduces the margin in the Midwest Region to below 7 percent.

Given that this margin must account for forced outages that can average five to eight percent of the reserve margin and MISO's operating reserve requirements that are more than two percent of its peak load, MISO would need to rely on non-firm imports and emergency actions to satisfy its needs under these conditions.

While the supply is likely adequate for the upcoming summer, more stringent environmental regulations and other factors (e.g., sustained low natural gas prices and rising demand) will gradually decrease MISO's planning reserve margins. MISO's most recent surveys indicate expected coal retirements of 8 to 10 GW by April 2016, which would cause MISO to be capacity-deficient. Hence, it is important for resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base.

MISO made several improvements to its resource adequacy construct (RAC) in 2013, including replacing the monthly Voluntary Capacity Auction (VCA) with an annual Planning Resource Auction (PRA) that features zonal requirements for capacity. This zonal framework should provide a more accurate signal of the value of capacity in various locations. However, two significant shortcomings continue to undermine the efficiency of the RAC: (1) the representation of the demand for capacity in MISO's PRA; and (2) the prevailing barriers to capacity trading between PJM and MISO. These issues contributed to MISO's auction prices clearing near zero in all auctions in 2013.

The minimum capacity requirements and deficiency price set forth in Module E of the MISO Tariff establish a "vertical demand curve" for capacity, which implicitly values incremental capacity above the minimum requirement at zero. This is inconsistent with its true reliability value to the system and results in inefficient capacity market outcomes. Hence, we continue to recommend MISO work with its stakeholders to develop a sloped demand curve that would recognize that incremental capacity above the minimum requirement has value (i.e., improves reliability). This change would allow capacity prices to rise efficiently as capacity margins fall to accurately signal the value of capacity to both new investors and to suppliers considering environmental retrofits.

D. Transmission Congestion

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources, establishing efficient, location-specific prices that represent the marginal costs of serving load at each location.

The value of real-time congestion in 2013 rose 22 percent to $1.59 billion. This increase was due in part to higher fuel prices because higher fuel prices increase the costs of dispatch actions taken to manage network flows. Congestion rose fastest in the West Region due to significant outages. In addition, the full adoption of the dispatchable intermittent resource (DIR) type has substantially improved MISO's ability to alter the dispatch of wind resources to manage congestion and allowed this congestion to be fully priced.

The increase in real-time congestion cost was also reflected in the day-ahead market, where collected congestion costs rose 8.3 percent in 2013. The day-ahead congestion revenue collected by MISO is paid to holders of financial transmission rights (FTRs), which represent the economic property rights of the transmission system. Because the FTRs held by MISO's customers exceeded the capability of the transmission system in some periods—the system was limited because of unmodeled transmission outages—the day-ahead congestion revenue that MISO collected was 5 percent below the amount required to fully fund the FTR obligations. This shortfall declined in the second half of 2013 as MISO improved its modeling of the FTR market.

Finally, we identify in this report significant dispatch and pricing inefficiencies to managing external constraints that are activated when Transmission Line Load Relief (TLR) procedures are invoked. For example, in almost 80 percent of the intervals in which SPP called a TLR and MISO incurred substantial congestion costs to provide relief, the SPP constraint was not binding (i.e., the relief has no value). These constraints created excess costs for MISO's customers and we recommend changes to reduce these costs and improve efficiency.

E. Day-Ahead Market Performance

Convergence of energy prices between the day-ahead and real-time markets is important because day-ahead outcomes determine most resource commitments and are the basis for the payments to

FTRs. Energy prices converged well in most months, exhibiting a day-ahead premium of less than two percent at the Indiana Hub. This premium is eliminated after accounting for the real-time RSG cost allocations, which nearly doubled in 2013 to average $1.00 per MWh. There were persistent real-time premiums in the West Region, where the market was less effective at arbitraging locational differences due to congestion. In April, there were real-time premiums across MISO when operating reserve shortages were not anticipated day-ahead.

Virtual transactions were generally effective in improving the convergence of day-ahead and real-time energy prices. However, cleared transactions declined 12 percent, of which one-third were price-insensitive. Price-insensitive transactions are often placed to establish an energy-neutral position (offsetting virtual supply and demand) between locations to arbitrage congestion-related price differences between the day-ahead and real-time markets. We believe these balanced positions are valuable in improving the convergence of congestion patterns between the day-ahead and real-time market. Accordingly, we recommend MISO develop a virtual spread product that would allow participants to engage in this activity more efficiently.

F. Real-Time Market Performance and Uplift

Substantial volatility in real-time energy markets occurs because the demands of the system can change rapidly and because supply flexibility is restricted by resources' physical limitations. In contrast, the day-ahead market is less volatile because it operates over a longer time horizon with more commitment options, dispatch flexibility, and liquidity provided by virtual transactions.

MISO's real-time market produces new dispatch instructions and price signals every five minutes. Because settlements are based on hourly average prices, the MISO market includes Price Volatility Make-Whole Payments (PVMWP) to ensure that suppliers have the incentive to be flexible and are not harmed when they respond to MISO's five-minute dispatch instructions. PVMWP declined 10 percent from 2012 to $55.5 million, consistent with a comparable decline in price volatility. Our report shows that these payments would be substantially reduced and suppliers would have better incentives to follow MISO's dispatch instructions if it settled with participants on a five-minute basis. This would also improve incentives to schedule imports and exports more efficiently. Hence, we continue to recommend that MISO implement five-minute settlements for generators and external transactions.

RSG payments are made in both the day-ahead and real-time markets in order to ensure suppliers' offered costs are recovered when a unit is dispatched. Real-time RSG payments rose 54 percent from 2012 to $81 million, nearly half of which was due to the significant rise in fuel prices. Lower day-ahead purchases, particularly in the first half of the year, resulted in MISO making more resource commitments after the day-ahead market and increasing the capacity-related RSG payments. Day-ahead RSG payments increased by nearly 25 percent because of higher fuel prices and more VLR commitments, which are most often made day-ahead.

FERC recently approved changes we recommended to the allocation of RSG costs to make it substantially more consistent with their causes. These changes provide more efficient incentives to market participants. However, FERC rejected one of the recommended changes, finding that MISO did not provide sufficient evidentiary support. MISO will be refiling to make this change with additional support.

G. External Transaction Scheduling and External Congestion

As in prior years, MISO remained a substantial net importer of power in 2013, averaging 3.7 GW per hour in the real-time. Price differences between MISO and neighboring areas create incentives to schedule imports and exports that alter the net interchange between the areas. Efficient interchange is compromised by several shortcomings to the market design, including (1) flawed interface pricing on market-to-market and other external constraints, and (2) suboptimal and poorly-coordinated interchange scheduling.

Addressing the inadequate interchange coordination is important because it results in inefficient transactions that increase price volatility, reduce dispatch efficiency, and create operating reserve shortages. The most promising means to improve interchange coordination is to allow participants to submit offers to transact within the hour if the spread in the RTOs' real-time prices is greater than the offer price. MISO is working with PJM on such a proposal.

Interface pricing is currently impacted by a flaw we first identified in 2012. When external constraints—either PJM market-to-market or TLR constraints—are activated by MISO, they will be managed and priced in the real-time market like any other constraint, which means that the LMPs at every location will include the marginal effects of the constraint. These calculations are reasonable at every nodal location except at MISO's interfaces. Since the external areas are generally already reflecting the congestion in their import and export settlements, including this congestion cost in MISO's interface prices creates a redundant settlement of the congestion. MISO receives no credit from PJM or other external systems for incurring these costs and they generally increase uplift costs to MISO's load. In 2013, this pricing flaw resulted in net overpayments of $16.5 million by PJM and MISO for market-to-market constraints and overpayments by MISO of $2.2 million for other external constraints. We have been working with PJM and MISO on this issue and there is now a consensus on the problem but not yet on a solution. We continue to recommend that MISO's interface prices include only the costs associated with its own transmission constraints.

H. Demand Response

Demand response is an important contributor to MISO's resource adequacy and provides a number of other benefits to the market. MISO continues to seek to expand its DR capability, including efforts to allow for Batch Load DR and Price Responsive Demand. Currently, MISO has more than 10 GW of DR resources, which includes 3,400 MW of behind-the-meter generation. However, most of MISO's capability to reduce load is in the form of interruptible load developed under regulated utility programs (referred to as "load-modifying resources" or LMR). MISO does not directly control LMR and it cannot set energy prices when it is called. MISO has been working with its utilities to improve real-time information on the availability of the LMRs. We have recommended that MISO develop a means to allow LMRs to set energy prices, which will become increasingly important as generating resources retire and MISO relies more heavily on LMRs under emergency conditions. We also recommend that MISO modify its emergency procedures to utilize its DR capability more efficiently.

Finally, it is important that the capacity credits are not overstated for DR resources that MISO does not test. Accurately accounting for the true capability of LMRs would potentially increase PRA auction clearing prices significantly. We estimate that the most recent PRA would have cleared at $84 per MW-day (instead of $16.75) if the nearly 6,000 MW of LMRs received a 50 percent capacity credit.

I. Recommendations

Although the markets performed competitively in 2013, we recommend a number of improvements. Some of these recommendations were made in prior reports, which is not unexpected as many of them require both Tariff and software changes that can require years to implement. MISO addressed a number of prior recommendations in 2013 and early 2014, which are discussed in the final section of this report. The table of recommendations in this section shows our current recommendations, organized by the area of the market they address.

MISO has been developing a market vision, which includes guiding principles and focus areas associated with the principles. We have mapped each of our recommendations to MISO's focus areas, shown below, to allow market participants and policy-makers to understand to focus of each recommendation and how it pertains to MISO's overall market vision. This mapping is shown in the second column of the table of recommendations.

Market Vision Focus Areas	
1	Enhance Unit Commitment and Economic Dispatch Processes
2	Maximize Economic Utilization of Existing and Planned Transmission Infrastructure
3	Improve Efficiency of Prices under All Operating Conditions
4	Facilitate Efficient Transactions Across Seams with Neighboring Regions
5	Streamline Market Administrative Processes that Reduce Transaction Costs
6	Maximize Availability of Non-Confidential and Non-Competitive Market Information
7	Support Efficient Development of Resources Consistent with Long-term Reliability and/or Public Policy Objectives

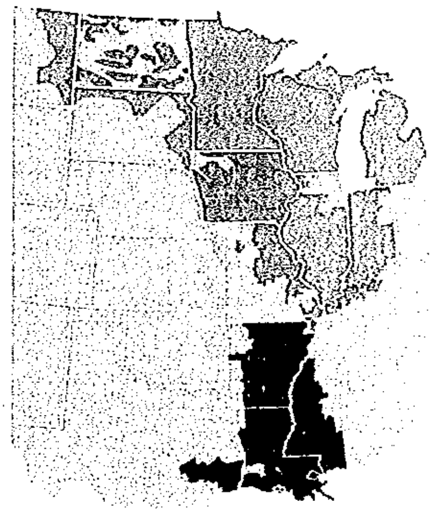
The table of recommendations also includes a "SOM number," which indicates the year in which it was first introduced and the recommendation number in that year, and separately indicates whether the recommendation is of high benefit to the market and if it can be achieved in the short-term. Of the 22 recommendations shown below, four are new in 2013.

SOM Number	Focus Area(s)	Recommendation	High Benefit	Feasible in ST
Energy Pricing and Transmission Congestion				
2008-2	3, 7	Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set real-time energy prices.		✓
2012-2	3, 4	Implement a five-minute real-time settlement for generation and external schedules.	✓	?
2012-5	1, 2	Introduce a virtual spread product.	?	
2012-9	1, 3	Allow the definition of a "dynamic NCA" utilized when network conditions exist that create substantial market power.		✓
External Transaction Scheduling and External Congestion				
2012-3	4	Remove external congestion from interface prices to eliminate excess payments and charges to physical transactions	✓	✓
2005-2	1, 4	Expand the JOA to optimize the interchange with PJM to improve price convergence with PJM.	✓✓	
2012-4a	2	Improve external congestion processes by modifying how relief obligations are calculated by basing them on Net Market Flows, not gross forward flows		
2012-4b	4	Improve the pricing of external congestion associated with external constraints by setting the MVL on external (non-M2M) flowgates at a reasonable level.		✓
Guarantee Payment Eligibility Rules and Cost Allocation				
2013-1	1	Allocate real-time RSG only to harming deviations (pre- and post-NDL).		✓
2013-2	1	Improve allocation of VLR costs by identifying VLR commitments made by the DA market.		✓
2010-11	1	Improve the efficiency of reserve scheduling by eliminating guarantee payments to deployed spinning reserves.		✓
2013-3	1	Improve the market power mitigation measure applicable to RSG.	✓	✓

SOM Number	Focus Area(s)	Recommendation	High Benefit	Feasible in ST
Improve Dispatch Efficiency and Real-Time Market Operations				
2011-7	1, 3	Implement a ramp capability product to address unanticipated ramp demands.	✓	
2012-12a	1	Develop enhanced tools to identify units that are derated or not following dispatch so that they may be placed off-control.		✓
2012-12b	1	Tighten thresholds for uninstructed deviations.	✓	✓
2011-10	1, 2	Implement procedures under the JOA that would improve day-ahead M2M coordination with PJM.		
2012-16	1, 3	Re-order MISO's emergency procedures to utilize demand response efficiently.		✓
2012-17	1, 3	Recognize supplemental reserves being provided from quick-start units when they are starting.		?
Resource Adequacy				
2008-11	7	Remove inefficient barriers to capacity trading with adjacent areas.		
2010-14	7	Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.	✓✓	
2011-14	7	Evaluate capacity credits provided to LMRs to increase their accuracy.		✓
2013-4	7	Improve alignment of the PRA and the Attachment Y process governing retirement and suspensions		✓

I. Introduction

As the Independent Market Monitor (IMM) for MISO, Potomac Economics is responsible for evaluating the competitive performance, design, and operation of wholesale electricity markets operated by MISO. In this *2013 State of the Market Report*, we provide our annual evaluation of MISO's markets and our recommendations for future improvements.



MISO introduced competitive wholesale electricity markets on April 1, 2005. These markets include day-ahead and real-time energy markets and a market for Financial Transmission Rights (FTRs). The energy markets are designed to facilitate an efficient daily commitment of generation, to dispatch the lowest-cost resources to satisfy the system's demands without overloading the transmission network, and to provide transparent economic signals to guide short-run and long-run decisions by participants and regulators. The FTR market allows participants to hedge the risks of congestion associated with serving load or engaging in other transactions.[1]

In 2009, MISO began operating as a balancing authority and introduced markets for regulation and contingency reserves, known collectively as Ancillary Services Markets ("AS markets" or "ASM"), and a monthly spot market for capacity. AS markets jointly optimize the allocation of resources between energy and ancillary services products. This joint optimization also allows energy and ancillary services prices to reflect the opportunity cost tradeoffs between products, as well as shortages of both products. The capacity market was modified in 2013 as MISO replaced the Voluntary Capacity Auction (VCA) with an annual Planning Reserve Auction (PRA). The PRA allows participants to buy and sell capacity to satisfy residual capacity requirements and better identifies locational capacity needs throughout MISO. Though an improvement, the PRA continues to reflect a poor representation of the demand for capacity (or planning reserves), which undermines its ability to provide efficient economic signals.

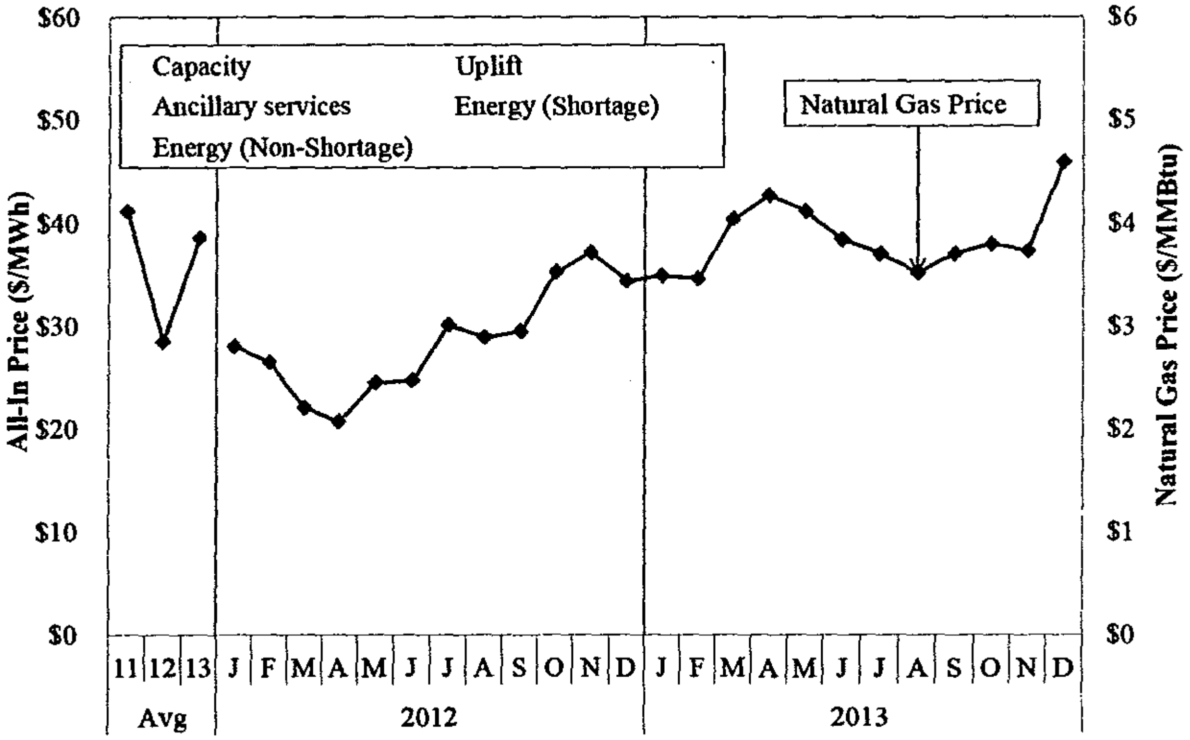
1 FTRs are financial instruments that entitle their holder to a payment equal to the congestion price difference between locations in the day-ahead energy market.

II. Prices and Load Trends

A. Market Prices in 2013

Figure 1 summarizes changes in energy prices and other market costs by showing the all-in price of electricity, which is a measure of the total cost of serving load in MISO. The all-in price of electricity is equal to the load-weighted average real-time energy price plus capacity, ancillary services, and real-time uplift costs per MWh of real-time load.[2]

Figure 1: All-In Price of Electricity
2012–2013



The all-in price in 2013 averaged $32.51 per MWh, an increase of 12.2 percent from 2012. This increase was primarily a result of significant increases in fuel prices, including a 35 percent rise in natural gas prices. Although load rose slightly, MISO did not experience as hot a summer as it did in 2012. As a result, MISO experienced fewer shortages and the share of the energy component associated with shortage intervals declined by more than one-half to 1.6 percent.

2 Capacity costs are estimated by multiplying the VCA clearing price times the capacity requirements in each month. Beginning in June 2013, these costs reflect the PRA clearing price of $1.05 per MW-day.

As in prior years, the energy component constituted nearly the entire all-in price. Uplift costs, including Revenue Sufficiency Guarantee (RSG) payments and Price Volatility Make-Whole Payments (PVMWPs), rose four cents to $0.27 per MWh. Ancillary services costs added $0.17 per MWh, a 4-cent increase from 2012 despite fewer shortages. This increase reflects the higher opportunity costs of foregone energy, which tend to increase with fuel prices.

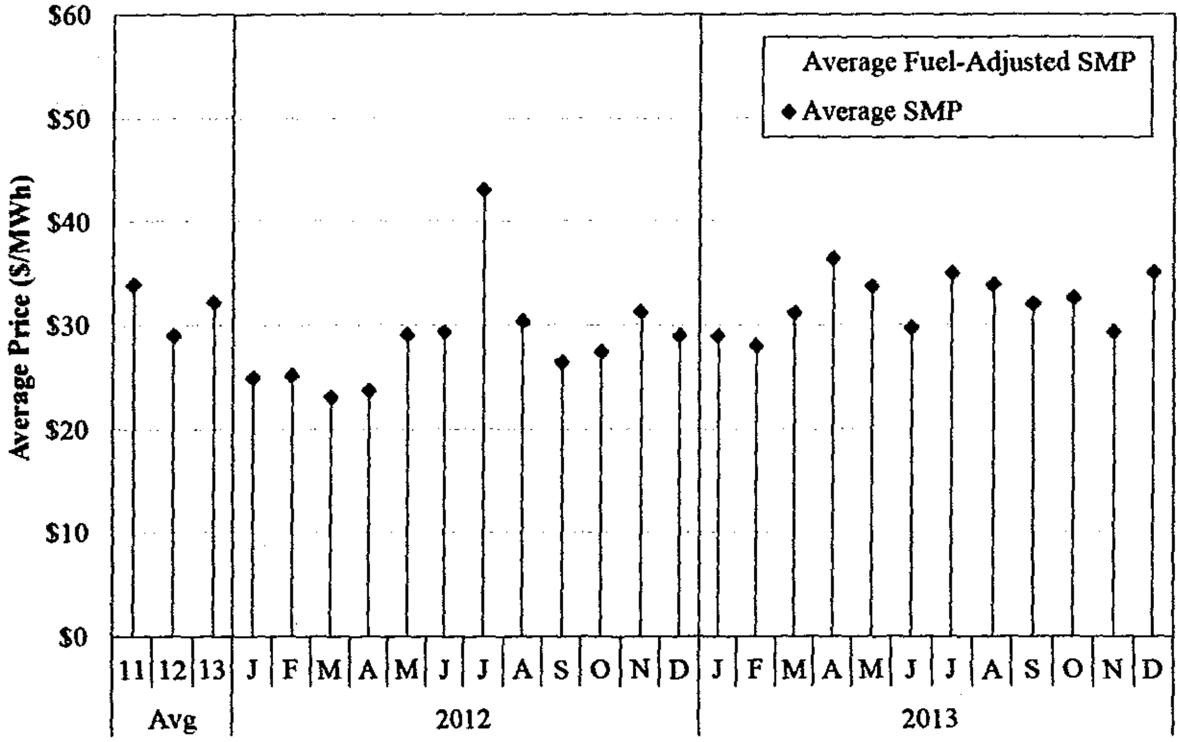
Finally, capacity costs contributed only four cents per MWh to the all-in price. All capacity auctions in 2013—five monthly VCA auctions in January to May, an annual PRA in June and a transitional PRA in November to facilitate the integration of the MISO South region—cleared at very low prices because of the prevailing surplus and the market design issues discussed in this report. It will be critical to address these issues in the near future because increased retirements and capacity exports are projected to generate a capacity deficiency as soon as 2016. Improving the performance of the capacity market may play a pivotal role in ensuring that MISO will continue to have access to sufficient capacity.

The figure also shows that energy price fluctuations are strongly correlated with natural gas price movements. This correlation exists because fuel costs represent the majority of most suppliers' marginal production costs. Since suppliers in a competitive market have an incentive to offer supply at marginal cost, changes in fuel prices translate to changes in offer prices. Natural gas prices in 2013 rose 35 percent from 2012 to average $3.85 per MMBtu.

To estimate price effects of factors other than the change in fuel prices, we calculate a fuel price-adjusted System Marginal Price (SMP) that is based on the marginal fuel in each five-minute interval. To calculate this metric, each real-time interval's SMP is indexed to the three-year average of the price of the marginal fuel during the interval.[3] Although the average SMP in 2013 rose 3.5 percent from 2012, the figure shows that average fuel-adjusted energy prices declined 2.3 percent. This indicates that non-fuel factors, most notably a milder summer and fewer instances of shortage pricing, contributed to the decrease in the fuel-adjusted SMP.

3 See Figure A4 in the Appendix for a detailed explanation of this metric.

Figure 2: Fuel-Adjusted System Marginal Price
2012–2013



B. Fuel Prices and Energy Production

The increase in gas prices in 2013 brought them back from the unusually low price levels that prevailed in 2012, which resulted in natural gas-fired units producing 28 percent less energy in 2013 than they did in 2012. Although natural gas-fired units were a marginal unit in less than one-third of all intervals in 2013, natural gas prices remain an important driver of energy prices because these intervals tend to be the highest-load periods.

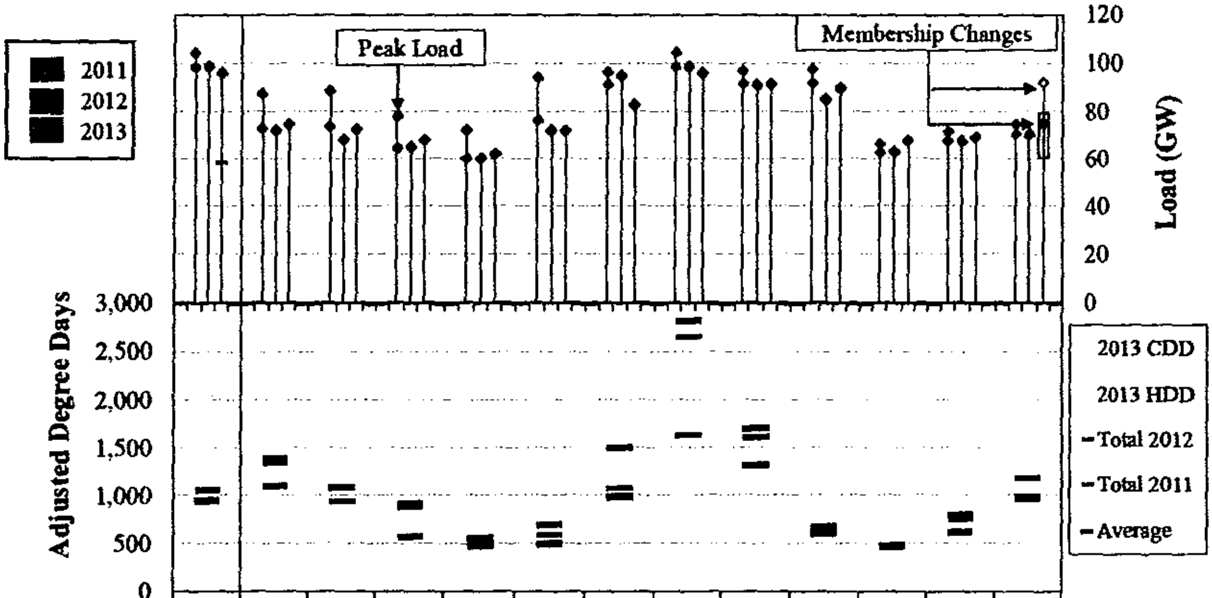
In 2013, coal-fired resources still provided over two-thirds of total generation in MISO and set price in some locations in 93 percent of intervals, including almost all off-peak intervals. Congestion frequently caused both natural gas and coal-fired resources to be on the margin in the same interval in different areas of the footprint. Western (e.g., Powder River Basin) coal prices rose 18 percent, while Eastern coal prices declined five percent.

Wind capacity and output continue to grow in MISO, increasing by 5 and 11 percent in 2013, respectively. Wind generated 7.4 percent of all energy in MISO in 2013, compared to 3.5 percent just three years ago. MISO has continued to evolve its market rules, software, and operating procedures to accommodate the rapidly expanding wind capacity. The expansion of dispatchable wind resources under the Dispatchable Intermittent Resource (DIR) capability has resulted in wind resources setting price in over one-half of all intervals (at an average price of -$11 per MWh). Wind resources typically set price in confined areas where its output is contributing to localized congestion, and it rarely sets prices system wide.

C. Load and Weather Patterns

Figure 3 illustrates the influence of weather on load by showing the heating and cooling requirements together with the monthly average load levels for 2011 to 2013. The top panel shows the monthly average load in the bars and the peak monthly load in the diamonds. The bottom panel shows monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) summed across four representative locations in MISO.[4]

Figure 3: Heating and Cooling Degree Days
2011-2013



% Chg 12-13	2013	J	F	M	A	M	J	J	A	S	O	N	D
Avg. Load	0%	2%	4%	7%	4%	-4%	-7%	-12%	0%	4%	2%	3%	7%
Degree Days	-2%	10%	16%	76%	28%	-5%	-29%	-37%	-3%	12%	8%	10%	30%

4 HDDs and CDDs are defined using aggregate daily temperature observations relative to a base temperature (in this case, 65 degrees Fahrenheit). To account for the relative impact of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize their effects on load as estimated by regression analysis. The long-term average degree-days are based on data from 1971 to 2000.

Total degree days declined by 2 percent in 2013 compared to 2012, primarily because of the milder summer weather in 2013.[5] Despite this decline, average load increased by 1 percent in 2013 as economic activity continued to grow at a modest pace in the Midwest. MISO set its annual peak load of 95,777 MW on July 18, which was slightly higher than its "50/50" forecasted peak of 93.8 GW from its *2013 Summer Resource Assessment*, but almost 4 GW below the more extreme "90/10" peak.

D. Evaluation of Peak Summer Days in 2013

MISO's highest loads in 2013 occurred in mid-July. Although conditions were not as tight as they were during the more severe heat waves in 2011 or 2012, MISO experienced a sustained period of above-average temperatures that produced peak loads in excess of the 50/50 forecast in the *Summer Assessment*. On each of the five days shown in Table 1 below, MISO declared Hot Weather Alerts and Conservative Operations. On July 17, MISO declared a Maximum Generation Alert (shown in yellow).

Table 1: Temperatures in MISO during the Peak Summer Week

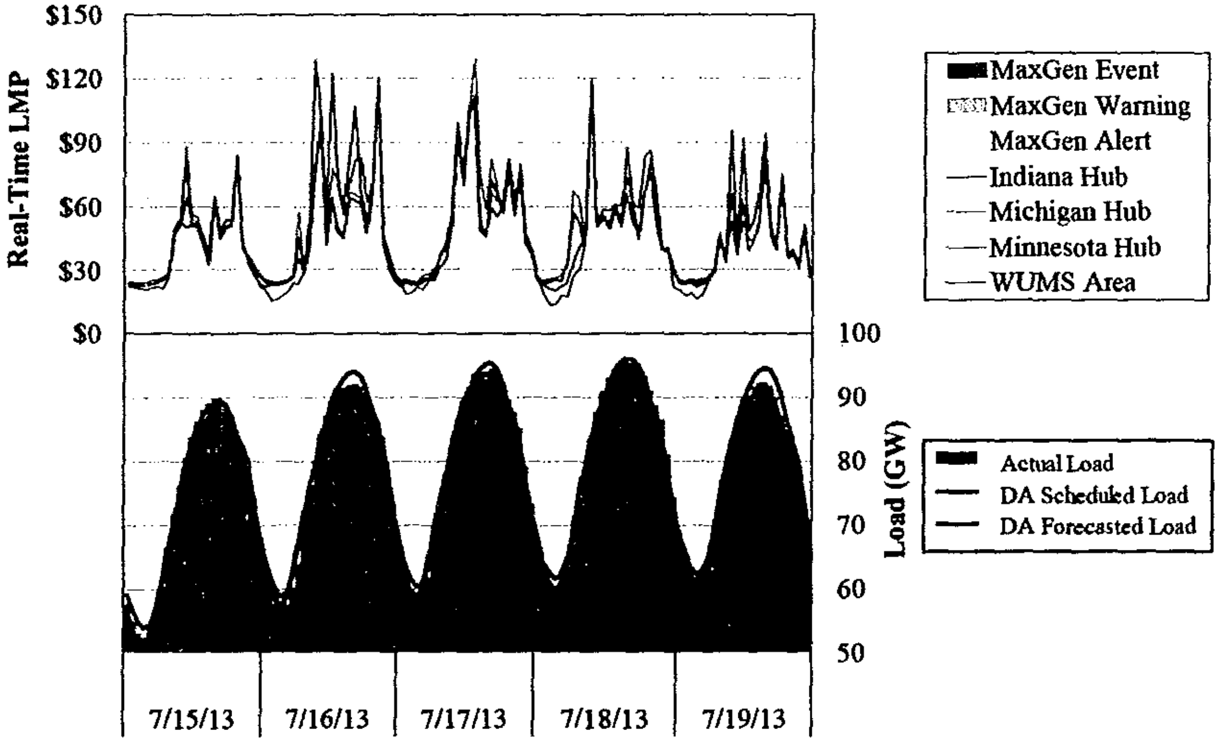
	Historical Average	July 15	July 16	July 17	July 18	July 19
Cincinnati	86	92	93	93	93	89
Detroit	84	93	90	94	94	95
Indianapolis	85	88	93	93	93	92
Milwaukee	80	85	93	95	95	94
St. Louis	89	91	93	94	94	98
Minneapolis	80	87	91	91	93	84

Figure 4 shows the day-ahead and real-time load in the lower panel and real-time prices in the upper panel. Actual loads on most days closely matched what was scheduled day-ahead, although under-scheduling on July 15 required substantial real-time capacity commitments. Load peaked on July 18, but supply conditions were tighter on July 17 (due to 4 GW less wind output). On this day, voluntary load curtailments after the Maximum Generation Alert declaration truncated the peak load, and resulted in a substantial reduction in energy prices.

5 Unless otherwise stated, changes in load in this report are adjusted for membership additions and departures.

Although MISO did not call for any demand response on this day, these results indicate the importance of allowing demand response to set energy prices when it is needed. Prices were reasonably volatile during these periods, but MISO did not exhibit significant reserve shortages.

Figure 4: Load and Real-Time Prices
July 15-19, 2013

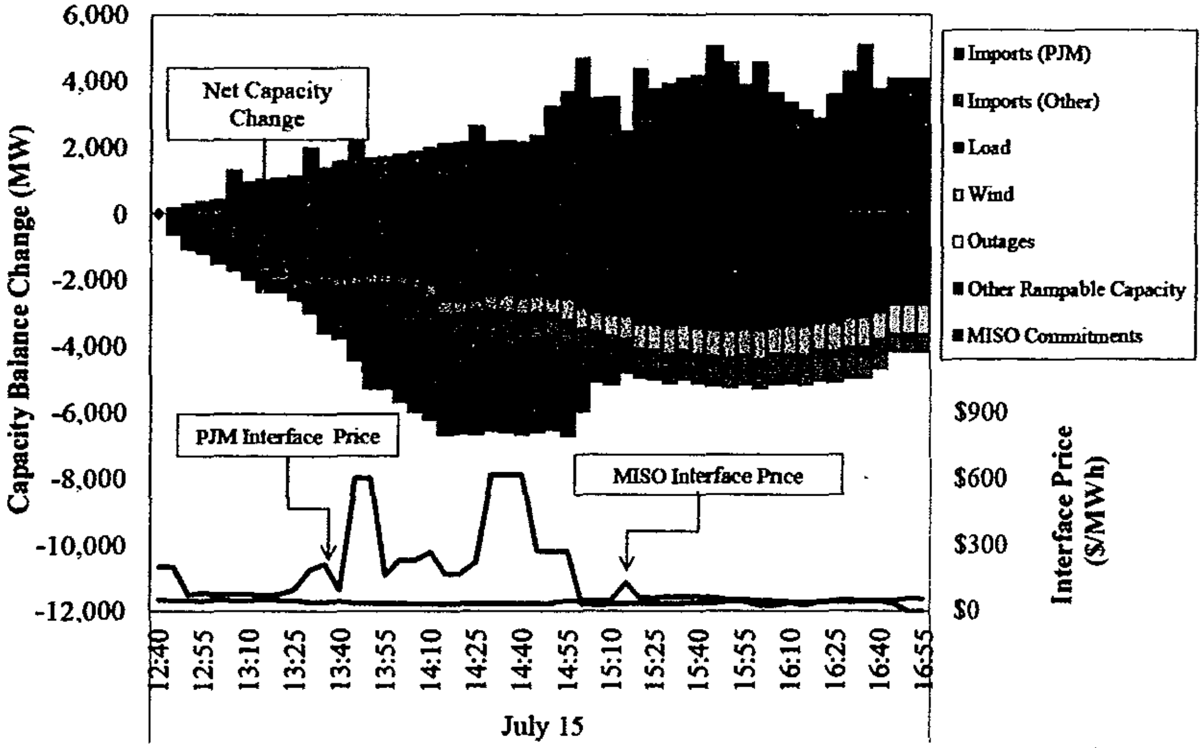


In addition to extremely high demand for electricity, other factors leading to price volatility on MISO's system and adjacent systems include changes in net scheduled interchange, generator and transmission outages and derates, fluctuations in wind generation and the timing of operator actions. To illustrate how these factors together contribute to volatility in the MISO market and adjacent markets, Figure 5 shows the cumulative impact of real-time supply and demand factors that directly impacted capacity levels in MISO and energy prices beginning at noon on July 15.

In this figure, "harmful" factors that contribute to higher prices are shown as positive values (reductions in supply or increases in demand), while "helpful" ones that reduce prices are shown as negative values. The "MISO Commitments" is capacity committed during the period. The "Other Rampable Capacity" is additional capacity that can be dispatched within five minutes that is made available on online units as they are ramping up. Net harmful capacity changes are shown in the red markers. All values are measured against their respective levels as of noon.

On this day, changes in NSI led to reserve shortages and high prices in PJM. This is the opposite of the events that occurred on several days in 2012, when large swings in NSI toward PJM precipitated shortages and high prices in MISO. The additional 2,200 MW of net imports from PJM after noon suppressed MISO prices to below $40 per MWh. In retrospect, the 1,600 MW of real-time capacity commitments by MISO were not needed to meet MISO's capacity needs. As a result, MISO's RSG payments to 64 separate units exceeded $150,000 per hour for much of the afternoon and totaled over $1.1 million for the day.

Figure 5: Contributing Factors to Capacity Levels and Energy Prices
July 15, 2013



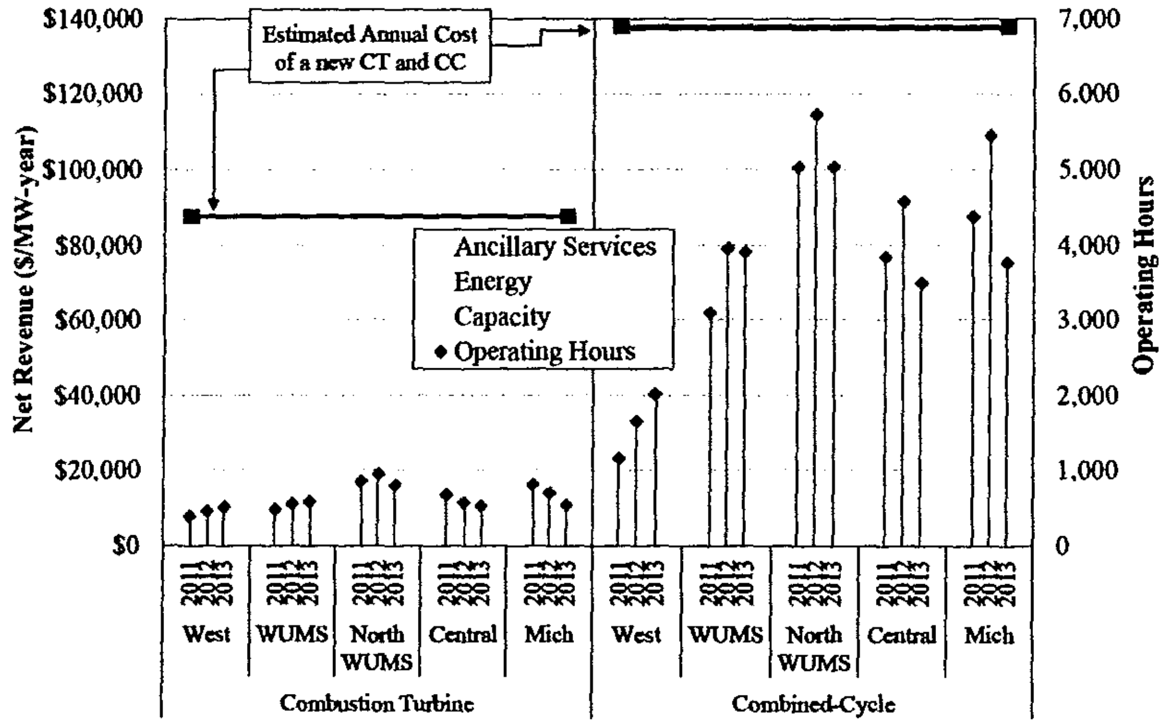
Current scheduling rules for interchange can lead to substantial market dysfunction under tight conditions, producing both substantial economic and reliability costs in MISO and neighboring markets. Later in the report, we show that nearly one-half of transactions from PJM in 2013 were scheduled in the unprofitable direction, and that many hours exhibited large price differences attributable to scheduling inefficiencies. Hence, we continue to recommend the RTOs make interchange optimization initiative a high priority. PJM supports this recommendation, but prefers to move toward implementation only after it has implemented similar processes with NYISO.

E. Long-Term Economic Signals

While price signals play an essential role in facilitating efficient commitment and dispatch of resources in the short term, they also provide long-term economic signals that govern investment (or retirement) of resources and transmission capability. This section reviews the long-term economic signals provided by the MISO markets. These economic signals can be evaluated by measuring the "net revenue" that a new generating unit would have earned from the market under prevailing prices.

More precisely, net revenue is the revenue that a new generator would earn above its variable production costs if it ran when it was economic and did not run when it was uneconomic. A well-designed market should produce net revenue sufficient to finance new investment when available resources are insufficient to meet system needs. Figure 6 shows estimated net revenues for a hypothetical new Combustion Turbine (CT) and Combined-Cycle (CC) generator for the prior three years in five different MISO regions. For comparison, the figure also shows the minimum annual net revenue that would be needed for these investments to be profitable (i.e., the "Cost of New Entry", or CONE).

Figure 6: Net Revenue Analysis
2011–2013



Estimated net revenues in 2013 for both types of units declined slightly from 2012 in most regions, and they continue to be substantially less than CONE in all regions. This is consistent with expectations because of the capacity market design issues we describe in this report and the prevailing near-term capacity surplus.

Despite recent improvements made to the Resource Adequacy Construct, there remain capacity market design issues that will continue to undermine MISO's economic signals as this surplus dissipates. This may occur as soon as the 2015–2016 planning year, when increased retirements and capacity exports are projected to generate a capacity deficiency. The retirements are largely due to forthcoming environmental regulations that are surveyed to affect 57 GW of the 75 GW of coal-fired capacity in MISO. To address this issue, we recommend a number of improvements to both the energy market and the capacity market. The next section discusses the supply in MISO and evaluates the design and performance of the capacity market as it relates to ensuring the adequacy of MISO's resources.

III. Resource Adequacy

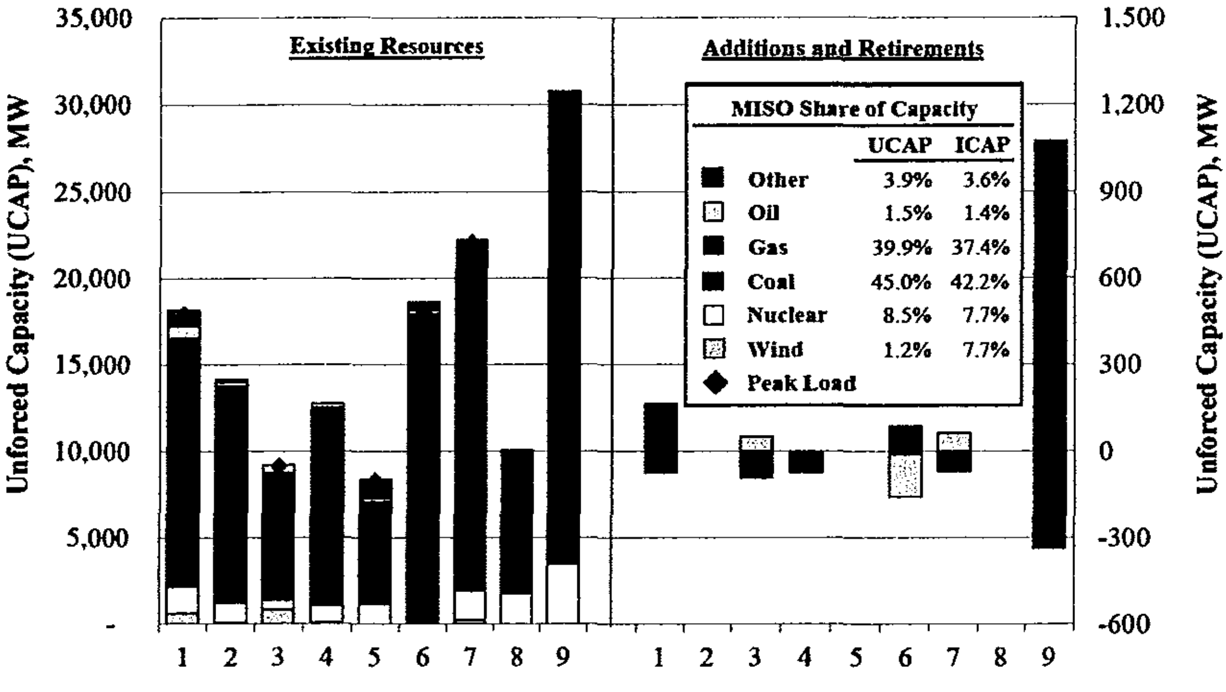
This section evaluates the supply in MISO, including:

- Summarizing the current resources and recent changes;
- Evaluating the adequacy of resources for meeting peak needs in 2014;
- Discussing future issues that may adversely affect supply; and
- Reviewing the outcomes and design of resource adequacy provisions.

A. Regional Generating Capacity

Figure 7 shows the summer 2014 capacity distribution of existing generating resources by Local Resource Zone. The left panel shows the distribution of Unforced Capacity (UCAP) by zone and fuel type, along with the forecasted 2014 peak load in each zone. The right panel displays the change in the generating capacity from last summer. The inset table breaks down total UCAP and ICAP quantities by fuel type. UCAP values are lower than Installed Capacity (ICAP) values because they account for forced outages and intermittency. Hence, wind capacity, although it makes up nearly 8 percent of nameplate capacity, does not feature prominently in this figure.

Figure 7: Distribution of Generating Capacity
By Fuel Type and Zone, Summer 2014



Unforced capacity exceeds the 2014 forecasted peak load in all zones, although the margin was less than 3 percent in five of the nine zones. Because the average output from wind units in the West region is often greater than their UCAP credit, the western areas frequently produce substantial surplus energy that is dispatched to serve load in eastern areas. This pattern produces the west-to-east flows and congestion patterns typically observed in the MISO markets.

Despite increased wind generating capacity and low natural gas prices, MISO continues to depend heavily on coal-fired generation, which accounts for nearly one-half of MISO's generating capacity. MISO is less reliant on coal resources than in prior years because the additional capacity in the newly-integrated South Region (zones 8 and 9) is predominantly natural gas-fired. As discussed later in this section, MISO expects large quantities of capacity to retire in response to environmental rules, and is forecasting a capacity shortfall as soon as 2016. MISO expects approximately 2 GW of coal retirements by this summer (nearly all of which have already occurred), although several hundred MW are expected to be suspended and not expected to return to service prior to retirement.

The most significant capacity additions are several natural gas-fired units in zone 9 that total over 1 GW. Several other capacity additions expected by summer 2014 are wind units, the majority of which are in western areas or in the "thumb" of Michigan, where wind profiles are attractive. Although wind resources are relatively costly, they benefit from a variety of subsidies, including production tax credits, state renewable portfolio standards, and the benefits of the transmission investments planned to improve their deliverability (i.e., Multi-Value Projects). These subsidies should cause the wind capacity levels to continue to rise over the next few years.

B. Planning Reserve Margins

This subsection assesses capacity levels in MISO and their adequacy for satisfying the forecasted peak loads for summer 2014. In its *2014 Summer Resource Assessment*, MISO presented baseline planning reserve margins alongside a number of valuable scenarios that show the sensitivity of the margins to changes in key assumptions. For example, MISO's *Assessment* includes a scenario that assumes hotter-than-normal peak conditions. This section includes our evaluation of MISO's planning reserve margins using the same capacity data as MISO used in its Summer Assessment so our data is consistent with MISO.

Over the past several years, we have commented on some of MISO's assumptions and worked with MISO to reconcile differences in these assumptions. In a limited number of areas, we continue to have concerns regarding factors that could cause MISO to be short of capacity. Therefore, we include some assumptions that differ from MISO's that lead to different estimated planning reserve margins. Table 2 shows four cases that show variations in key assumptions and illustrate the effects of these changes on MISO's planning reserve margin.

Table 2: Capacity, Load, and Planning Reserve Margins
Summer 2014

	MISO	IMM		
	Base Case	Realistic DR	High Temp Full DR	High Temp Realistic DR
Midwest Region				
Load	96,244	96,244	101,276	101,276
High Load Increase	-	-	*5,032*	*5,032*
Capacity	107,452	107,452	102,552	102,552
BTM Generation	*3,843*	*3,843*	*3,843*	*3,843*
*Hi Temp Derates**	-	-	*(4,900)*	*(4,900)*
Demand Response	4,636	2,318	4,636	2,318
Net Firm Imports	2,258	2,258	2,258	2,258
Transfer Limit	1,000	1,000	1,000	1,000
Margin (MW)	19,101	16,784	9,169	6,852
Margin (%)	19.8%	17.4%	9.1%	6.8%
South Region				
Load	31,003	31,003	32,448	32,448
High Load Increase	-	-	*1,444*	*1,444*
Capacity	39,452	39,452	39,452	39,452
BTM Generation	*110*	*110*	*110*	*110*
*Hi Temp Derates**	-	-	-	-
Demand Response	821	411	821	411
Net Firm Imports	29	29	29	29
Transfer Limit	-	1,000	1,000	1,000
Margin (MW)	9,299	9,888	8,855	8,444
Margin (%)	30.0%	31.9%	27.3%	26.0%

Note: All values are MW unless noted.
* Based on an analysis of quantities offered into the day-ahead market on the three hottest days of 2012 and on August 1, 2006. Quantities can vary substantially based on ambient water temperatures, drought conditions, and other factors.

The results in Table 2 are shown separately for the MISO Midwest and South regions. The first column in the table shows the MISO base case, which we believe reasonably reflects expected planning reserves, but with one exception. MISO's base case includes an assumption that MISO will receive full response from its Demand Response (DR) resources (interruptible load and controllable load management) when they are deployed. These resources are not subject to comparable testing procedures as other generating resources, and are granted a 100 percent capacity credit. MISO has rarely deployed these resources, but its limited experience suggests response rate of little more than 50 percent. We recommend that MISO explore reasonable means to derate this capacity under Module E. The "Realistic DR" case in the table reflects the derating of the DR capacity by 50 percent but is otherwise identical to the base case.

The final two columns show the "Full DR" and "Realistic DR" scenarios under peak conditions that are hotter than normal. These columns represent a "90/10" case, which should only occur one year in ten. This is an important case because particularly hot weather can have a significant impact on both load and supply. High ambient temperatures can reduce the maximum output levels of many of MISO's generators, while outlet water temperature or other environmental restrictions cause certain resources to be derated. There is significant uncertainty regarding the size of these derates, so our number in the table is an average of what was observed on extreme peak days in 2006 and 2013. In its Summer Assessment, MISO shows a high-load scenario that includes an estimate of high temperature derates based on the worst year in the past 5 years. While we believe this scenario is a realistic forecast of potential high load conditions, we continue to believe a more realistic assumption of derates that may occur under high-temperature conditions is needed.

The results in the table show that the capacity surplus varies considerably depending on the various assumptions made. The planning reserve margin in the South Region is substantially higher than the planning reserve requirement under all scenarios, but this is not true for the Midwest Region. The baseline capacity margin for the MISO Midwest region is 19.8 percent, which substantially exceeds the Planning Reserve Margin Requirement of 14.8 percent.[6] However, employing a more realistic assumption regarding the response of DR resources reduces the apparent surplus by 2.4 percentage points, but continues to indicate that MISO will be adequate this summer under normal summer conditions.

The high-temperature cases show much lower margins—as low as 6.8 percent when DR is also derated to a realistic level. This is significant because this margin must provide MISO's operating reserves (2,400 MW) and includes no forced outages, which generally range from five to eight percent. Hence, under these conditions, MISO would only avoid firm curtailments by utilizing a combination of non-firm imports and emergency actions.

Overall, these results indicate that the system's resources should be adequate for summer 2014 if the peak demand conditions are not substantially hotter than normal. However, planning reserve margins are gradually decreasing and will likely continue to fall as new environmental regulations are implemented. Therefore, it is important for the resource adequacy provisions to facilitate an efficient capacity market that will provide the necessary economic signals to maintain an adequate resource base. These issues are discussed in detail in the following four subsections.

C. Potential Impact of the New EPA Regulations

MISO continues to study and model the potential impacts of the Environmental Protection Agency's (EPA) Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) on the MISO market. MISO's most recent surveys suggest that 8 to10 GW of capacity in MISO is at risk of retirement because of the compliance costs of these regulations. CSAPR was reinstated in April 2014, and MISO estimates an energy cost impact of $1 to $5 per MWh, mostly in the form of higher variable operations and maintenance costs for control technologies. Additional coal-fired capacity could be at risk of retiring if low natural gas prices continue for the long term. MISO surveys of market participants' compliance plans also indicate

6 The 2014 Planning Reserve Margin Requirement is for all of MISO. Due to the potential transfer limits from South to Midwest and Midwest to South, we have included the firm contract path limit of 1,000 MW in all scenarios. MISO has similarly included this in its Base Case.

substantial amounts of potential retirements and long-term outages related to environmental retrofits.

Together with the increased penetration of wind resources, EPA regulations will put substantial economic pressure on existing coal resources to retire, which should reduce planning reserve margins in MISO. Based on its most recent survey of its participants, most of the affected coal units are planning on implementing the controls required to operate. MISO expects 8.1 GW of the 57 GW of coal-fired units affected by the regulations to retire or suspend, and there are an additional 3.1 GW whose retirement is uncertain. These retirements, together with the increase in capacity exports to PJM, are causing MISO to forecast a capacity deficiency in 2016. The shortcomings in MISO's current RAC will prevent it from performing the key role of providing efficient incentives to resolve this capacity deficiency and supporting reliable planning reserve margins over the long term. Hence, addressing these shortcomings continues to be a high-priority recommendation.

D. Attachment Y and SSR Status Designations

Attachment Y to the MISO Tariff requires suppliers seeking to retire or suspend a unit to notify MISO 26 weeks in advance of its desired date. Based on a reliability study, MISO may then designate a resource as a System Support Resource (SSR), which it granted for the first time in 2012. An SSR cannot retire or be suspended until a reliability solution, such as transmission upgrades, can be implemented or the reliability condition no longer exists. The SSR agreement provides for compensation to the Market Participant during this period of delayed retirement.

In 2013, SSR credits net of market revenues (the portion uplifted to nearby load zones) totaled over $6 million and were paid to 6 units. There are currently 12 units classified as SSR and eligible for up to $6.1 million in gross cost recovery per month. An additional 10 units are under consideration for SSR status by MISO. We will continue to work with MISO on reviewing and, as needed, clarifying these procedures in order to ensure that SSR decisions result in efficient outcomes. As discussed further in the next section, it is also important that the capacity market sends appropriate signals to rationalize participants' decisions to retire or retrofit their resources.

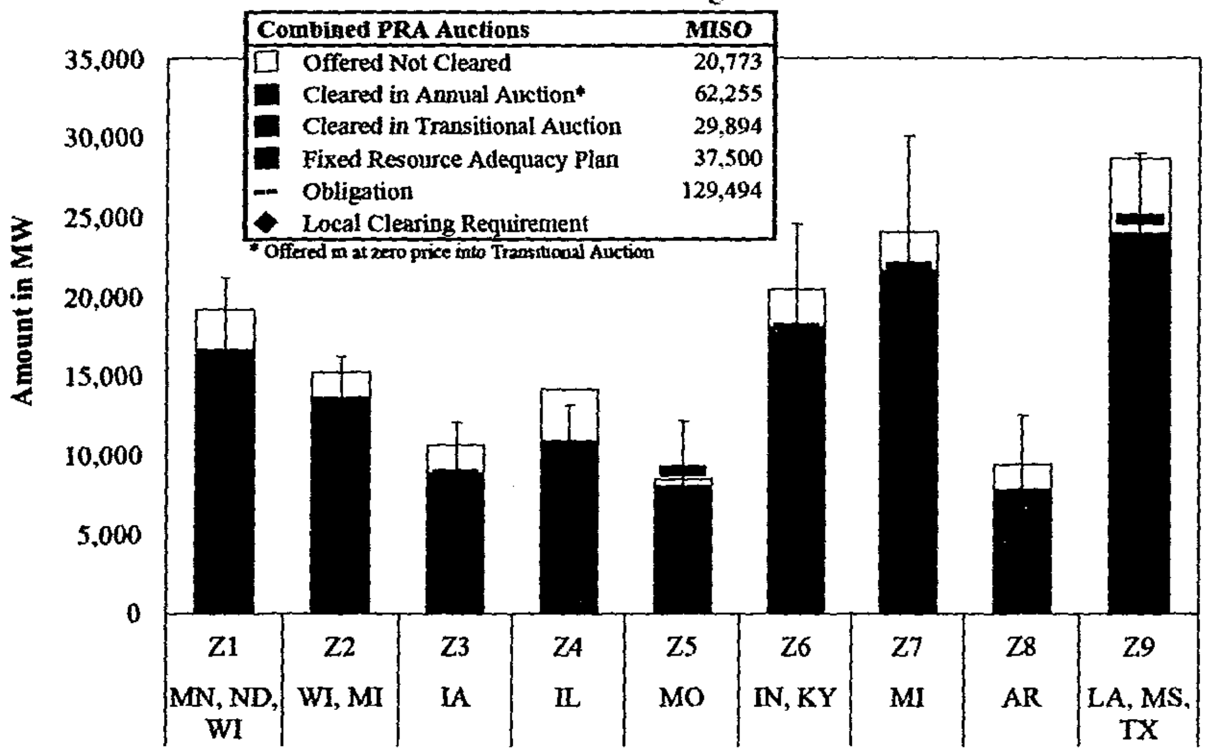
E. Capacity Market

MISO's Resource Adequacy Construct allows LSEs to procure capacity to meet their Module E requirements. Clearing prices in MISO's capacity auctions provide a revenue stream that, in addition to energy and AS market revenues, should signal when and where new resources are needed. In 2013, MISO replaced the monthly VCA with the annual PRA that better reflects regional capacity needs and can cause capacity prices in different zones to diverge when maximum import or exports levels for a zone are reached. This should provide a more accurate signal regarding the value of capacity in various locations.

1. Capacity Market Outcomes

Figure 8 shows the combined outcome of the two PRA auctions held in 2013. A transitional auction was held in November to accommodate the new MISO South Region, with quantities cleared in the April auction offered in at a zero price.

Figure 8: Planning Resource Auctions
2013 – 2014 Planning Year



The figure shows the obligation in each zone, along with the minimum and maximum amount of capacity that can be purchased in each zone. The minimum amount is equal to the obligation minus the maximum level of capacity imports. The auction for the 2013–2014 planning year cleared at $1.05 per MW-day (less than 1 percent of CONE), while the transitional November auction cleared at zero.[7]

2. Capacity Market Design

The performance of the capacity market under the new RAC is undermined by three significant issues: (1) the current "vertical demand curve"; (2) barriers to capacity trading with PJM; and (3) barriers to participation in the auction affecting units with suspension or retirement plans impacting the planning year. The recently modified RAC effectively establishes a vertical demand curve because there is a single minimum capacity requirement for each LSE and a deficiency price for any LSE that is short. Because the marginal cost of selling capacity for most units is close to zero, a vertical demand curve will predictably establish clearing prices close to zero if supply is not withheld. In addition, the vertical demand curve is inconsistent with the underlying reliability value of excess capacity beyond the requirement. The implication of the vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. This is not true in reality—each unit of surplus capacity will improve reliability and lower energy and ancillary services costs for consumers (although these effects diminish as the surplus increases).

To address this flaw, we provided comments to FERC and recommended in prior *State of the Market Reports* that Module E of the Tariff be modified to implement a sloped demand curve.[8] A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions. A sloped demand curve also reduces the incentive to exercise market

7 The most recent PRA, held in March 2014 for the 2014–2015 planning year, cleared at $16.75 per MW-day in all zones except the export-constrained Zones 8 and 9, which cleared at $16.44 per MW-day, and Zone 1, which cleared at $3.29 per MW-day.

8 See "Motion to Intervene Out of Time and Comments of the Midwest ISO's Independent Market Monitor," filed September 16, 2011 in Docket No. ER11-4081.

power—a market that is highly sensitive to withholding and can clear at the deficiency level creates a strong incentive for suppliers to withhold resources to raise prices. Withholding in such a market is nearly costless since the foregone capacity sales would otherwise be priced at close to zero. The need for a sloped demand curve may become particularly acute as planning reserve margins decline toward the minimum requirement level with the likely retirement of significant amounts of coal-fired capacity in MISO as soon as the 2015–2016 planning year.

Load-serving entities and their ratepayers should benefit from a sloped demand curve. LSEs in the Midwest have generally planned and built resources to achieve a small surplus on average over the minimum requirement because:

- Investment in new resources is "lumpy", occurring in increments larger than necessary to match the gradual grow in an LSE's requirement; and
- The costs of being deficient are large.

Under a vertical demand curve, the cost of the surplus must entirely be borne by the LSEs' retail customers because LSEs will generally receive very little capacity revenue to offset the costs that they incurred to build the resources. Since this additional capacity provides reliability value to MISO, the fact that LSEs receive no capacity revenues is inefficient. Adopting a sloped demand curve would benefit most regulated LSEs as we explain below.

Table 3 shows how hypothetical LSEs are affected by a sloped demand curve when they hold varying levels of surplus capacity beyond the minimum capacity requirement. The scenarios assume: (1) an LSE with 5,000 MW of minimum required capacity; (2) net CONE of $65,000 per MW-year and demand curve slope of -0.01 (matching the slope of the NYISO curve); and (3) a market-wide surplus of 1.5 percent, which translates to an auction clearing price of $4.74 per KW-month ($54.85 per KW-year).

For each of the scenarios, we show the amount that the LSE would pay to or receive from the capacity market along with the carrying cost of the resources the LSE built to produce the surplus. Finally, in a vertical demand curve regime where the LSE will not expect to receive material capacity revenues for its surplus capacity, all of the carrying cost of the surplus must be paid by the LSE's retail customers. The final column shows the portion of the carrying cost borne by the LSE's retail customers under a sloped demand curve.

Table 3: Costs for a Regulated LSE Under Alternative Capacity Demand Curves

LSE Surplus	Market Surplus	Capacity Market Revenues ($Million)	Carrying Cost of Surplus ($Million)	Carrying Cost Borne by Retail Load	Surplus Cost: Sloped Demand Curve	Surplus Cost: Vertical Demand Curve
1.0%	1.5%	$-1.43	$3.25	100%	$4.68	$3.25
2.0%	1.5%	$1.41	$6.50	78%	$5.09	$6.50
3.0%	1.5%	$4.25	$9.75	56%	$5.50	$9.75
4.0%	1.5%	$7.10	$13.00	45%	$5.90	$13.00

These results illustrate three important dynamics associated with the sloped demand curve:

1.) *The sloped demand curve does not raise the expected costs for most regulated LSEs.* In this example, if an LSE fluctuates between 1 and 2 percent surplus (around the 1.5 percent market surplus), its costs will be virtually the same under the sloped and vertical demand curves.

2.) *The sloped demand curve reduces risk for the LSE* by stabilizing the costs of having differing amounts of surplus. The table shows that the total costs incurred by the LSE are surplus levels between 1 and 4 percent vary by only 26 percent versus a 300 percent variance in cost under the vertical demand curve.

3.) *A smaller share of the total costs are borne by retail customers.* Because wholesale capacity market revenues play an important role in helping the LSE recover the costs of new resources, the LSE's retail customers will bear a smaller share of these costs when the LSE's surplus exceeds the market's surplus. Under the 3 percent case, for example, the current market would produce almost no wholesale capacity revenue even though the LSE's surplus is improving reliability for the region. Under the sloped demand curve in this case, almost half of the costs of the new unit would be covered by the capacity market revenues.

Hence, although a sloped demand curve could increase costs to non-vertically integrated LSE's that must purchase large quantities of capacity through an RTO's market, the example above shows that this is not the case for the vertically-integrated LSE's that dominate the MISO footprint. In fact, it will likely reduce the costs and long-term risks facing MISO's LSE's in satisfying their planning reserve requirements, in addition to providing efficient market signals to other types of market participants (unregulated suppliers, competitive retail providers, and capacity importers and exporters).

The second issue with MISO's current capacity market is the prevailing barriers to capacity trading between PJM and MISO. Capacity prices in both markets will only be efficient if participants can freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows. Current barriers include a variety of PJM provisions that limit access to transmission, as well as the obligations imposed on external resources that sell capacity into PJM. We described these barriers in detail in number of prior filings to FERC, including comments filed in a recent technical conference FERC held to address capacity market issues in the Northeast, and two sets of comments filed in response to PJM's proposal to introduce Capacity Import Limits (CILs) that would further restrict the ability of external suppliers to export capacity to PJM. We believe the CILs could be a long-term solution to this issue if they are set at reasonable levels and if they replace (rather than supplement) the other barriers to efficient capacity trading. We continue to recommend that MISO work with PJM to address these barriers.

The third issue with MISO's current capacity market relates to the Attachment Y process for suspending or retiring resources. The current market includes inefficient barriers to participation in the PRA for units in suspension or those that have filed under Attachment Y to suspend or retire a resource. These barriers include:

- Suspended units are disqualified from the PRA; and
- Resources that have submitted Attachment Y filings with effective dates during the planning year lose their interconnection rights and cannot satisfy their capacity obligations after the effective date.

In both cases, the PRA should be a process that assists suppliers in making efficient decisions regarding its resource, including whether to bring it back from suspension or to retire or suspend the unit. In order to do this, MISO would need to modify the PRA rules to allow:

- Suspended units to participate in the PRA and to defer the required testing to establish the resource's capacity value in the same manner that new resources or units with catastrophic outages can defer such testing.
- Units with Attachment Y requests to participate in the PRA and, if they clear, to either a) defer the effective date of the retirement or suspension, or to b) retire or suspend the unit during planning year if MISO determines it is not needed during the period when it would be unavailable. Without this flexibility, such units would have to arrange for

substitute capacity for the balance of the planning year and would be out of compliance with the Tariff if they are unable to do so. This risk is an inefficient barrier to participating in the PRA.

These changes to the RAC and the Attachment Y processes will allow MISO's capacity market to operate more efficiently and facilitate better decisions by market participants. The latter change to allow units to be unavailable for a portion of the planning year is consistent with the precedence for several other types of capacity resources that are only available during the summer season, including units that are not winterized, units that operate with PPAs that are considered "Diversity Contracts", and load-modifying resources.

IV. Day-Ahead Market Performance

MISO's spot markets for electricity operate in two time frames: real time and day-ahead. The real-time market reflects actual physical supply and demand conditions. The day-ahead market operates in advance of the real-time market. The day-ahead market is largely financial, establishing financially-binding, one-day-forward contracts for energy and ancillary services. Resources cleared in the day-ahead receive commitment and scheduling instructions based on the day-ahead results.[9] Both the day-ahead and real-time markets continued to perform competitively in 2013.

The performance of the day-ahead market is important for at least three reasons:

- Since most generators in MISO are committed through the day-ahead market, good performance of that market is essential to efficient commitment of MISO's generation;
- Most wholesale energy bought or sold through MISO's markets is settled in the day-ahead market; and
- Entitlements of firm transmission rights are determined by day-ahead market outcomes (i.e., payments to FTR holders are based on day-ahead congestion).

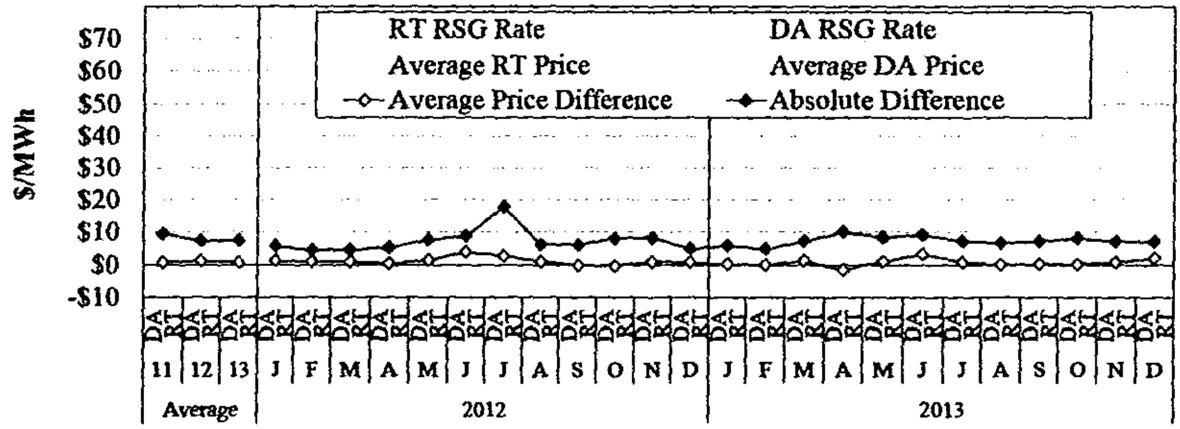
A. Price Convergence with the Real-Time Market

Day-ahead market performance is primarily evaluated by the degree to which its outcomes converge with those of the real-time market because the real-time market reflects actual physical supply and demand for electricity. Participants' day-ahead market bids and offers should reflect their expectations of market conditions for the following day. However, a number of factors, such as wind output volatility, forced generation or transmission outages, and load forecasting errors, can cause real-time prices to be significantly higher or lower than anticipated in the day-ahead. While these factors may limit convergence in a well-performing market on an hourly basis, prices should converge well over longer timeframes (monthly or annually). Figure 9 shows monthly and annual price convergence statistics. The upper panel shows the results for only the Indiana Hub (or Cinergy Hub prior to April 2013), while the table below shows other

9 In between the day-ahead and real-time, MISO evaluates the day-ahead results relative to the forecasted capacity needs for the next day. Based on this Forward Reliability Assessment Commitment (FRAC) MISO may start additional capacity not-committed in the day-ahead.

hub locations. Because real-time RSG charges tend to be much larger than day-ahead RSG charges, the lower table adjusts the average price difference to account for the difference in RSG charges.

Figure 9: Day-Ahead and Real-Time Prices
2012–2013



Average DA-RT Price Difference Excluding RSG (% of Real-Time Price)

	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Cin/Indi Hub	2	4	2	4	3	3	1	5	15	7	3	-1	-1	3	2	0	-1	3	-5	2	10	2	0	0	0	2	6
Michigan Hub	2	4	2	5	2	-1	5	5	7	7	3	4	1	3	1	1	2	5	-5	1	7	-1	0	-2	0	5	7
Minnesota Hub	-2	-2	-1	3	-2	2	-12	-6	0	2	2	-7	3	-8	-1	3	4	4	-7	7	2	-2	-5	-1	-3	-9	-2
WUMS Area	3	1	2	3	0	4	0	-1	-1	2	3	-4	0	0	3	1	4	4	-5	1	6	2	-4	3	1	7	3

Average DA-RT Price Difference Including RSG (% of Real-Time Price)

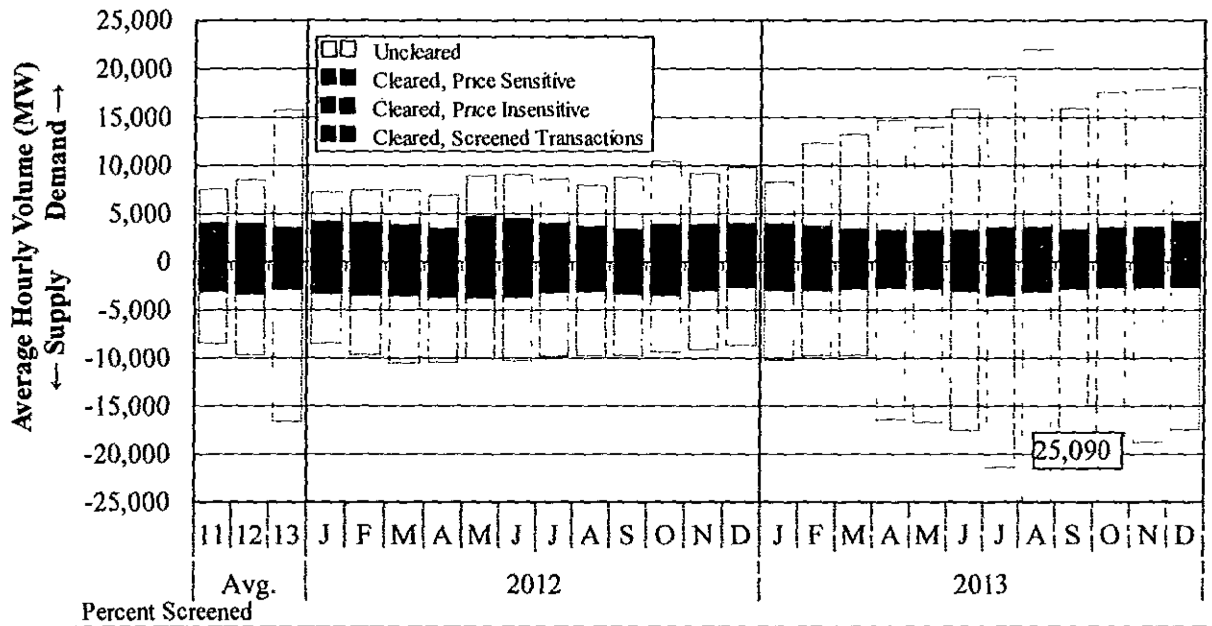
	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Cin/Indi Hub	-1	2	-1	3	2	2	-2	3	12	3	1	-2	-2	0	1	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1
Michigan Hub	-1	2	-1	4	2	-2	2	3	5	4	2	3	0	1	-1	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3
Minnesota Hub	-5	-4	-4	2	-2	1	-14	-8	-3	-2	1	-8	2	-10	-2	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6
WUMS Area	0	-1	-1	2	-1	3	-3	-3	-3	-2	1	-6	-1	-3	1	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1

There were modest day-ahead premiums at most hubs in 2013, including a premium of 1.7 percent at the Indiana Hub. This outcome is expected given the real-time RSG allocated to net real-time purchases and the lower volatility of prices in the day-ahead market. Accounting for the $1.00 per MWh in average RSG cost allocated to real-time deviations from day-ahead purchases (nearly double the level from 2012), the effective average day-ahead premiums disappear. In late spring, operating reserve shortages that were not anticipated in the day-ahead led to substantial real-time premiums. Over the long term, we expect day-ahead load to pay a small premium (net of RSG costs) because scheduling load day-ahead limits the price risk associated with higher real-time price volatility. We discuss RSG costs in greater detail in Section V.C.1.

B. Virtual Transactions in the Day-Ahead Market

Virtual transactions are financial purchases or sales of energy in the day-ahead market that do not correspond to physical load or resources, so they are settled against the real-time price. Virtual transactions are essential facilitators of price convergence because they arbitrage price differences between the day-ahead and real-time markets. Figure 10 shows the average cleared and offered amounts of virtual supply and virtual demand in the day-ahead market. It shows components of daily virtual bids and offers in the day-ahead market in 2012 and 2013. The virtual bids and offers that did not clear are shown as the transparent areas at the end of each bar.

Figure 10: Virtual Load and Supply in the Day-Ahead Market
2011–2013



Percent Screened

Demand	1.6	2.2	2.2	1.5	2.0	1.7	1.6	2.1	4.0	3.1	1.8	2.1	2.2	2.1	2.1	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5
Supply	1.2	1.4	1.2	0.9	1.2	2.4	1.9	2.2	1.4	1.2	1.0	1.2	1.3	1.0	1.4	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3
Total	1.4	1.9	1.8	1.2	1.6	2.0	1.7	2.2	2.9	2.3	1.4	1.6	1.8	1.6	1.8	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1

The figure distinguishes between bids and offers that are price-sensitive and those that are price insensitive (i.e., those that are very likely to clear) because price-sensitive transactions are much more valuable in providing liquidity in the day-ahead market and facilitating price convergence. Bids and offers are considered price-insensitive when they are offered at more than $20 above (demand willing to buy much higher than) and below (supply willing to sell much lower than) an "expected" real-time price.[10] Price-insensitive bids and offers that contribute to a significant difference in congestion at a location between the day-ahead and real-time markets are labeled "Screened Transactions." We routinely investigated these transactions because they are generally not rational and lead to price divergence. Therefore, they may represent an attempt to manipulate the day-ahead market.

The figure shows that offered volumes increased by 79 percent from last year to 32.3 GW. Much of this increase is in volumes by a handful of participants well above (in the case of demand) or below (supply) the expected price range, so they very rarely clear. Such "backstop" bids and offers clear less than one percent of the time, but are substantially profitable when they clear. These transactions are beneficial to the market because they mitigate particularly large day-ahead price deviations. In all, cleared transactions declined by 12 percent, the large majority of which continue to clear at generator locations.

The price-sensitivity of cleared transactions improved modestly in 2013. Nearly two-thirds of all cleared transactions were price-sensitive, up from 60 percent in 2012 and 50 percent in 2011. Price-insensitive volumes are most often placed for two reasons:

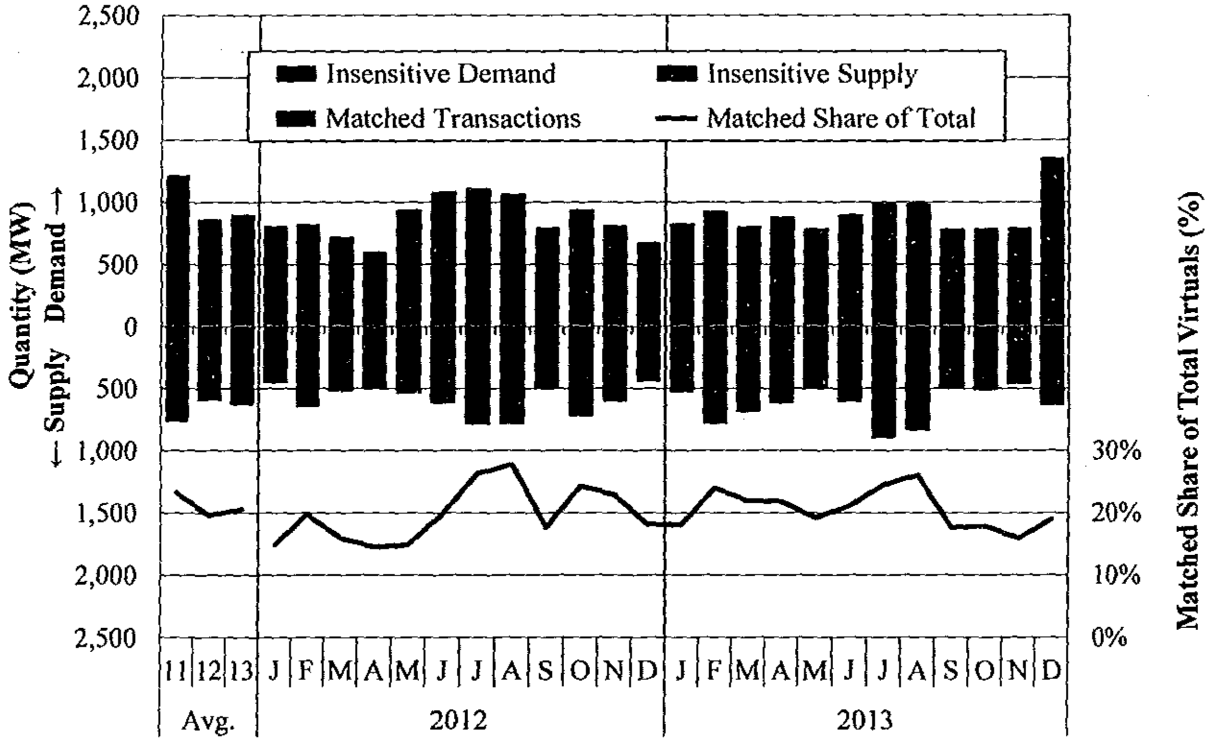
- To establish an energy-neutral position across a particular constraint to arbitrage congestion-related price differences between the day-ahead and real-time markets; and
- To balance the participant's portfolio so as to avoid RSG deviation charges assessed to net virtual supply.[11]

Figure 11 examines more closely these insensitive virtual transactions. "Matched" virtual transactions in the figure are a subset of these transactions whereby the participant clears both insensitive supply and insensitive demand in a particular hour that offset one another. This figure shows that over two-thirds of insensitive transactions and 21 percent of all virtual transactions were "matched" transactions.

10 The "expected" real-time price is based on an average of recent real-time prices in comparable hours.

11 MISO in April 2011 revised its RSG cost allocation measures that generally will reduce the allocation to virtual supply, and eliminate any allocation when virtual supply is netted against a participant's virtual load. This change has increased participants' incentives to clear equal amounts of virtual supply and demand at different locations by submitting them price-insensitively to ensure they clear.

Figure 11: Matched Virtual Transactions
2012–2013



To the extent that matched transactions are attempting to arbitrage congestion-related price differences, we believe that a virtual spread product to allow participants to engage in these transactions price sensitively would be more efficient. Therefore, we are recommending that MISO continue to engage in stakeholder discussions to pursue a virtual spread product. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (i.e., schedule a transaction). The transaction would be profitable if the difference in real-time congestion between the source and the sink is greater than the day-ahead difference. The transaction would lose money if the difference is less. This product would settle only on the difference in the congestion and loss components of the LMP, so the participant would bear no energy price risk and would not create a deviation that could cause MISO to be capacity-deficient. Comparable products exist in both PJM and ERCOT.

C. Virtual Profitability

The rate of gross virtual profitability in 2013 nearly doubled from 2012 to $1.01 per MWh. Demand was unusually profitable compared to prior years, consistent with the increase in periods exhibiting real-time premiums in 2013. Virtual supply profits averaged $1.30 per MWh, nearly unchanged from 2012. However, the real-time RSG costs allocated to net virtual supply under the DDC rate averaged $1.00 per MWh in 2013, which offset most of the net profitability of virtual supply transactions. Low virtual profitability is consistent with a competitive day-ahead market, which means the market efficiently schedules MISO's generating resources.

Transactions by financial-only participants in 2013 continued to be more profitable than those by generation owners and load-serving entities, which is consistent with the conclusion that the arbitrage by financial participants has improved the convergence between day-ahead and real-time prices. Transactions that promote convergence are profitable (e.g., selling virtual supply at high day-ahead prices), while those that lead prices to diverge are unprofitable. Profitability of transactions cleared by physical participants in 2013 was positive for the first time since 2010 because they expressed a lower willingness to incur losses on virtual demand than in prior years.

D. Fifteen-Minute Day-Ahead Scheduling

The day-ahead market currently clears on an hourly basis. As a result, all day-ahead schedule changes occur at the top of each hour. In hours when load is ramping rapidly, the hourly changes in day-ahead load (and scheduled supply to satisfy that load) do not track the changes in real-time load well.

Many participants in the real-time market attempt to match their day-ahead schedules, which can cause severe ramp demands at the top of the hour that can contribute to transitory operating reserve shortages and inflated production costs during these periods. Ramp demands are caused by unit commitments, de-commitments, and changes to physical schedules that are all concentrated at the top of the hour. Solving the day-ahead market more frequently would result in more flexible commitments and schedules that could better align with actual ramp demands in the real-time. Computer hardware performance limitations previously prevented MISO from adopting such a granular day-ahead market. However, performance has improved significantly over time and should continue to improve in the future. Therefore, as MISO considers its longer-term market improvements and priorities, we recommend it evaluate the costs and benefits of modifying the day-ahead market to clear on a fifteen-minute basis.

V. Real-Time Market

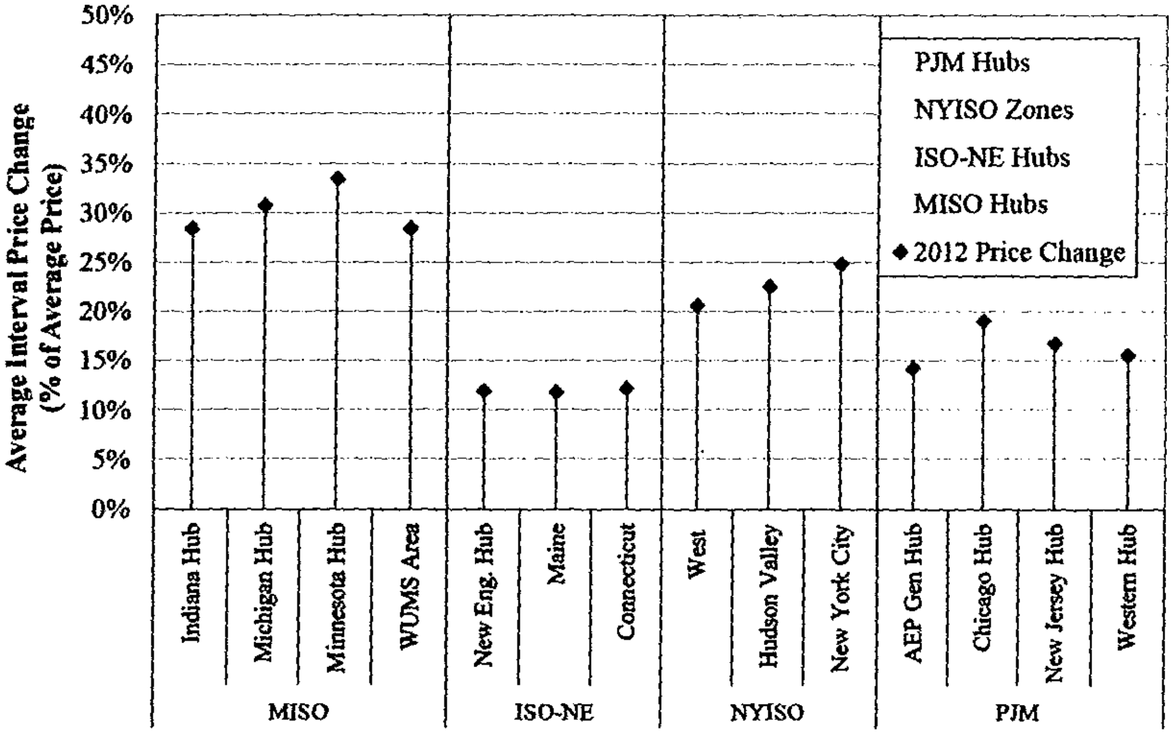
A. Real-Time Price Volatility

Substantial volatility in real-time energy markets is expected because the demands of the system can change rapidly, and supply flexibility is restricted by the physical limitations of the resources and the transmission network. In contrast, the day-ahead market operates on a longer time horizon with more commitment options and liquidity provided by virtual transactions.

MISO's real-time market operates on a five-minute time horizon. Hence, when conditions change, the real-time market only has access to the dispatch flexibility that its units can provide in five minutes. Since the real-time market software is limited in its ability to "look ahead" and anticipate near-term needs, the system is frequently "ramp-constrained" (i.e., some generators are moving as quickly as they can up or down). This limitation results in transitory price spikes, either upward or downward. This section evaluates the volatility of the real-time energy prices.

Figure 12 compares fifteen-minute price volatility at representative points in MISO and in three neighboring RTOs. Volatility in MISO rose to $5.71 per interval, which is 10 percent higher than in 2012. This increase is largely due to the higher fuel prices in 2013; volatility after accounting for the fuel price changes was slightly lower in 2013 than 2012. However, price volatility in MISO remains considerably higher than in neighboring RTOs primarily because MISO runs a true five-minute real-time market (producing a new real-time dispatch every five minutes). PJM and New Enlgand ISO dispatch their systems every 10 to 15 minutes, which tends to provide more flexibility (which lowers volatility). However, by producing new dispatch instructions less frequently, an RTO must rely more heavily regulation to balance supply and demand between intervals. NYISO dispatches the system every 5 minutes like MISO, but it has a look-ahead dispatch (LAD) system that optimizes multiple intervals. The multi-period optimization reduces price volatility.

Figure 12: Fifteen-Minute Real-Time Price Volatility
2013



The volatility in MISO occurs when ramp constraints bind and cause sharp price movements, which tends to happen when:

- Actual load is changing rapidly, including non-conforming load associated with industrial facilities that can change sharply and without advance notice;
- Net Scheduled Interchange (NSI) changes significantly;
- A large quantity of generation is either starting up or shutting down; or
- The load-offset parameter is not set optimally to manage anticipated ramp changes.

In recent years, MISO has improved the efficiency of real-time commitments with the introduction of the Look-Ahead Commitment (LAC) tool. MISO is currently developing a ramp capability product that will cause the real-time market to hold ramp capability when possible at a low cost that will improve its ability to manage the system's ramp demands. We believe this product will be beneficial and continue to recommend its adoption. It is currently scheduled for deployment in September, 2015. We also support MISO's decision to evaluate the incremental benefits of a LAD tool after deployment of the ramp product.

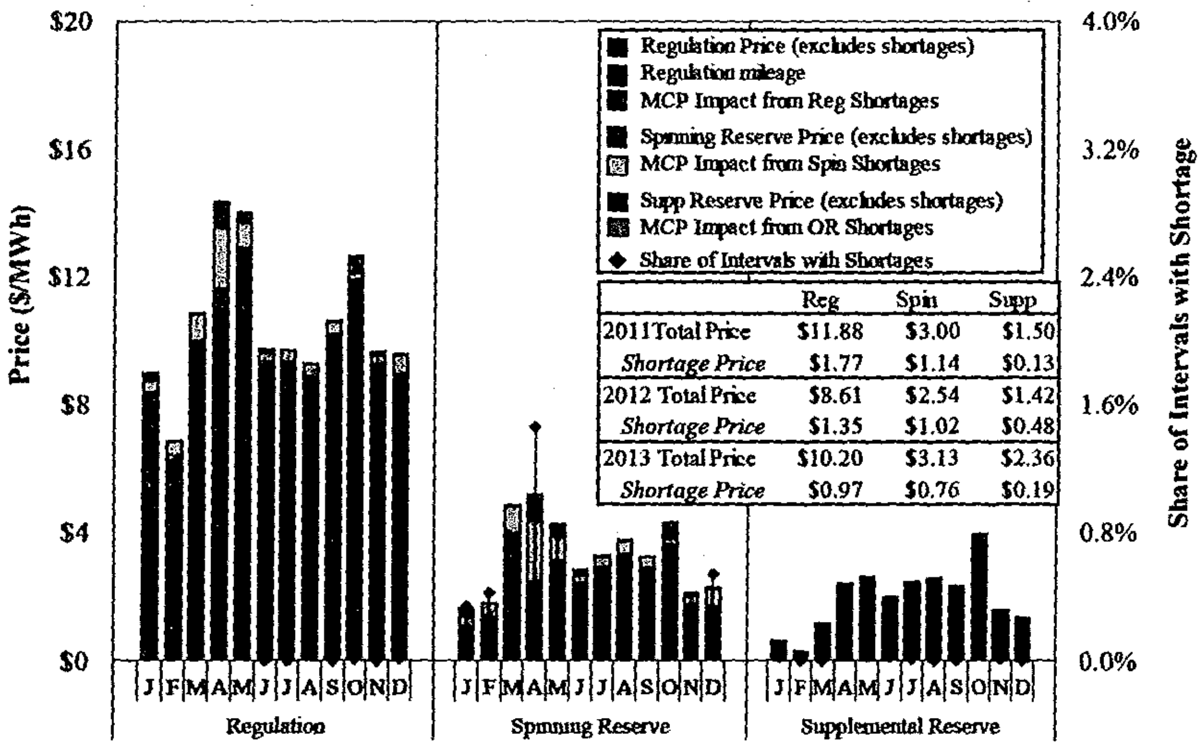
B. Ancillary Services Markets

ASM continued to perform as expected with no significant issues in 2013. Since their inception in 2009, jointly-optimized ancillary services markets have produced significant benefits, leading to improved flexibility and lower costs of satisfying the system's reliability needs. These markets have also facilitated more efficient energy pricing that reflects the economic trade-off between reserves and energy, particularly during shortage conditions.

Figure 13 shows monthly average real-time prices for regulation, spinning reserves, and supplemental reserves, along with the contribution of shortage pricing to each product's clearing price in 2013. It also shows the share of intervals in shortage for each product. MISO uses demand curves to specify the value of all of its reserve products. When the market is short of one or more of its ancillary service products, the demand curve for that product(s) will set the price and be included in the prices of higher-valued reserves and energy. The demand curve penalty price for regulation in 2013 averaged $182 per MWh. The spinning reserve penalty price was unchanged at $65 per MWh (for shortage quantities of less than 10 percent of the reserve requirement) and $98 per MWh (for those in excess of 10 percent). MISO introduced a new Operating Reserve Demand Curve in May 2013 that prices the first four percent of an operating reserve shortage at $200 per MWh. More significant shortages are priced from $1,100 to $3,400 per MWh depending on their severity.

The supplemental reserve prices in this figure shows the price associated with satisfying MISO's market-wide operating reserve requirement. This is the only requirement that supplemental reserves can satisfy. Because a spinning reserve resource can satisfy both the operating reserve requirement and the spinning reserve requirement, the spinning reserve price will include a component associated with operating reserve shortages. In other words, shortages of operating reserves will be included in the price of supplemental reserves and all higher-value products, including energy. Likewise, the higher-value regulation product includes components associated with spinning and operating reserve shortages.

Figure 13: ASM Prices and Shortage Frequency
2013



Monthly average clearing prices for all products rose in 2013 because the opportunity costs of providing ancillary services increased with as energy prices increased:

- Regulating reserve prices rose 19 percent to $10.20 per MWh in 2013;
- Spinning reserve prices rose 23 percent in 2013 to an average of $3.13 per MWh; and
- Supplemental reserve prices rose 68 percent to $2.36 per MWh.

The impact of higher energy (and opportunity costs) was offset by the substantial reduction in shortages in 2013, particularly in the summer. Although reduced from 2012, shortage pricing was most significant in the spring. In April, 126 intervals of spinning reserve shortages and 6 intervals of operating reserve shortages were primarily due to factors that increased the ramp demands of the system. These are magnified in lower-load shoulder seasons because MISO often has fewer units online capable of providing ramp capability and may have fewer offline reserves due to increased planned outage levels. Shortage pricing in 2013 accounted for less than 10 percent of the average regulation and supplemental clearing prices, but nearly 25 percent of the average spinning reserve clearing price.

In late 2012, MISO introduced a new payment for "regulation mileage". The mileage payment pays resources for actual response during regulation deployments. The total regulating reserve clearing prices (payments for both Regulating Mileage and Regulating Capacity) in 2013 were not materially impacted by the new "regulation mileage" compensation formula. Although some participants' regulation offer prices rose considerably after this change due to a general lack of familiarity with the offer structure, it had a limited impact on clearing prices after January.[12]

1. Lost Capacity During Supplemental Reserve Deployments

In evaluating the performance of the MISO markets during shortage conditions, we detected a flaw that occurs when quick-start units are deployed. Offline quick-start resources (e.g., combustion turbines and pumped storage resources) can provide supplemental reserves that satisfy MISO's contingency reserve requirement. When resources providing supplemental reserves are committed, the reserves they were providing are shifted to online resources.

Unfortunately, MISO does not account for the committed resource as providing reserves or energy until the unit is fully synchronized and providing energy. Hence, all capacity from the resource will appear to be lost in the interim, generally for five to 15 minutes. During this period, the quality of reserve capability is actually enhanced because the resource can provide energy and reserves more quickly to the system once it is online.

In 2013, lost reserve capability from committed quick-start resources affected a smaller number of intervals because MISO sought to avoid starting units that have been scheduled for offline reserves. The issue, however, caused four operating reserve shortages and contributed to at least five periods of operating reserve price spikes of at least $100 per MWh. This issue also increased DAMAP during the reserve shortage events by nearly $500,000. Therefore, we continue to recommend MISO pursue changes in its accounting of reserves that would recognize the reserves being provided during the period when a quick-start unit is starting.

12 The chart does not reflect the additional uplift costs associated with charging back the clearing price to resources for undeployed mileage based on actual energy withdrawals. These costs totaled $1.84 million in 2013.

C. Settlement and Make-Whole Payments

MISO employs two primary forms of make-whole payments in real time to ensure resources cover their as-offered costs and, therefore, have incentives to be flexible:

- RSG payments ensure that the total market revenue a generator receives when economically committed is at least equal to its as-offered costs over its commitment period.
- PVMWP ensure that suppliers will not be financially harmed in the hourly settlement by following MISO's five-minute dispatch signals. The PVMWP consists of two payments: Day-Ahead Margin Assurance Payments (DAMAP) and Real-Time Offer Revenue Sufficiency Guarantee Payments (RTORSGP).

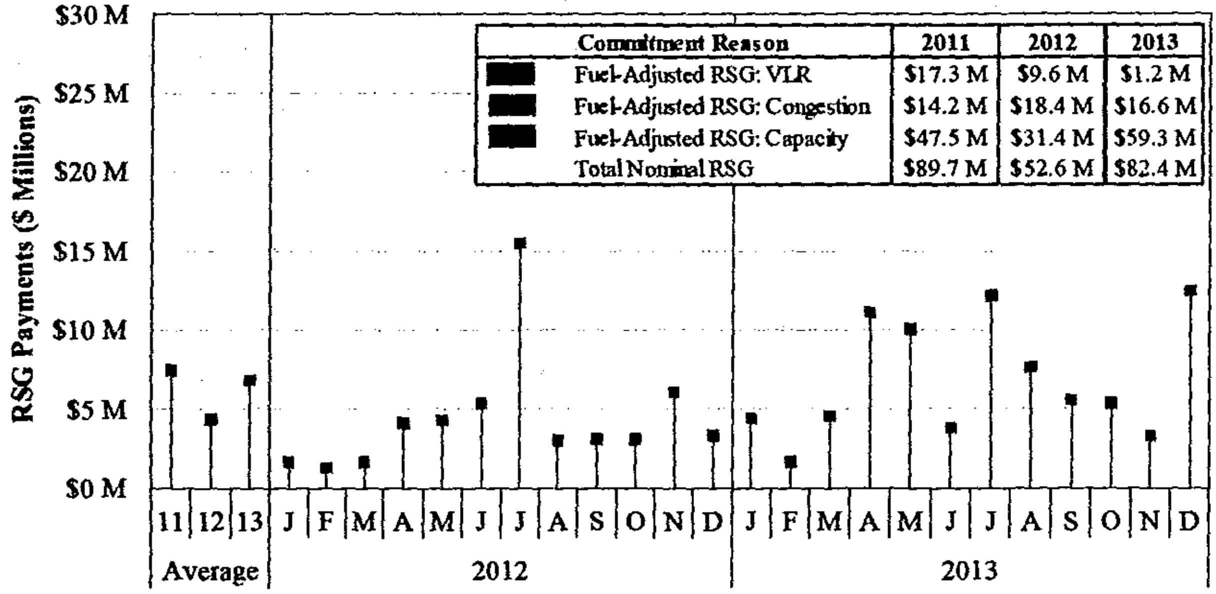
Resources committed by MISO for economic capacity or for congestion management after the day-ahead market receive a "real-time" RSG payment if their as-offered costs are not recovered through the LMP in the real-time market. The costs related to RSG payments are recovered via charges that are "uplifted" to market participants. It is most efficient to allocate RSG costs to market participants in proportion to how much they contribute to causing the costs.

1. Real-Time RSG Costs

Figure 14 shows monthly real-time RSG payments for the last two years. Real-time RSG payments tend to be higher than day-ahead RSG payments because the day-ahead market has greater liquidity provided by virtual transactions and greater generation flexibility. Since fuel prices have considerable influence over suppliers' production costs, the figure shows real-time RSG payments in both nominal and fuel-adjusted terms.[13] It separately shows the fuel price-adjusted RSG payments associated with commitments made for capacity purposes, local voltage support, and constraint management. The table below the figure shows the share of RSG costs paid to peaking and non-peaking resources. Peaking resources are generally high-cost, inflexible resources relied upon in real time to meet system reliability needs, particularly in summer.

13 Fuel-adjusted RSG payments are indexed to the average three-year fuel price of each unit. Downward adjustments are therefore greatest for periods when fuel prices were highest, and vice-versa.

Figure 14: Real-Time RSG Payments
2012–2013



Share of Real-Time RSG Costs by Unit Type (%)

Peaker	60	68	76	29	31	27	43	73	65	82	42	68	71	74	76	82	56	75	81	76	74	85	81	73	50	63	80
Non-Peaker	40	32	24	71	69	73	57	27	35	18	58	32	29	26	24	18	44	25	19	24	26	15	19	27	50	37	20

Real-time nominal RSG costs rose 54 percent from 2012 to $81 million. Nearly one-half of this increase is due to the significant rise in fuel prices. After adjusting for the fuel price increase, payments rose 30 percent compared to last year. Capacity-related real-time RSG payments increased the most and accounted for three-quarters of all payments. Lower load-scheduling in the first half of 2013 (relative to the over-scheduling observed in the same period in 2012) resulted in MISO committing a larger number of units in real time, particularly in April. Payments for commitments to resolve congestion declined 10 percent to a fuel-adjusted $16.6 million. The largest payments were related to outages, notably in October when much of the $2.3 million in payments were made to expensive oil-fired units.

Payments to units committed for Voltage and Local Reliability (VLR) support, which used to be made primarily in real time, were mostly shifted to the day-ahead market in September 2012. Hence, real-time VLR payments declined to just $1.2 million.

Significant local market power can exist when MISO must commit resources to resolve transmission constraints. In late 2013 and early 2014, RSG payments associated with increases in suppliers' offer prices have increased substantially, which raise concerns regarding the effectiveness of the current RSG mitigation measures. Based on our evaluation of these results, we are proposing to modify the current RSG mitigation measures to adopt a framework comparable to the framework applied to mitigate the RSG dollars paid to resources committed for VLR requirements. This proposal is presented in Section VIII.D.

2. Real-Time RSG Cost Allocation

In April 2011, MISO implemented a revised RSG cost allocation methodology to recognize that MISO commits resources to meet either system-wide capacity needs or to manage congestion or local voltage needs. It subsequently modified the allocation in September 2012 to more directly allocate the costs of satisfying local voltage needs to local areas.

The remaining capacity and congestion-related RSG costs are allocated based on market participants' real-time net deviations from day-ahead schedules that cause each type of commitment. In particular, when deviations:

- Contribute to congestion on specific constraints, costs are collected via the Constraint Management Charge (CMC) rate; and/or
- Contribute to a market-wide capacity need, costs are collected via the Day-Ahead Deviation and Headroom Charge (DDC) rate.

The balance of the real-time RSG costs not already allocated to DDC- or CMC-related deviations is charged to load on a load-ratio share basis known as "Pass 2". In the 2012 *State of the Market Report*, we evaluated the allocation of real-time RSG and concluded that the costs were not being allocated to the actions that were causing the RSG payments. Because this allocation continued in 2013, the results were comparable to 2012.

Real-time RSG charges totaled $81.1 million in 2013, over 91 percent of which was allocated to deviations under the market-wide DDC rate even though market-wide deviations do not cause most of the real-time RSG payments. The excess level of costs allocated under the DDC rate occurred because:

- Helping deviations were not netted against harming deviations in determining the extent to which the deviations caused the RSG payments; and

- $15 million of RSG costs incurred to manage congestion were allocated under the DDC rate.

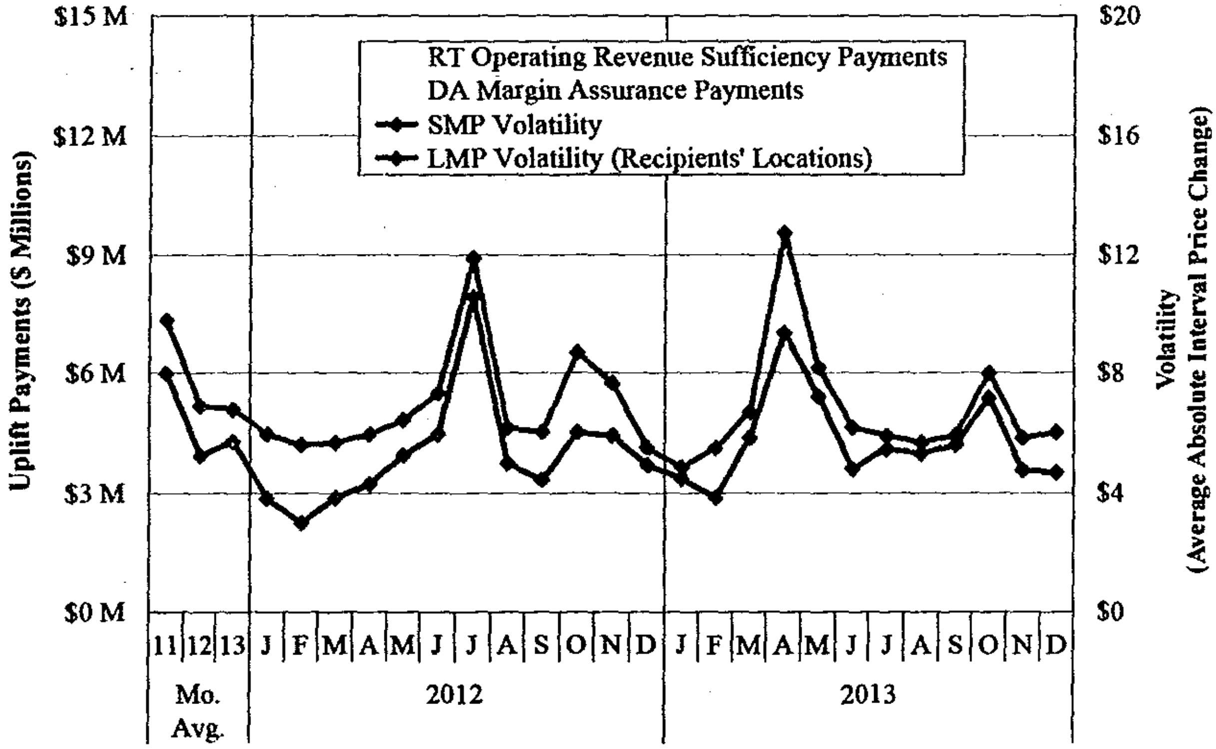
We proposed a series of changes to address these issues and MISO filed the changes in 2013. FERC approved most of these changes and they were implemented in March 2014, although FERC reject one proposed change because it found that MISO's evidentiary support was insufficient. This proposed change involves allocating real-time RSG costs to helping deviations that occur after the notification deadline (NDL). These deviations do not directly cause real-time RSG, but in fact likely reduce real-time RSG by reducing the commitments made by LAC (which runs after the NDL) and the MISO operators. Including these deviations reduces the rate that should be allocated to the deviations that do cause RSG and, in doing so, undermines the economic incentive that should deter the conduct that causes RSG. MISO is planning on re-filing the proposed change in a future FERC filing with additional evidence and analysis for this proposal.

3. Price Volatility Make-Whole Payments

PVMWP address concerns that, under the current hourly-settlement process, resources that respond flexibly to volatile five-minute price signals can lose profits or incur losses. Hence, these payments provide suppliers the incentive to offer flexible physical parameters and follow dispatch instructions.

Figure 15 shows that the total of the two components of PVMWP declined 10 percent from 2012 to $55.5 million, of which over 80 percent was in the form of DAMAP. DAMAP payments are made when generators are dispatched below their day-ahead schedule and below the level that is economic given the hourly settlement price and their offer prices. Hence, when transitory volatility causes a unit to be dispatched downward and the supplier would be economically harmed based on the hourly average energy price, a DAMAP payment is made. Conversely, the RTORSGP is made when a unit is dispatched above the level that would be economic given the hourly energy price.

Figure 15: Price Volatility Make-Whole Payments
2012–2013



The figure shows that the PVMWPs are correlated with changes in volatility, particularly the volatility in LMP at the resources' locations. This volatility was highest in April due to significant spinning and operating reserve shortages, which resulted in the second highest level of payments in 2013. Payments continued to be paid predominantly to flexible coal units during ramping hours.

4. Unreported Derates

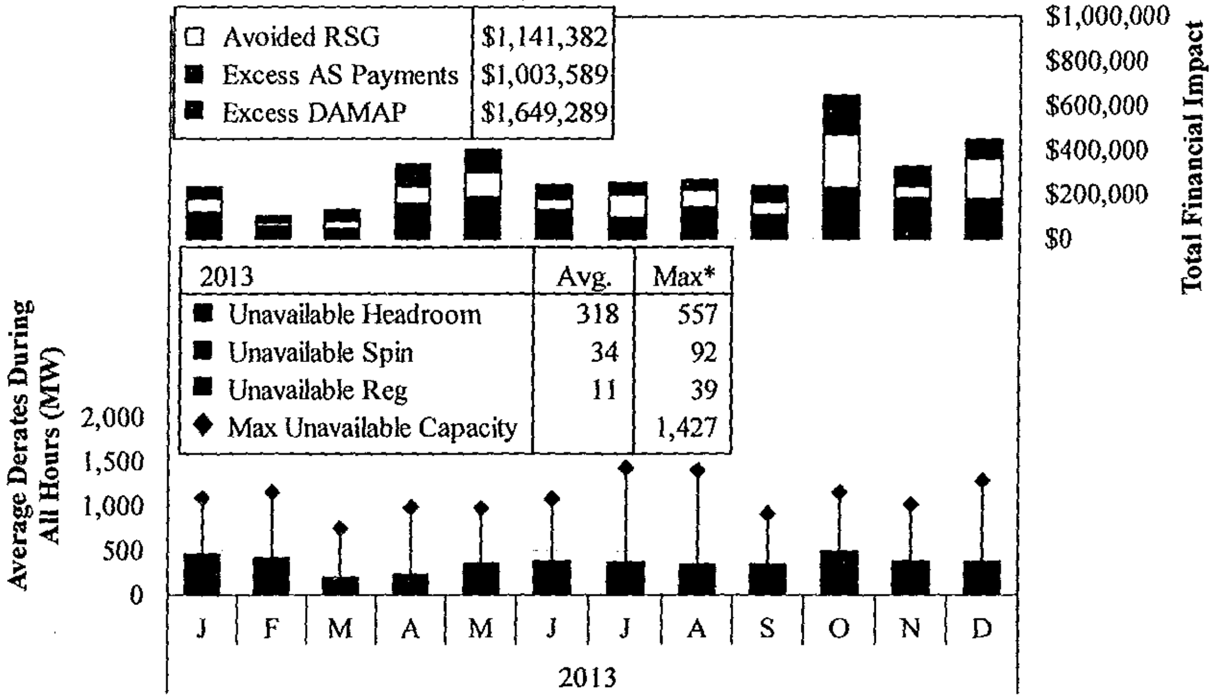
In the past two years, we have made a number of referrals to FERC regarding resources that were inappropriately paid DAMAP for energy sold day-ahead but unavailable in real time because the unit was unable to respond to setpoints. The resources remained eligible for payments in real time because they did not update their real-time offers to reflect the derated capacity. As discussed in our 2012 *State of the Market Report*, PVMWP eligiblity rules do not adequately identify when a unit is "dragging" or otherwise not following MISO's dispatch instructions. This causes:

- MISO to make PVMWPs to resources that are not providing the benefits for which the payments are intended;
- MISO to make payments for reserves that are not truly available;
- The supplier to avoid being allocated real-time RSG it would have been allocated if it derated its resource; and
- Potential reliability impacts because MISO's regional generation dispatch (RGD) procedures and tools are not designed to detect such unreported derates.

Figure 16 shows the monthly average quantity of unreported (or "inferred") derates. The bottom panel shows the average and maximum quantities of derates we identified, separated by capacity scheduled for regulation, spinning reserves, or simply providing headroom (latent reserves) in the energy market. The top panel shows the financial impacts of this conduct in the form of unjustified DAMAP and ASM payments, as well as RSG charges that the suppliers avoided by not updating their real-time offer parameters.

This figure shows that the quantities of inferred derates averaged 363 MW per hour in 2013, and exceeded MISO's headroom requirement (generally 750 MW) in approximately five percent of all intervals. Significant derates can substantially reduce MISO's ability to maintain reliability because these unreported derates can cause it to overestimate the amount of capacity it has available.

Figure 16: Unreported ("Inferred") Derates
Daily Peak Hours, 2013



* Daily Average Maximum

Including the effects of payments for reserves and PVMWPs, as well as avoided RSG charges, units with inferred derates in 2013 received more than $4 million in economic benefits while potentially undermining reliability. Because the failure to update a resource's real-time offers constitutes a violation of MISO's Tariff and a "market violation" as defined by FERC, we have made a number of referrals to FERC's Office of Enforcement regarding significant unreported deratings.

While some of the derates are reported in MISO's Control Room Operating Window (CROW) system, this system is not used to validate, benchmark, or update unit offers in the real-time market system used for dispatch. MISO staff furthermore do not have necessary tools to identify in real-time unreported derates that are the result of the failure to follow dispatch over multiple intervals.

To address these concerns, we recommended several changes in last year's *State of the Market Report*, including improving screening for such derates and tightening the tolerances for uninstructed generator deviations. MISO has begun implementing several new operating procedures, the first of which is expected to be implemented in the second quarter of 2014. While these procedures are not final, we still have concerns that the new tools may not detect signficant unreported derates.

In this report, we recommend a new standard for identifying uninstructed deviations that could be used in the settlement of excess and deficient energy, as well as in the eligibility rules for the PVMWPs.[14] MISO has also filed revised eligibility rules in October 2013 that we had previously recommended to eliminate gaming opportunities related to PVMWP. FERC accepted these proposals and they have been implemented by MISO.

5. Five-Minute Settlement

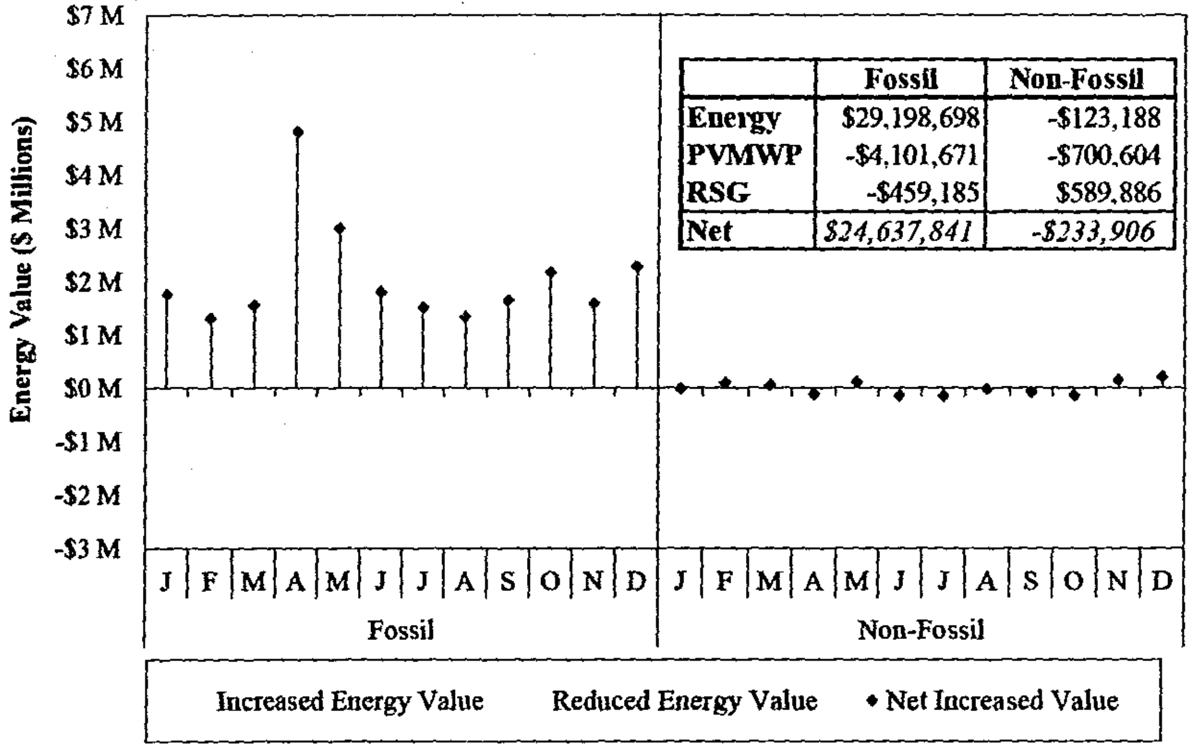
MISO produces new dispatch signals and prices every five minutes, but settles with generators and physical schedulers on an hourly basis using an average of the five-minute prices. This can create inconsistencies between the dispatch signal and the hourly prices that can create incentives for generators to not follow the dispatch signal or to simply be inflexible. To address these inconsistencies, MISO introduced the PVMWPs described above.

The PVMWPs have been effective at eliciting additional flexibility from MISO's resources. However, it is a poor substitute for a true five-minute settlement where each generator, importer, or exporter would settle based on the actual value of energy corresponding with its production or transactions in each five-minute interval.

Figure 17 shows the increases and decreases in energy settlements that would occur under a five-minute settlement (relative to the current hourly settlement) for fossil fuel-fired and non-fossil fuel-fired resources.

14 An evaluation of generator deviations and the description of the new proposed standard can be found in Subsection 6 below.

Figure 17: Net Energy Value of Five-Minute Settlements
2013



	Fossil	Non-Fossil
Energy	$29,198,698	-$123,188
PVMWP	-$4,101,671	-$700,604
RSG	-$459,185	$589,886
Net	*$24,637,841*	*-$233,906*

Fossil fuel-fired resources in 2013 produced $24.6 million more in actual energy value than was reflected in their settlement revenues. The increased energy value was consistent across the year, peaking at over $5 million in April when units were responding to price spikes produced by shortages. Approximately 14 percent of this lost value was paid to resources in the form of PVMWP. Combustion turbines were particularly affected, losing $3.5 million or $0.42 per MWh. Non-fossil fuel-fired resources were paid nearly the same in hourly energy revenues as their actual five-minute energy value. This is a marked change from 2012 when such resources were paid nearly $5 million in excess of their value.

The fact that fossil fuel-fired units would receive more revenue and non-fossil ones would likely receive less is consistent with the fact that flexible, controllable resources are more valuable to the system and, therefore, would benefit from a more granular settlement. Fossil fuel-fired resources tend to be more flexible for following load and prices and, therefore, tend to produce more in intervals with higher five-minute prices. Some non-fossil-fuel types such as nuclear provide little dispatch flexibility so the average output across a given hour is consistent and seldom results in any discernible difference in valuation. Wind resources, conversely, can only respond to price by curtailing in the downward direction. Normally they cannot ramp up in response to higher price. Additionally, wind resource output is negatively correlated with load and often contributes to congestion at higher output levels, so hourly-integrated prices often overstate the economic value of wind generation.[15]

These results show there are substantial discrepancies between the actual value of energy on a five-minute basis and settlements currently made on an hourly basis. The PVMWPs alone are not sufficient to address these discrepancies. Hence, our five-minute settlement recommendation will improve the incentives for generators to follow dispatch instructions, provide more flexibility, and provide incentives for participants to schedule imports and exports more efficiently. We continue to recommend MISO evaluate the feasibility of implementing a five-minute settlement. MISO is evaluating the feasibility of this change both in response to this recommendation and because it is one way to facilitate more accurate settlements with physical transactions and shorten scheduling timeframes as required by FERC's Order 764.

6. Generator Deviations

MISO sends energy base-point instructions to generators every five minutes identifying the expected output at the end of the next five-minute interval. It assesses penalties for deviations from this instruction when deviations remain outside an eight percent tolerance band for four or more consecutive intervals within an hour.[16] The purpose of the tolerance band is to permit a level of deviations that balances the physical limitations of generators with MISO's need for units to accurately follow dispatch instructions. MISO's criteria for identifying deviations are significantly more lenient than most other RTOs.

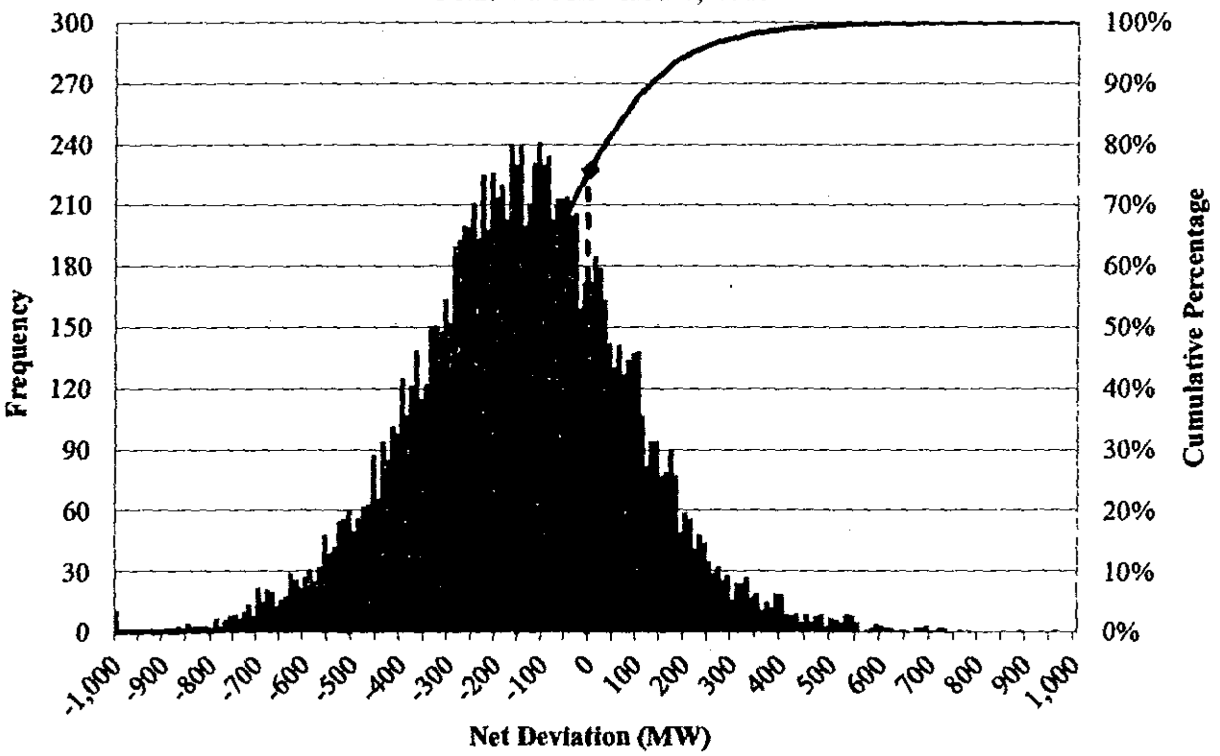
The average gross negative deviation in 2013 was 545 MW, while gross positive deviations averaged 502 MW. Two-thirds of these deviations occur when the system is ramping rapidly up

15 The contribution of RSG payments to non-fossil fuel-fired units (shown in the table) results from excess energy payments to pumped storage resources due to the hourly-integrated settlement. A reduction in energy payments would be offset by an increase in RSG payments since these units are often committed economically by MISO and thus eligible for production cost recovery.

16 See Tariff Section 40.3.4.a.i. The tolerance band can furthermore be no less than 6 MW and no greater than 30 MW. This minimum and maximum was unchanged for this analysis.

or down. Net deviations are small in many periods, but they tend to be considerably greater when loads are highest. Figure 18 shows the frequency of net deviations (absent any tolerance band) during peak hours in summer months in 2013.

Figure 18: Frequency of Net Deviations
Peak Summer Hours, 2013



MISO was net deficient (generators collectively producing less than instructed) in over 75 percent of all peak summer intervals. The median deficiency was 151 MW and exceeded 500 MW in over six percent of the intervals (this share exceeded 15 percent during the top 10 load days). Significant net negative deviations can contribute to shortages because of limited availability of other resources to compensate for the negative deviations.

MISO currently deems a generator to be incurring an uninstructed deviation only when it is more than eight percent above or below its dispatch instruction for four consecutive intervals. This exempts the vast majority of deviation quantities from significant settlement penalties. This is the most tolerant criteria of any RTO, most of which employ a five percent band with no consecutive interval criteria. The looseness of this band allows resources to effectively derate themselves by simply not moving over many consecutive intervals. So long as the dispatch instruction is not eight percent higher than its current output, a resource can simply ignore its dispatch instruction. Unfortunately, because it is still considered to be on dispatch, it can receive unjustified DAMAP payments and avoid RSG charges it would otherwise incur if it were to be derated.[17]

In our *2012 State of the Market Report,* we recommended that MISO tighten the tolerance bands for uninstructed deviations (Deficient and Excessive Energy). In this report, we recommend a specific approach for establishing the tolerance bands that would be more effective at identifying units that are not following dispatch. This approach is based on units' ramp rates, which has a number of advantages compared to the current output-based thresholds:

- The threshold will be the same regardless of the output level (ability to follow dispatch does not change as the output level increases);
- It will more readily identify units who are not responding to dispatch signals (resources that do not move, or move in opposition to the dispatch instruction will be identified);
- Making thresholds proportional to offered ramp rate will eliminate the current incentive to provide an understated ramp rate; and
- Output-based thresholds enable a resource to avoid being flagged for not following dispatch if it offers low ramp rates.[18]

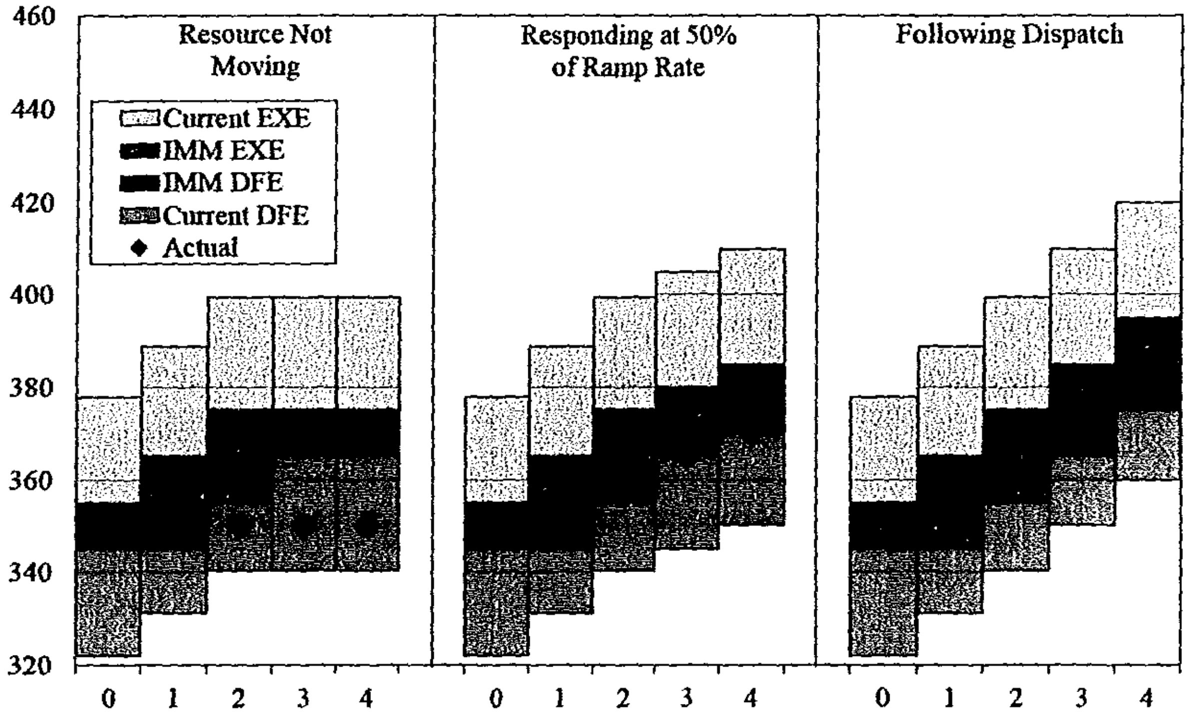
The threshold calculation we propose equals one-half of the resource's five-minute ramp capability plus a value that corresponds to the set point change for the direction in which the unit is moving (i.e., set point change included for deficient energy when the unit is moving up and for excess energy when the unit is moving down). This provides increased tolerance only in the ramping direction so units that are dragging slightly or responding with a lag will not violate the threshold. Additionally, since the current thresholds require that a unit fail in four consecutive intervals, the IMM proposed threshold would similarly require that a resource be unresponsive for four consecutive intervals before it would be considered to be deviating or not following dispatch.

17 This issue was discussed above in Section V.C.3.

18 The current minimum ramp rate for PVMWP eligibility is 0.5 MW per minute.

Figure 19 illustrates how these thresholds would be calculated and applied in three cases. Each of the cases assumes a unit that has been operating at 350 MW, has a 2 MW-per-minute ramp rate, and is receiving dispatch instructions to increase output at its ramp rate. In the first case, the unit is not moving. In the second and third cases, the unit is ramping up at 50 percent and 100 percent of the unit's ramp rate. The lighter areas are the existing thresholds while the darker areas are our proposed thresholds.

Figure 19: Proposed Generator Deviation Methodologies



This figure shows that when the resource is not moving, it will fail the IMM proposed threshold in the second interval if it is being instruction to increase its output as fast as its ramp rate allows. In contrast, this unit can be completely unresponsive in all four intervals and not exceed the current deficient energy threshold. This highlights a substantial concern with the current thresholds.

The figure also shows that if the unit moves in the direction of the dispatch instruction at 50 percent of its ramp rate, it will not fall outside our proposed tolerance band (it will be at the very bottom of the deficient energy range). Finally, when a unit is moving at its ramp rate (at the level of the dispatch instruction), it will have a wider deficient energy tolerance threshold because the unit is moving upward.

D. Dispatch of Peaking Resources

The dispatch of peaking resources is an important component of the real-time market because peaking units are a primary source of RSG costs and a critical determinant of efficient price signals. The average hourly dispatch of peaking resources declined 34 percent in 2013 to average 443 MW. Fewer periods of extreme heat reduced peaking resource needs by nearly 70 percent in July 2013 compared to July 2012. In addition, lower peak loads and higher natural-gas prices in 2013 made far fewer peaking resources economic in the day-ahead market. Since peaking resources frequently do not set energy prices in the real-time market, the share of peaking resources dispatched in economic merit order in 2013 was 49 percent.

A peaking resource dispatched out-of-merit does not indicate that the unit was committed inappropriately. Rather, it simply indicates that the LMP was set by a lower-cost resource (peaking units operating at their economic minimum or maximum are ineligible to set price). When units are dispatched out-of-merit, RSG costs generally increase. In addition, peaking resources, because they can start relatively quickly, are often the only resources that can be committed in real time to serve load not scheduled day-ahead. Hence, if real-time prices are not set by the committed peaking resources, real-time prices will be lower and will not reveal the natural incentive to schedule load fully in the day-ahead market—fully-scheduled load in the day-ahead market would allow lower-cost resources to be committed in place of the peaking resources.

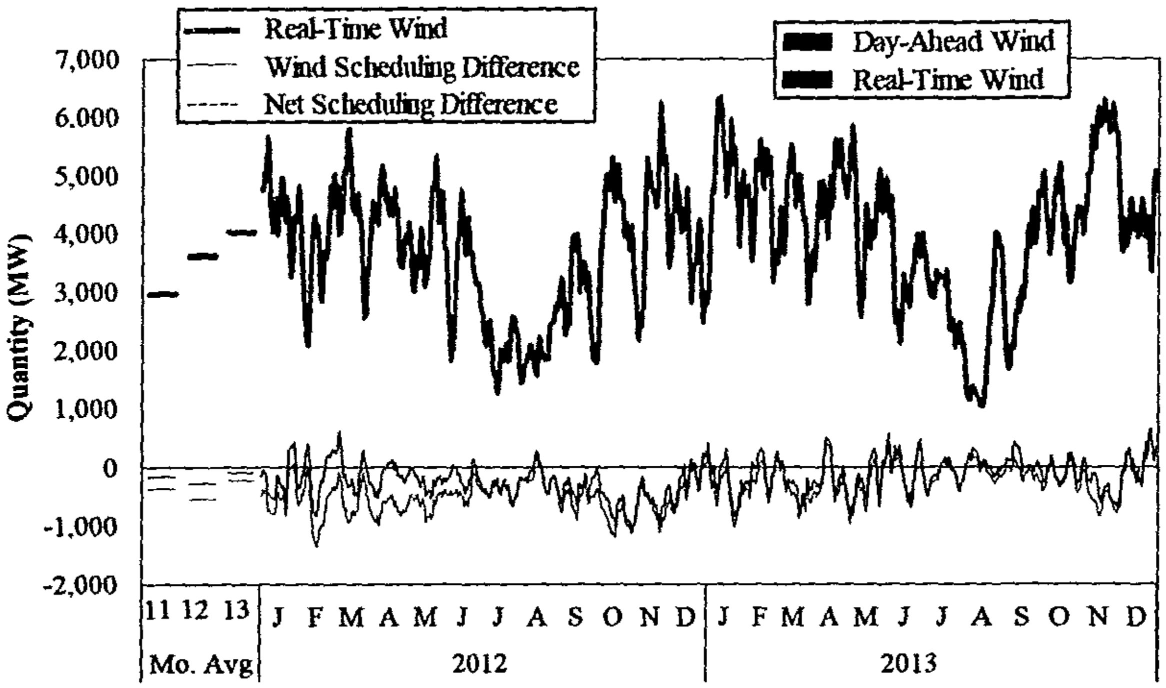
In addition, setting inefficiently-low real-time prices can encourage participants to import and export power inefficiently. MISO's new "Extended LMP" pricing method, expected to be implemented October 2014, should allow peaking resources to set prices more often when they are needed to satisfy the system's energy and ASM requirements. This should improve MISO's real-time energy pricing, reduce RSG payments, and improve the results of the day-ahead market.

E. Wind Generation

Wind generation in MISO has grown steadily since the start of the markets in 2005 and exceeded 12 GW of installed capacity in 2013. Although wind generation promises substantial environmental benefit, the output of these resources is intermittent. As such, wind generation presents particular operational, forecasting, and scheduling challenges. These challenges are amplified as wind's portion of total generation increases. Wind resources accounted for over 9.3 percent of installed capacity and 7.4 percent of generation in 2013.

Figure 20 shows a seven-day moving average of day-ahead scheduled wind and real-time wind output since 2012.

Figure 20: Day-Ahead and Real-Time Wind Generation
2012–2013



Real-time wind generation in MISO increased 11 percent in 2013 to an average of 4,028 MW per hour. The figure also shows that wind output is substantially lower during summer months than during shoulder months, particularly during the highest load hours. This reduces its value from a reliability perspective. Day-ahead scheduling increased in 2013. Under-scheduling of wind output in the day-ahead market can create price convergence issues and lead to uncertainty regarding the need to commit resources for reliability. The figure shows virtual supply (net of virtual demand) at wind locations substantially offset the impact of under-scheduling by wind resources, making up more than one-half of the deficit.

Managing wind output is significantly aided by the adoption of the Dispatchable Intermittent Resource (DIR) type, which was first introduced in June 2011.[19] DIR participation by wind resources provides MISO much more timely control over its wind resources by allowing them to be dispatchable (i.e., to respond economically to dispatch instructions). The expansion of DIR has almost entirely eliminated manual curtailments as a means to manage congestion caused by wind output or to manage over-generation conditions. Economic curtailments in 2013 averaged 140 MW per interval and at times exceeded 1 GW, compared to just 8 MW of manual wind curtailments. Wind resources that are DIRs can set prices—they did so in nearly one-half of all intervals—at an average of -$11 per MWh. These low prices set by wind resources typical prevail in relatively small congested areas.

Finally, as total wind capacity continues to grow, the volatility of its output that must be managed by MISO also grows. Volatility of wind output, as measured by the absolute average interval change in output between intervals and excluding economic DIR curtailments, rose to 291 MW per hour and frequently exceeded 500 MW in the downward direction. Significant reductions in output, when they are not forecasted, can lead to substantial price volatility and can require MISO to make real-time commitments to replace the lost output. The DIR has been valuable in improving the control of wind resources and responding to these changes in output. In addition, recommendations for managing the system's ramp capability that are included in this report should further improve MISO's ability to respond efficiently and reliably to fluctuations in wind output.

19 As of the March 2014 commercial model, 118 out of 183 wind units (approximately 80 percent of capacity) are modeled as DIR. Most other wind resources are exempt from the DIR requirement.

VI. Transmission Congestion and Financial Transmission Rights

MISO manages flows over its network to avoid overloading transmission constraints by altering the dispatch of its resources to establish efficient, location-specific prices that represent the marginal costs of serving load at each location. Transmission congestion arises when the lowest-cost resources cannot be fully dispatched because transmission capability is limited. As a result, LMPs can vary substantially across the system, reflecting the fact that higher-cost units must be dispatched in place of lower-cost units to serve incremental load in order to avoid overloading transmission facilities. This causes LMPs to be higher in "constrained" locations.

LMPs also include a marginal loss component. Transmission losses occur whenever power flows across the transmission network. Generally, transmission losses increase as power is transferred over longer distances, at higher volumes, and over lower-voltage facilities.

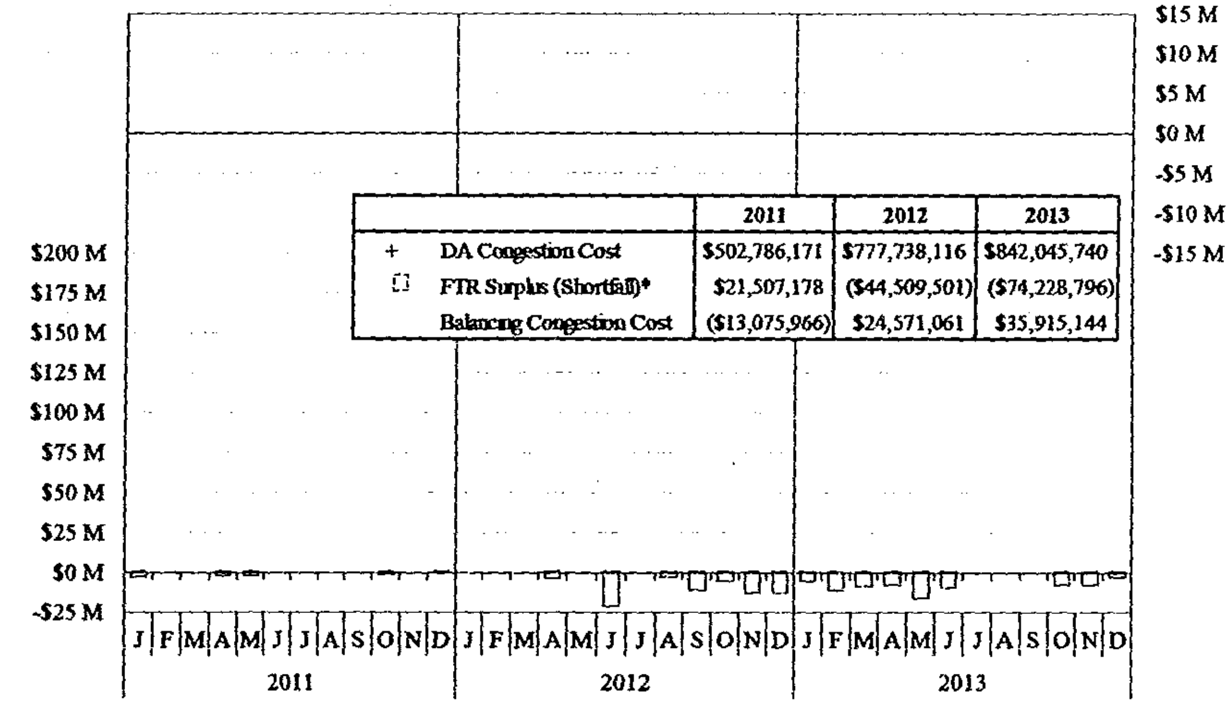
A. Day-Ahead Congestion Costs and FTRs

MISO's day-ahead energy market is designed to send accurate and transparent locational price signals that reflect congestion and losses on the network. MISO collects congestion revenue in the day-ahead market based on the differences in the LMPs at locations where energy is scheduled to be supplied and where it is scheduled to be consumed.

The resulting congestion revenue is paid to holders of FTRs, which represent the economic property rights associated with the transmission system. A large share of the value of these rights is allocated to participants. The residual FTR capability is sold in the FTR markets with this revenue contributing to the recovery of the costs of the network. FTRs provide an opportunity for market participants to hedge against day-ahead congestion. As such, congestion costs and FTR obligations should be roughly equal unless the transmission capability reflected in participants' FTRs is more or less than the transmission capability available to the day-ahead market.

Figure 21 summarizes the day-ahead congestion, the obligations to FTR holders and surpluses/shortfalls, as well as balancing congestion on a monthly basis from 2011 to 2013.

Figure 21: Day-Ahead Congestion and Payments to FTRs
2011–2013



Note: * Excludes contributions of monthly auction residual collections which totaled $4.36 million in 2013.

Day-ahead congestion costs rose 8.3 percent to total $842 million in 2013. The increase in day-ahead congestion coincided with increases in fuel prices that generally increase the cost of redispatching generation to manage network power flows. Much of the increase occurred on internal constraints in the West Region, many of which are affected by the increasing output from wind resources. MISO has continued to enhance its day-ahead processes to fully model potential transmission constraints in the day-ahead market.

FTR obligations exceeded congestion revenues by over 8 percent, most of which occurred in the first half of the calendar year (the prior FTR year). These FTR funding shortfalls occurred mostly on internal constraints. The largest single cause for underfunding continued to be outages that were not modeled in the 2012–2013 annual FTR auction. While the majority of the outage-related underfunding was due to forced outages, a significant amount was related to planned outages that were not provided to MISO in time for inclusion in the auction. MISO has worked to improve the convergence of the FTR modeled transmission capability and the transmission capability available in the day-ahead market. As a result, FTR funding improved at the beginning of the 2013-2014 FTR year, averaging less than 2.5 percent after May.

Other contributors to FTR underfunding included underestimated loop flow and firm-flow entitlements. Therefore, because MISO collects day-ahead congestion revenues for only the portion of transmission capability that is available to the day-ahead market, it sells or allocates FTRs for only that portion. As a result, aligning the available transmission capability in the FTR and day-ahead markets ensures that FTR shortfalls and surpluses are limited.

As a share of total dollars, FTRs in 2013 received just 84 percent of the day-ahead congestion revenue, down from 89 percent in 2012 and 91 percent in 2011. Other forms of transmission rights, such as "carve-outs" and "Option B" FTRs, accounted for over $87 million in payments. These rights were established at the start of the markets to account for grandfathered transmission agreements. The majority of these exist in the West region, so payments to these holders—over $47 million went to one participant—have risen in recent years along with the increase in congestion and DIR adoption in that region. It is important that a high percentage of day-ahead congestion continues to be paid to FTRs because the other transmission rights do not provide the same efficient incentives as FTRs.

Finally, MISO implemented two significant changes to the FTR markets in 2013:

- In March, MISO eliminated the ability of participants to purchase same-bus "zero-cost" FTRs that can lead to underfunding under certain conditions.
- In the fall, MISO began operating the Multi-Period Monthly Auction or (MPMA), which permits Market Participants to purchase (or sell) FTRs for the next month and several future months in the current planning year. This should improve participants' ability to manage congestion risk.

B. Balancing Congestion Shortfalls

Balancing congestion shortfalls in 2013, which are shown in the top panel of Figure 21, were a small share of total congestion costs. These costs generally occur when the transmission capability available in the real-time market is less than what was scheduled by the day-ahead market. Balancing congestion shortfalls can result from forced transmission outages or derates in real time, or greater than anticipated loop flows. In 2013, balancing congestion shortfalls totaled $52.6 million, indicating that the real-time binding constraint flows were slightly less than the amount cleared in the day-ahead market.

C. Real-Time Congestion Value

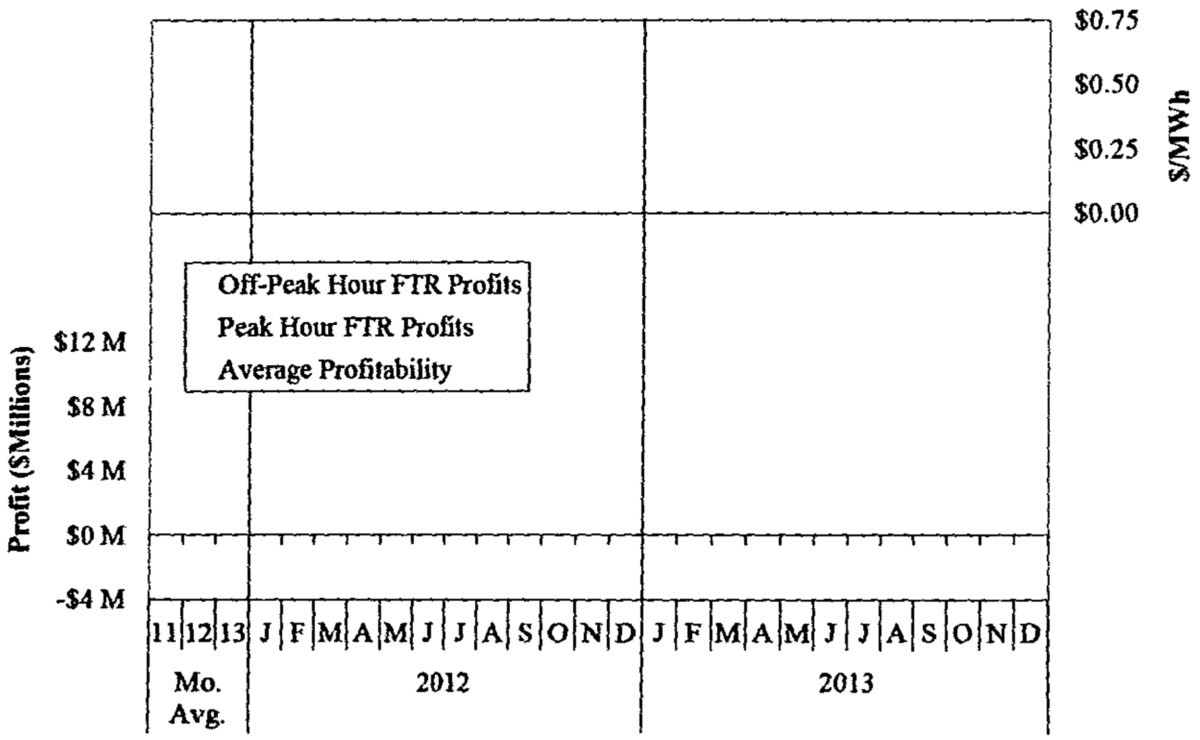
Congestion revenues collected through the MISO markets are substantially less than the value of real-time congestion on the system, which totaled $1.59 billion in 2013. This substantial difference is caused primarily by loop flows that do not pay MISO for use of its network and PJM's entitlements on the MISO system (PJM does not pay for its use up to its entitlement).

The total real-time congestion value increased 22.1 percent from 2012, the vast majority of which occurred on internal (including MISO-managed market-to-market) constraints. It was greatest in the fourth quarter because of significant outages in the West region. Increased fuel prices also contributed to the higher congestion value in 2013.

D. FTR Market Performance

FTR price convergence with anticipated day-ahead congestion is an indicator of the performance of the FTR market. Good price convergence occurs when there are low FTR profits or losses, which are the difference between the price of the FTR and the congestion paid to it. In Figure 22, we show the profitability of FTRs sold in the monthly market.

Figure 22: Monthly FTR Profitability
2012–2013



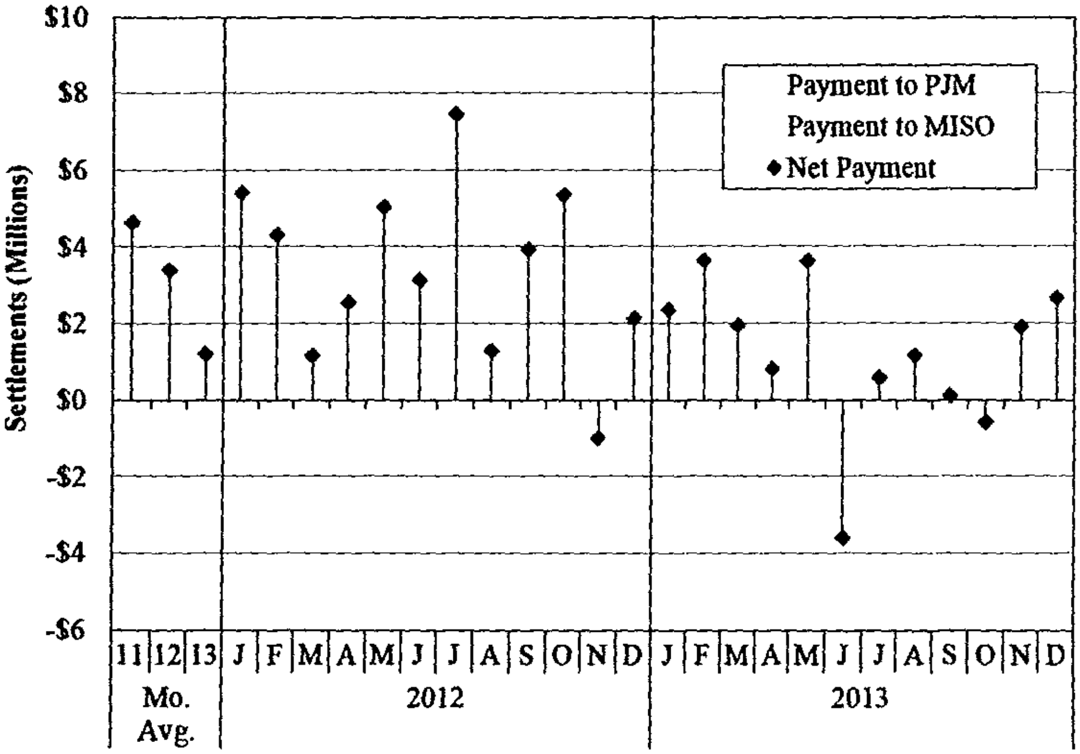
Incremental capability sold in the monthly auctions was more profitable (at $0.22 per MWh), but did not track changes in congestion as well as it has in prior years. The general prevailing pattern of west-to-east congestion was not as significant in 2013 as it was in previous years. This likely resulted in the FTR market overestimating the congestion out of the West region.

In 2013, the profitability of seasonal FTRs sold in the annual auction (not shown) averaged $0.07 per MWh, down from $0.20 last year, and was greatest in the spring and fall. In general, this indicates that the FTR markets produced prices that reasonably reflected anticipated congestion.

E. Market-to-Market Coordination with PJM

MISO's market-to-market (M2M) process under the Joint Operating Agreement (JOA) with PJM efficiently manages constraints affected by both RTOs. The process allows each RTO to utilize re-dispatch from the other RTO's resources to manage its congestion if it is less costly than its own relief. Each RTO is compensated for excess flows from the other RTO when those flows exceed their Firm Flow Entitlement (FFE). Much of the M2M process is now automated and has improved pricing in both markets. Figure 23 shows settlement results for 2012 and 2013.

Figure 23: Market-to-Market Settlements
2012–2013



Congestion on MISO M2M constraints declined 10 percent from last year to $291.5 million, while on PJM M2M constraints it remained relatively low at $15.8 million.[20] Figure 23 shows net payments flowed from PJM to MISO in most months in 2013 because PJM exceeded its FFE on MISO's system much more frequently than MISO did on PJM's system. Net payments by PJM to MISO declined 72 percent from 2012. PJM payments of $32.2 million were offset by $14.7 million in payments by MISO, mostly in June.

An error in the PJM FFE calculation that began in late October 2012 was discovered and corrected in mid-February 2013. The error overstated PJM's entitlement on several constraints in late 2012 and 2013, and resulted in a $4.28 million settlement (approximately $2 million of this occurred in 2013).

Shadow price convergence on MISO M2M constraints, an indicator of PJM's responsiveness to requests for relief, was reasonable in 2013 and was comparable to convergence on PJM M2M constraints. Nonetheless, the RTOs should continue to identify enhancements to the relief software, modeling parameters, or other procedures that may be limiting the provision of relief.

We recommended in our *2012 State of the Market Report* that both RTOs incorporate the coordinated use of FFEs into the day-ahead market, which should improve the efficiency of both RTOs' markets. The RTOs have made considerable progress in developing a conceptual framework for coordination, and a final design is expected in late 2014 with possible implementation in late 2015.

F. Congestion on Other External Constraints

Congestion in MISO can occur when other system operators call for Transmission Line-Loading Relief (TLRs), which causes MISO to activate the external constraint in its real-time market. This results in MISO's LMPs reflecting the marginal cost of providing the requested relief and associated congestion costs being collected from MISO's customers.

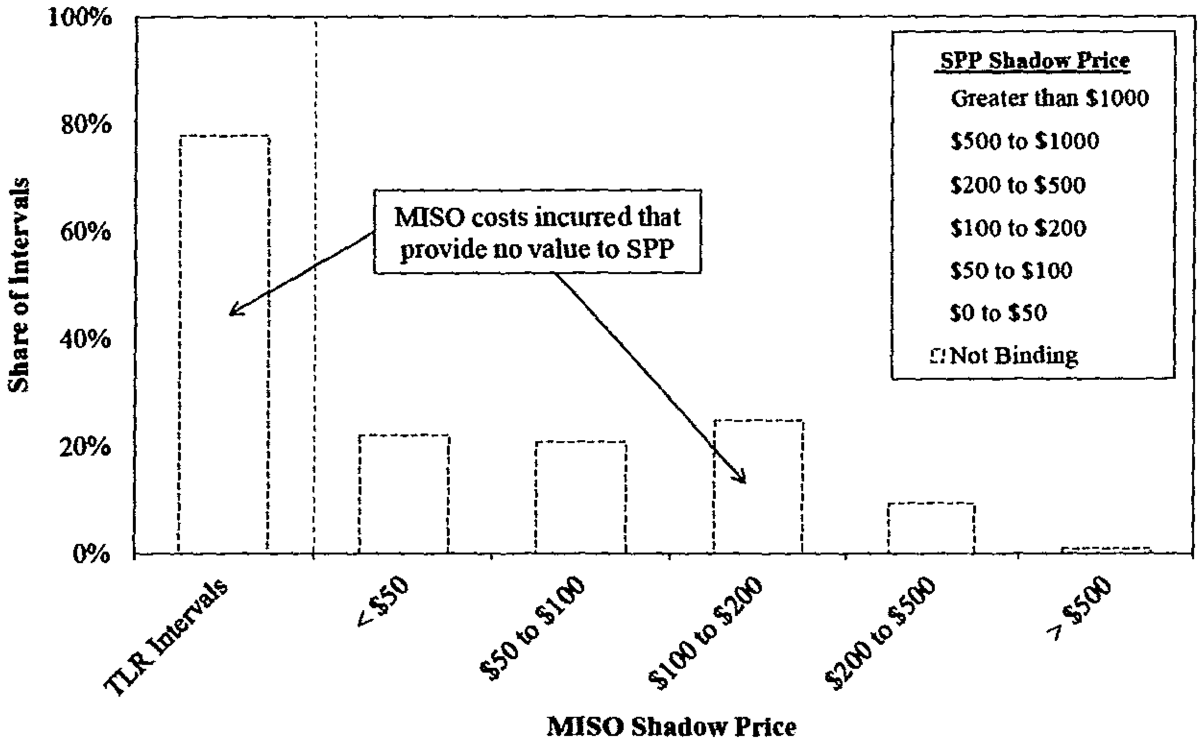
20 As mentioned in the previous subsection, even though the congestion value is relatively small on external flowgates, their price impacts can be substantial.

The congestion value on external flowgates corresponded to a small share of total congestion in 2013, but had widespread price impacts. In fact, the transmission constraint that had the largest impact on generator LMPs in 2012 was an external constraint managed by SPP (Iatan-Stranger).

One reason this flowgate and other external non-market-to-market flowgates often have a large impact on the MISO market is that MISO receives relief obligations based on forward direction flows, even if on net (when reverse-direction flows are included) its market flows are relieving the constraint. MISO reports its Market Flow to the IDC in the net, forward-only, and reverse-only directions. The forward-only flows alone are used to determine the relief obligation when an external (non-M2M) flowgate binds and a TLR is called.

To evaluate the efficiency of this process, we compare MISO's shadow prices (the marginal cost of the relief provided by MISO) to SPP's shadow prices on the TLR constraints (the marginal value of the relief provided by MISO). This comparison is shown in Figure 24 for March of 2014, a period following the launch of SPP's new market for which we have SPP constraint data.

Figure 24: MISO vs SPP Shadow Prices on SPP TLR Constraints
March 2014



The figure reveals the gross inefficiency of this process—in 78 percent of the intervals when the TLR constraints are generating congestion costs in MISO, the constraint is not binding in SPP and the relief has no marginal value. On average, MISO's shadow prices are almost four times larger than SPP's shadow prices. These inefficient costs incurred by MISO translate to higher costs for many MISO customers in the form of higher LMPs at many locations paid by loads, lower LMPs paid to generators at many locations and inefficient payments to external transactions that are generally recovered from MISO's customers through an uplift charge. In total, we estimated that these three categories of costs totaled $192 million and $113 million in 2012 and 2013, respectively.

These results highlight the importance of our recommendations to revisit these coordination procedures to quantify MISO's relief obligations and the importance of using MISO's Transmission Constraint Demand Curve for TLR constraints to reduce these inefficiencies.

VII. External Transactions

A. Overall Import and Export Patterns

As in prior years, MISO in 2013 remained a substantial net importer of power in both the day-ahead and real-time markets. Real-time net imports decreased 7 percent to an average of 3.7 GW per hour. Imports from PJM declined 24 percent to 1.7 GW on average, while those from Manitoba and Ontario both rose nearly 30 percent (and even more during off-peak hours). Approximately one-third of interchange was associated with wheels through MISO (see next section), including 95 percent of imports from Ontario and 87 percent of exports to PJM. A substantial share of this activity is likely attributable to the interface pricing issues discussed later in this section.

Price differences between MISO and adjacent areas create incentives to schedule imports and exports that change the net interchange between the areas. These interchange adjustments are essential from both an economic and reliability standpoint. Scheduling that is responsive to the interregional price differences captures substantial savings as lower cost resources in one area displace higher-cost resources in the other area. However, participants' ability to capture these benefits by effectively arbitraging interregional price differences is undermined by the fact that participants must schedule in advance and, therefore, must forecast the prevailing price differences.[21] Additionally, the lack of RTO coordination of participants leads to substantial errors in the aggregate quantities of interregional transaction changes.

To evaluate the efficiency of interregional scheduling, we track the share of the transactions that were profitable (i.e., scheduled from the lower-priced market to the higher-priced market), which lowers the total production costs in both regions. The share of transactions with PJM that were scheduled in the profitable direction was 52 percent, a slight improvement from recent years. Many hours still exhibit large price differences that can be attributed to scheduling uncertainties. Additionally, the uncoordinated transaction scheduling process led to shortages that impaired reliability and to unnecessary price volatility.

21 The scheduling notification deadline was reduced to 20 minutes in October 2013 in compliance with FERC Order 764.

To address these issues, we continue to recommend that MISO expand the JOA with PJM to optimize the interchange and improve the interregional price convergence. We have previously estimated the benefits of optimizing the interchange between PJM and MISO, and between the other RTOs around Lake Erie, and found substantial available efficiency benefits. In total, we found production cost savings of $309 million per year, of which $59 million was attributable to optimizing the interchange between PJM and MISO. We believe these values understate the true cost savings because the study was conducted during a period of lower load and fuel prices, which decrease the economic savings of optimizing the interchange.

One means to capture these benefits is to allow participants to submit offers to transact within the hour if the spread in the RTOs' real-time prices is greater than the offer price. This is generally referred to as Coordinated Transaction Scheduling (CTS). In addition to the economic benefits, this would improve reliability by preventing operating reserve shortages that sometimes occur under the current scheduling rules. PJM is implementing this type of approach with New York ISO in November 2014, and has indicated they are supportive of implementing a similar approach with MISO after this is complete.

B. Loop Flows Around Lake Erie

Transactions scheduled between RTOs are settled on a "contract path" basis, while power actually flows according to the physical properties of electricity. This difference, known as loop flow, is particularly significant when transactions are scheduled around Lake Erie. Operators must account for these loop flows in the real-time, day-ahead, and FTR markets.

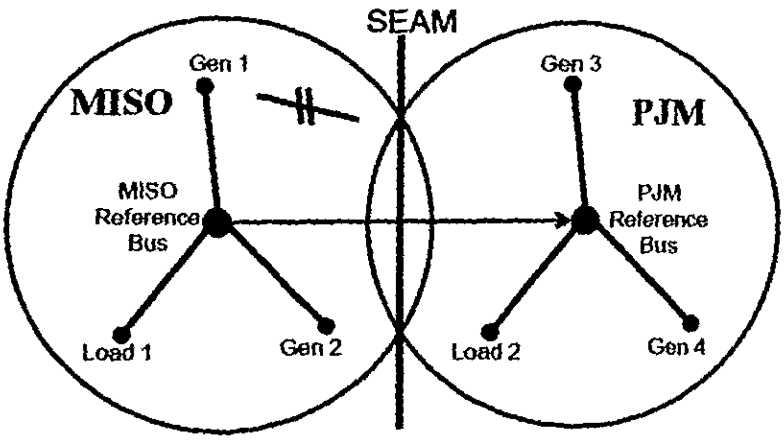
To better manage loop flows around Lake Erie, MISO and IESO installed Phase Angle Regulators (PARs) that began full operation in July 2012. Both the PARs and changes in transaction patterns contributed to a substantial decrease in clockwise loop flows from 2011 to 2013. For the year, average hourly Lake Erie loop flows were 3 MW in the counter-clockwise direction in 2013, whereas it was 155 MW in the clockwise direction in 2011. Average hourly clockwise loop flows exceeded 400 MW in only 3 percent of hours, down from 16 percent in 2011. These reductions have reduced the need of other RTOs around Lake Erie to call TLRs, which has benefitted MISO by lowering MISO's balancing congestion costs (negative ECF).

C. Interface Pricing and External Transactions

Interface prices are used to settle with participants that schedule physical schedules into, out of, or through MISO over a particular interface. These prices are critical because they establish the incentives that will govern participants' external transaction schedules.

All of the locational congestion effects in the interface prices are measured against a central "reference bus". The LMP at each location includes: (a) the system marginal price, (b) the congestion component, and (c) the marginal loss component. To calculate the congestion component of the interface price for a constraint, the RTO first calculates the marginal flow impact on the constraint (i.e., the "shift factor") of injecting a megawatt at the MISO reference bus and withdrawing it at specified locations (known as the "interface definition") in the adjacent area. This is depicted in the following illustration for MISO and PJM.

The congestion component is equal to this marginal flow impact multiplied by the shadow price for the internal constraint. In this way, the effects on the constraint of transferring power to or from an adjacent area are reflected in the congestion component of the interface price.



1. Interface Pricing with PJM

By establishing an interface price that includes the congestion effects of a transfer between MISO and PJM, the congestion benefits or costs will be fully priced and settled. This is essential because it provides efficient incentives for participants to schedule transactions between the two areas. As described below, however, the interface prices set by the RTOs do not currently provide efficient incentives to schedule external transactions when market-to-market constraints are binding or when TLR constraints are binding because of a flaw that we first identified in mid-2012.

The flaw is that *both* MISO and PJM are independently estimating the full marginal effects of external transactions scheduled between the areas on all binding constraints. As a result, both RTOs interface prices will include congestion components that reflect the congestion effects on the same constraint, resulting in duplicative settlements. For example, if MISO estimates a shift factor on a constraint for an export to be -10 percent (e.g., it provides relief) and the constraint has a shadow cost of $500 per MWh, MISO congestion component for the PJM interface will be -$50 per MW. This will encourage the export. If PJM estimates the same shift factor and has the same shadow cost for the MISO market-to-market constraint, it will also calculate a congestion component for the MISO interface of $50. This will cause the participant to receive a congestion payment of $100 per MWh to schedule this transaction even though it is only providing relief on the constraint worth $50 per MWh.

In the *2012 State of the Market Report*, we provided specific examples of the problem, which are reproduced in the Appendix of this report in Section VI.B.2. To establish empirically the double settlement, we identified hours when no constraints were binding in PJM or MISO except a single common market-to-market constraint. Hence, in these examples, the congestion component of the interface prices in both PJM and MISO will solely reflect the effects of the single binding market-to-market constraint. Indeed, we found the prices on both sides of the interfaces reflected the similar congestion.

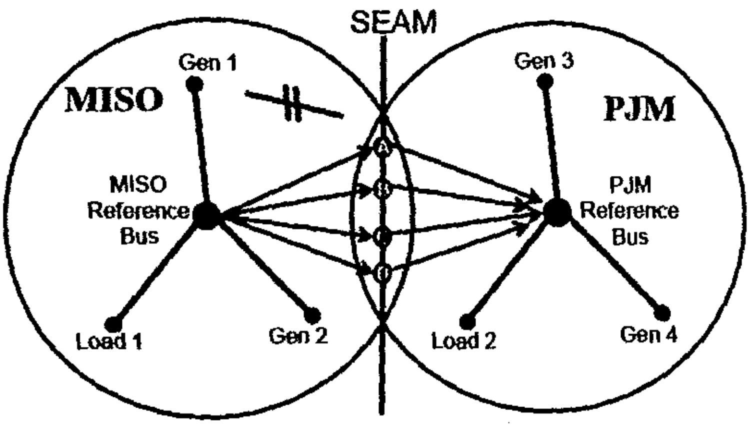
We also quantified some of the related inefficiencies and costs to both PJM and MISO related to this pricing flaw. We estimate that PJM made $16.5 million in net over-payments on market-to-market constraints in 2013, down from $29.4 million in 2012. These overpayments have grown in the first quarter of 2014 to $18.5 million. These amounts do not include overpayments made for other external constraints. In addition to the overpayments for transactions that are expected to help relieve the constraint, this issue causes transactions to be overcharged for congestion when they are expected to aggravate a constraint. Although this effect will not result in uplift, it serves as an economic barrier to efficient external transactions.

Throughout 2013 and into 2014, we have been working with MISO and PJM, and their respective stakeholders through the JCM process to explain the problem and our proposed solution. We have now largely achieved a consensus between the RTOs on the problem and continue to discuss potential solutions.

To eliminate the redundant market-to-market congestion pricing, the interface definitions and pricing must be modified to settle only once the effects of transferring power from one area to the other area. One way to do this is to simply have the monitoring RTO alone price the congestion on its own market-to-market constraints. This is consistent with the simple example initially discussed in this section, in which MISO estimates the effect of the export on its constraint and fully prices that effect in its interface price so there is no need for PJM to price it. Because this solution is simple and would ensure efficient pricing on all market-to-market and other transmission constraints, we have recommended that both RTO's adopt this approach.

PJM's current preferred approach for addressing the duplicative congestion pricing for market-to-market constraints is to change the definition of the interface with MISO. Instead of assuming the power is sourcing or sinking inside the neighboring area, PJM has proposed for MISO and PJM to both define their interfaces based on a common set of points at the seam as illustrated in the following diagram.

Utilizing a common interface definition eliminates the redundant congestion pricing because the RTOs would each estimate only part of the flow effects of the transaction. Under this proposal, MISO would price the congestion effects ***from*** its Reference Bus to A, B, C, and D, while PJM prices the same effects from the seam ***to*** its Reference Bus.



While this may have intuitive appeal, this solution will produce an efficient settlement only if:

- the MISO shift factor plus PJM's shift factor equal the shift factor that MISO would have calculated under our proposed approach for the entire path; and

- both RTO's real-time markets produce similar shadow prices for the constraint.

We have evaluated this solution and found that these two necessary conditions do not always hold, and that the total settlement will therefore be distorted. We find that the PJM proposal inflates the shift factors for many constraints because the seam locations are electrically closer to many of the constraints. The shift factors can still sum to the correct total because they tend to have opposite signs, so they will generally offset one another.

However, there are three problems with relying on this offsetting change:

- The RTO that overpays due to the inflated shift factors would generate balancing congestion or FTR underfunding. There is no settlement mechanism for the RTO that is benefiting from the inflated shift factors to provide a reimbursement.
- The non-monitoring RTO's shadow price (PJM's in this example) is often lower than the monitoring RTO's shadow price. When that happens, the settlement will not be efficient because the non-monitoring RTO's congestion component will not offset the inflated congestion component of the monitoring RTO.
- If the constraint is a not a market-to-market constraint, there will be no offsetting settlement by the non-monitoring RTO, so the inflated shift factor will simply provide an inefficient incentive to schedule transactions and generate balancing congestion or FTR underfunding.

We do not believe these problems can be effectively addressed under the PJM proposal and have yet to identify any potential issues or inefficiencies with our proposal. Therefore, we continue recommend that both PJM and MISO implement the approach we have developed.

2. Interface Pricing and Other External Constraints

Market-to-market constraints activated by PJM are one type of external constraint that MISO activates in its real-time market. MISO also activates constraints located in external areas when the external system operator calls a TLR and redispatches its generation to meet its flow obligation.

It is appropriate for external constraints to be reflected in MISO's real-time dispatch and internal LMPs because this enables MISO to respond to TLR relief requests as efficiently as possible. While redispatching internal generation is required, MISO is not obligated to pay participants to schedule transactions that relieve constraints in external areas. In fact, the effects of real-time physical schedules are excluded from MISO's market flow, so MISO gets no credit for any relief that its external transactions may provide. Because MISO receives no credit for this relief and no reimbursements for the costs it incurs, it is inequitable for MISO's customers to bear these costs. These costs totaled $3.9 million in 2013 and $2.1 million in 2012.

In addition to the inequity of these congestion payments, they motivate participants to schedule transactions inefficiently for two reasons. In most cases, beneficial transactions are already being fully compensated by the area in which the constraint is located. For example, when an SPP constraint binds and SPP calls a TLR, it will establish an interface price for MISO that includes the marginal effect of the transaction on its own constraint. Hence, MISO's additional payment is duplicative and inefficient.

Second, MISO's shadow cost for external TLR constraints is generally overstated relative to the true marginal cost of managing the congestion on the constraint. For example, we show in Section VI.F that MISO's shadow prices on SPP's constraints are on average almost four times larger than SPP's shadow prices. This causes the congestion component associated with TLR constraints that is included in the interface prices to be highly distortionary and provide inefficient scheduling incentives. One should expect that this will result in inefficient schedules and higher costs for MISO customers. Therefore, we continue to recommend that MISO take the necessary steps to remove all external congestion from its interface prices.

VIII. Competitive Assessment and Market Power Mitigation

This section contains a competitive assessment of the MISO markets. Locational market power in wholesale markets can be substantial when transmission constraints or reliability requirements limit the effective competition to satisfy the system's needs in an area. This section includes a review of market power indicators, an evaluation of participant conduct, and a summary of the use of market power mitigation measures in 2013.

A. Structural Market Power Analyses

We analyze market concentration as measured with the Herfindahl-Hirschman index (HHI). Market concentration is low for the overall MISO area, but the East Region and WUMS Area is highly concentrated. The regional HHIs are higher than those in the comparable zones of other RTOs because vertically-integrated utilities in MISO that have not divested generation tend to have substantial market shares. However, since the metric does not recognize the physical characteristics of electricity or network constraints, the HHI is limited as an indicator of overall competitiveness.

A more reliable indicator of potential market power is whether a supplier is pivotal, which occurs when its resources are necessary to satisfy load or to manage a constraint. Our regional pivotal supplier analysis indicates that the frequency with which a supplier is pivotal rises sharply with load. This is typical in electricity markets since electricity cannot be economically stored. Hence, when load increases, the excess capacity will fall and the resources of large suppliers will become more necessary.

We also evaluate local market power by identifying pivotal suppliers for relieving transmission constraints. We focus the analysis on two types of constrained areas that are currently defined for purposes of market power mitigation: Narrow Constrained Areas (NCAs) and Broad Constrained Areas (BCAs). NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed). Five NCAs are currently defined: Minnesota, WUMS, and North WUMS (a subarea of WUMS) in the Midwest Region, and the Amite South and WOTAB NCAs in the South

Region.[22] BCAs include all other areas within MISO that are isolated by transient binding transmission constraints.

The vast majority (88 percent) of binding BCA constraints in 2013 had at least one supplier that was pivotal. In nearly 95 percent of intervals, at least one BCA constraint with a pivotal supplier was binding. NCA constraints into WUMS were similarly pivotal, while those into Minnesota were pivotal approximately 60 percent of the time. Fewer constraints make up an NCA, however, so the share of intervals with a pivotal supplier in these NCA regions was far lower. Overall, these results indicate that local market power persists with respect to both BCA and NCA constraints, and that market power mitigation measures remain critical.

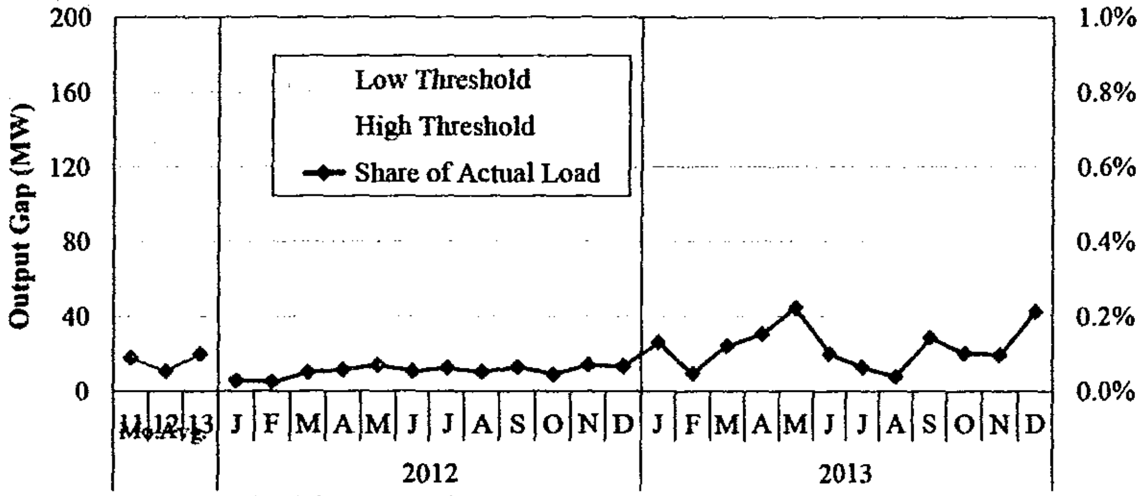
B. Evaluation of Competitive Conduct

Despite these indicators of structural market power, our analyses of individual participant conduct show little evidence of attempts to physically or economically withhold resources to exercise market power. This is confirmed in aggregate metrics of market competitiveness. We calculated a price-cost mark-up that compares the system marginal price based on actual offers to a simulated SMP that assumes all suppliers had submitted offers at their estimated marginal cost. We found an average system marginal price mark-up of just 1.7 percent, which reflects the competitiveness of MISO's energy markets.

The next figure shows the "output gap" metric, which we use to detect instances of potential economic withholding. The output gap is the quantity of power not produced from resources whose operating costs are lower than the LMP by more than a threshold amount. We perform the output gap analysis using the Tariff's conduct threshold for mitigation (the "high threshold") and a "low threshold" equal to one-half of the mitigation threshold. The figure shows that output gap levels continued to be very low in 2013. At the low threshold, it averaged only 73 MW at the low threshold and 24 MW at the high (mitigation) threshold. These levels are slightly higher than in 2012, mainly because the NCA threshold for the Minnesota NCA declined from $64.10 per MWh in 2012 to $23.17 in 2013.

22 Since the South Region did not join MISO until late December, 2013, we exclude these two NCAs in our evaluations.

Figure 25: Economic Withholding – Output Gap Analysis
2012–2013



	Mo. Avg. 11	Mo. Avg. 12	Mo. Avg. 13	2012 J	F	M	A	M	J	J	A	S	O	N	D	2013 J	F	M	A	M	J	J	A	S	O	N	D
Low Threshold Results by Unit Status (MW)																											
Offline	24	4	13	4	4	1	1	9	0	11	0	8	0	2	5	8	2	6	0	12	2	9	0	26	11	4	70
Online	34	26	56	12	9	24	27	29	32	33	31	26	23	36	32	69	25	62	79	104	56	30	22	55	42	50	74
High Threshold Results by Unit Status (MW)																											
Offline	22	3	10	4	4	1	1	9	0	9	0	5	0	1	4	7	1	4	0	10	1	6	0	23	7	2	59
Online	8	5	14	2	1	2	4	6	7	7	7	5	3	9	11	27	4	11	20	22	15	5	5	14	11	11	20

These levels are extremely low, averaging approximately 0.1 percent of load, and raise no competitive concerns. Nonetheless, we monitor these levels on an hourly basis and routinely investigate instances of potential withholding.

C. Summary of Market Power Mitigation

Most market power mitigation in MISO's energy market continues to occur pursuant to automated conduct and impact tests that utilize clearly-specified criteria. The mitigation measure for economic withholding caps a unit's offer price when it exceeds the conduct threshold and the offer raises clearing prices or RSG payments substantially. Because conduct has generally been competitive, market power mitigation has been imposed infrequently.

The mitigation thresholds differ depending on the two types of constrained areas that may be subject to mitigation: BCAs and NCAs. The market power concerns associated with NCAs are higher because they are chronic. As a result, conduct and impact thresholds for NCAs can be substantially lower than they are for BCAs (they depend on the frequency with which NCA constraints bind). The lower mitigation thresholds in the NCAs generally lead to more frequent mitigation there than in BCAs, even though the system has many more BCAs.

Very little energy mitigation was imposed in the day-ahead market. This is expected because the day-ahead market is much less vulnerable to withholding because of the liquidity provided by virtual traders and flexibility MISO has to commit resources. Real-time NCA and BCA energy mitigation rose from 2012, but remained infrequent. Despite infrequent mitigation in 2013, the pivotal supplier analyses discussed earlier in this section continue to indicate that local market power is a significant concern. Hence, market power mitigation measures remain essential.

D. Evaluation of RSG Conduct and Mitigation Rules

Local market power can also be associated with reliability needs that cause resources to be committed by MISO. This form of market power would be exercised by changing a resource's offer parameters to increase the RSG payment received by the supplier. To evaluate how effective the mitigation measures have been in addressing this form of market power, we determined the portion of the RSG paid that corresponds to competitive offers. This analysis indicates that only approximately one-half of the RSG cost is associated with competitive offer prices, while the other half is attributable to increases in one or more offer parameters above competitive levels. In early 2014, RSG costs rose sharply and much of the increase was associated with offers in excess of competitive levels.

The MISO market has two approaches for testing and mitigating market power exercised to increase RSG payments, one that was developed before the start of the market for congestion-related commitments and one that was developed recently to mitigate VLR commitments. We compare the two frameworks in this section. The key differences in these frameworks include:

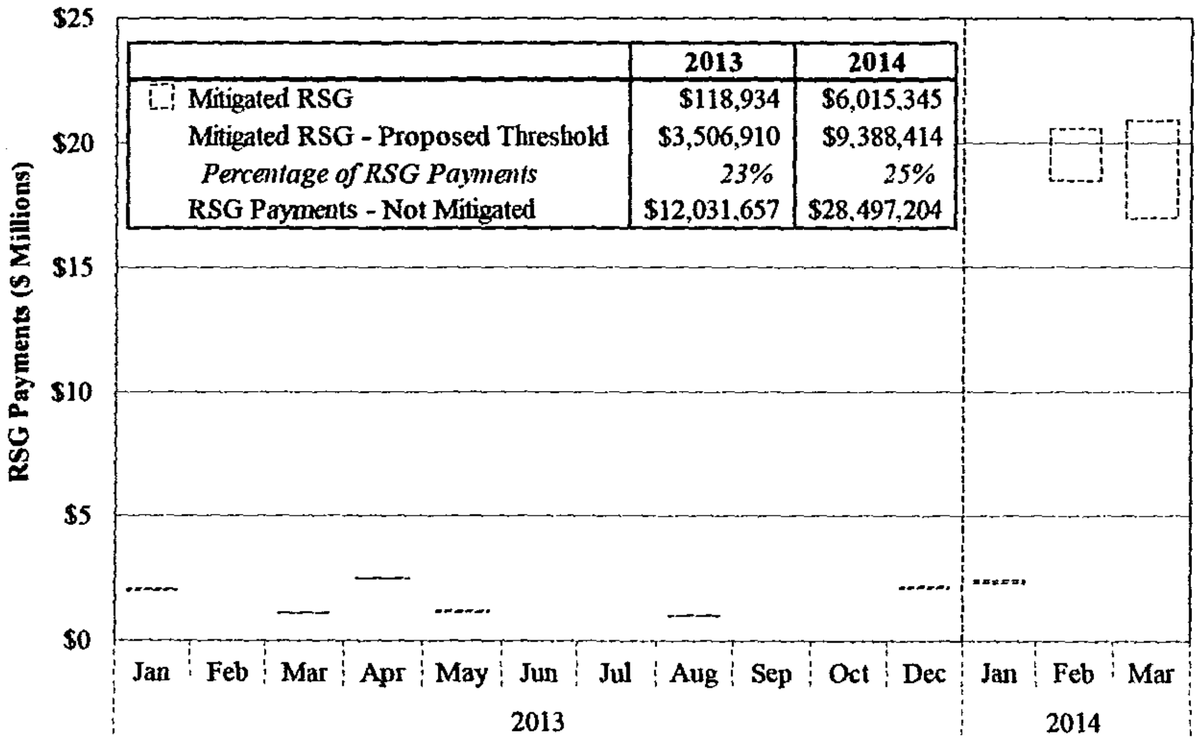
- Congestion-related mitigation measures call for conduct tests to be performed on each offer parameter individually and include an impact test with a $50-per-MW threshold to determine when conduct identified through the conduct test should be mitigated.

- VLR mitigation measures utilize a conduct test based on the aggregate as-offered production cost of a resource (recognizing the joint effect of all of the offer parameters). The VLR production cost-based conduct test effectively serves as an impact test as well. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG.

Our evaluation of the VLR mitigation framework suggests that it is more effective at addressing market power exercised to increase RSG payments, in part because measuring the joint effect of all offer parameters is a superior approach for identifying anticompetitive conduct. We studied whether applying the VLR RSG mitigation framework to all RSG would be more effective than the current RSG mitigation rules. Because market power concerns associated with the VLR commitments are much greater, it is reasonable to employ a tighter threshold for VLR mitigation than for other RSG mitigation. Therefore, we evaluated a conduct and impact threshold equal to the greater of $25 per MWh or 25 percent (rather than the 10 percent threshold applied to VLR commitments). This threshold should balance the need for suppliers to modify their offers to reflect changes in actual costs, while more effectively mitigating market power that may allow them to inflate their RSG payments. The percentage provision allows for reasonable treatment of a wide array of units with differing costs.

Figure 26 shows total real-time RSG payments in each month in 2013 and early 2014, including the payments that were actually mitigated under current framework and the additional mitigation that would have occurred under the proposed production-cost framework.

Figure 26: Real-Time RSG Payments By Mitigation Classification
2013–2014



This figure shows that a very low share of such offers was mitigated in the period shown. Under the proposed production-cost framework for RSG mitigation, an additional $3.5 million (23 percent) of RSG payments would have been mitigated in 2013. The importance of such a revision is more clearly demonstrated in early 2014 when inflated offer prices contributed to the sharp increase in RSG payments along with increases in gas prices. In this timeframe, an additional $9.3 million would have been mitigated under the proposed framework. This analysis demonstrates both the improved effectiveness and the importance of improving the mitigation measures that are applied to congestion-related commitments.

E. Dynamic NCAs

The current Tariff provisions (Section 63.4 of Module D) related to the designation of NCAs, where the MISO market is subject to the exercise of significant market power, are focused only on sustained congestion affecting an area. An NCA is an area defined by one or more constraints that are expected to bind for at least 500 hours in a 12-month period. The NCA thresholds are required to be calculated based on a historical 12-month period.

Consequently, when transitory conditions arise that create a severely-constrained area with one or more pivotal suppliers, an NCA can generally not be defined because it would not be expected to bind for 500 hours in a 12-month period. In addition, even if an NCA is defined, the conduct and impact thresholds are based on historical congestion, so they would not reflect the congestion for up to 12 months.

Although the conditions described above are transitory, they can result in substantial market power when an area is chronically constrained for a period of time. This often occurs when system changes occur related to transmission outages or generation outages. Once the congestion pattern begins, suppliers may quickly recognize that their units are needed to manage the constraints. To address this concern, we have recommended that MISO establish a dynamic NCA.

To identify when a dynamic NCA may have been beneficial, we have reviewed mitigation scenarios that we have conducted at thresholds that are 50 percent of the BCA thresholds (effectively $50 per MWh). Since this threshold is higher than what we would propose for the dynamic NCA, these results will identify fewer mitigation instances that would be mitigated by the dynamic NCA. Nonetheless, we have identified a number of instances over the past year when mitigation would have been warranted. Two examples presented in Section VI.B.2 of the Analytic Appendix illustrate why this provision would be beneficial. Both of these cases lasted less than two months, but the conduct that would have been mitigated during these periods increased prices at affected locations by roughly $150 per MWh in the hours that would have been mitigated and by $4 to $10 per MWh in the entire timeframes affected by the outages.

These examples show that current Tariff provisions are at times insufficient to effectively address episodes of local market power. Therefore, we recommend MISO expand Module D mitigation provisions to allow for greater flexibility in defining NCAs and to modify formulas for the threshold calculations to address transitory episodes of congestion. We recommend that the threshold for the dynamic NCA be set at $25 per MWh (rather than the default BCA thresholds of $100 per MWh) and be triggered by the IMM when it detects that: (1) such mitigation would be warranted on more than one day in a one-week period; and (2) the congestion is expected to continue in at least 15 percent of hours (more than double the rate that would be required to permanently define an NCA). This provision would help ensure that transitory network conditions do not convey substantial local market power that is not effectively mitigated under the MISO Tariff.

IX. Demand Response

Demand response improves reliability in the short term, contributes to resource adequacy in the long term, reduces price volatility and other market costs, and mitigates supplier market power. Therefore, it is important to provide efficient incentives for the development of DR and to integrate it into the MISO markets in a manner that promotes efficient pricing and other market outcomes. Table 4 shows overall DR participation in MISO, NYISO and ISO-NE in the prior four years.

Table 4: DR Capability in MISO and Neighboring RTOs
2009-2013

		2013	2012	2011	2010	2009
Midwest ISO	**Total***	**10,163**	**7,197**	**7,376**	**8,663**	**12,550**
	Behind-The-Meter Generation	3,411	2,969	3,001	5,077	4,984
	Load Modifying Resource	5,045	2,882	2,898	3,184	4,860
	DRR Type I	372	372	472	46	2,353
	DRR Type II	75	71	75	0	111
	Emergency DR	894	902	930	357	242
	Of which: LMR	366	380	404	N/A	N/A
NYISO	**Total**	**1,306**	**1,925**	**2,161**	**2,691**	**2,715**
	ICAP - Special Case Resources	1,175	1,744	1,976	2,103	2,061
	Of which: Targeted DR	379	421	407	489	531
	Emergency DR	94	144	148	257	323
	Of which: Targeted DR	40	59	86	77	117
	DADRP	37	37	37	331	331
ISO-NE	**Total**	**2,101**	**2,769**	**2,755**	**2,719**	**2,292**
	Real-Time DR Resources	793	1,193	1,227	1,255	873
	Real-Time Emerg. Generation Resources	279	588	650	672	875
	On-Peak Demand Resources	629	629	562	533	N/A
	Seasonal Peak Demand Resources	400	359	316	259	N/A

* Registered as of December 2013 All units are MW

The table shows that MISO had 10.2 GW of registered demand-response capability available in 2013, which makes up a larger share of capacity than it does in MISO's neighboring RTOs. MISO's capability comes in varying degrees of responsiveness. Most of the MISO DR is in the form of interruptible load (i.e., "Load-Modifying Resources", or LMR) developed under regulated utility programs, or Behind-The-Meter Generation (BTMG). MISO does not directly control either of these classes of DR, which cannot set the energy price, even under emergency conditions. In 2013, only 13 units providing 272 MW of capacity participated directly in

MISO's energy markets as "DRR", of which 10 that offered only supplemental reserves no longer do so. MISO considers DR a priority and continues to actively expand its DR capability—it added nearly 3 GW in 2013—including integrating "Batch-Load" DR (a demand resource with a cyclical production process). As surplus capacity dissipates, DR resources are expected to be deployed more frequently to satisfy peak loads and to respond to system contingencies. It is, therefore, important to ensure that real-time markets produce efficient prices when DR resources are deployed. One change that is particularly important is a modification to price-setting methodologies to let emergency actions and all forms of DR, including those not callable by MISO, contribute to setting efficient shortage prices in the markets. Failure to do so will undermine the efficiency of the market during peak periods and can serve as a material economic barrier to the development of new resources. MISO's proposed ELMP pricing methodology will improve the extent to which DR resources are integrated by allowing EDR to set energy prices. We recommend that MISO consider expanding this capability to LMR and BTMG.

Finally, the integration of DR in the resource adequacy construct is very important because it can potentially have a sizable effect on the price signals provided by MISO's capacity market. All demand response resources are treated comparable to generation resources in their ability to meet planning reserve margins in the Resource Adequacy Construct. However, LMR are not tested to verify their stated capability like generation resources are, and so are effectively granted a 100 percent capacity credit. When they were called in 2006, MISO received only 2,651 MW, or 42 percent, of the more than 6,000 MW of total claimed capability.

Despite the capacity market design issues we describe in this report, accurately accounting for the true capability of LMRs would potentially increase the clearing prices significantly in the PRA, making them more reflective of the actual supply and demand conditions in MISO. For example, the most recent PRA for the 2014–2015 planning year cleared at $16.75 per MW-day. This auction would have cleared at $84 per MW-day if the nearly 6,000 MW of LMR resources offered into the auction (or covered under a FRAP) received only a 50 percent capacity credit. Therefore, we recommend adopting testing procedures if practicable, and derating these resources based on their actual performance when called.

X. Recommendations

Although its markets continued to perform competitively and efficiently in 2013, we recommend MISO make a number of changes. We have organized the recommendations by the aspects of the market that they affect:

- Energy Pricing and Transmission Congestion
- External Transaction Scheduling and External Congestion
- RSG Cost Allocation and PVMWP Eligibility Rules
- Dispatch Efficiency and Real-Time Market Operations
- Resource Adequacy

A number of the recommendations described below were recommended in prior *State of the Market* reports. This is expected because some of the recommendations can require substantial software changes, stakeholder review and discussions, regulatory filings or litigation regarding Tariff changes. Since these processes can be time-consuming and software changes must be prioritized with other software projects, recommendations can take multiple years to complete. MISO addressed four of our past recommendations in 2013 or in early 2014; these are discussed at the end of this section. For any recurring recommendation, we include a discussion of the progress MISO has made to date and next steps required to fully address the recommendation.

A. Energy Pricing and Transmission Congestion

Efficient energy pricing in the real-time market is essential. Even though a very small share (one to two percent) of the energy produced and consumed in MISO is settled through the real-time market, the spot prices produced by the real-time market affect the outcomes and prices in all other markets. For example, prices in the day-ahead market, where most of the energy is settled, should reflect the expected prices in the real-time market. Similarly, longer-term forward prices will be determined by expectations of the level and volatility of prices in the real-time market. Therefore, one of the highest priorities from an economic efficiency standpoint must be to produce real-time prices that accurately reflect supply, demand, and network conditions. The following three recommendations address this area.

2008-2[23]: Develop provisions that allow non-dispatchable DR (including interruptible load and BTMG) to set energy prices in the real-time market.

As the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by interruptible load, BTMG or other forms of DR. If these resources cannot set prices in the real-time market, MISO will be understating the marginal value of energy during these periods. Prices in these hours play a crucial role in sending efficient long-term economic signals to maintain adequate supply resources and to develop additional demand-response capability. Therefore, allowing DR to set real-time energy prices will improve incentives to schedule imports and exports, to schedule load in the day-ahead market (and reduce RSG costs), and to invest in resources needed to maintain adequate supplies in MISO.

Status: MISO agrees with allowing non-dispatchable DR to set price real-time prices. MISO is currently planning to allow EDR to set prices through ELMP in the fourth quarter of 2014. However, MISO calls for the deployment of LMR and BTMG (which total nearly 8.5 GW) before it calls on EDR. Since LMR and BTMG will not set prices under the current ELMP proposal, real-time prices are likely not to reflect curtailment costs when MISO deploys DR. MISO has developed a conceptual design for enabling LMR and BTMG to set price when called. MISO is planning for implementation by September 2015.

Next Steps: The progress made to allow Type I DR and EDR resources to set prices through ELMP has been substantial and we have previously suggested that this framework be expanded to address this recommendation. MISO's conceptual design is consistent with this approach and we will be providing detailed comments. We believe that MISO's target date of September 2015 is feasible.

23 To facilitate tracking, in this and future *State of the Market* reports the numbering for a particular recommendation will be held constant across annual and quarterly reports. A recommendation of 2008-3 indicates the third recommendation listed in the 2008 State of the Market Report. Beginning in the 2013 report all new recommendations will be listed sequentially as they appear in the Recommendations section as 2013-1, 2013-2, and so on.

2012-2: Implement a five-minute real-time settlement for generation and external schedules.

MISO clears the real-time market in five-minute intervals and schedules physical schedules on a fifteen-minute basis. However, it settles both physical schedules and generation on an hourly basis. This can create inconsistencies between the dispatch signal and the hourly prices that can cause generators to have the incentive to not follow the dispatch signal or to simply be inflexible. This inconsistency is only partially addressed by the PVMWPs. Implementing this recommendation will improve the incentives for generators to follow dispatch instructions and provide more flexibility, and for participants to schedule imports and exports more efficiently.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. MISO has agreed this recommendation would have significant benefits, but continues to evaluate the feasibility and costs of implementation.

Next Steps: We believe MISO already has the metering and data necessary to support this recommendation, and implementing it will require only modest changes to MISO's existing settlement calculations. MISO should continue to evaluate the costs of this proposal and seek stakeholder input and approval. Implementing five-minute settlements for physical schedules has been identified as a prerequisite for MISO fully complying with the scheduling requirements of FERC Order 764.

2012-5: Introduce a virtual spread product.

Over two-thirds of price-insensitive volumes (and 21 percent of all volumes) in 2013 were "matched" transactions. To the extent that the matched transactions are attempting to arbitrage congestion-related price differences, a virtual product to allow participants to do this price sensitively would be more effective and efficient. Participants using such a spread product would specify the maximum congestion difference between two points they are willing to pay (i.e., schedule a transaction). This would prevent the participant from engaging in transactions that are highly unprofitable for the participant and produce excess day-ahead congestion that can cause inefficient resource commitments.

Status: This recommendation was originally proposed in our *2012 State of the Market Report*. Throughout 2013, MISO has been evaluating the feasibility, costs and benefits of developing such a product. MISO has held a number of workshops with stakeholders to explore the development of such a product.

Next Steps: MISO should continue its development of the virtual spread product and work with stakeholders to prioritize and schedule its implementation.

2012-9: Modify the mitigation measures to allow the definition of a "dynamic NCA" that is utilized when network conditions create substantial market power.

The current Tariff provision (Section 63.4 of Module D) related to the designation of NCAs is focused only on chronic congestion that creates sustained local market power. However, transitory conditions (transmission or generation outages) can arise that create a severely-constrained area where the market is vulnerable to the exercise of substantial local market power. Although these areas would not satisfy the criteria to be defined as permanent NCAs, we have concluded that under these transitory conditions, the current Tariff provisions are insufficient to effectively address the resulting local market power. This recommendation would expand Module D mitigation provisions to allow temporary "dynamic" NCAs to be defined while the conditions persist and a fixed conduct and impact threshold of $25 per MWh would be utilized.

Status: The IMM has continued to evaluate instances that warrant the definition of a dynamic NCA and developed a proposed trigger for defining a dynamic NCA.

Next Steps: The IMM will work with MISO to develop proposed Tariff revisions to address this recommendation and present the proposed revisions to MISO's stakeholders.

B. External Transaction Scheduling and External Congestion

Efficient scheduling of imports, exports, and wheels is very important because it affects not only the market prices and congestion in MISO, but throughout the Eastern Interconnect. We have seen a number of cases where poor scheduling of transactions between MISO and PJM has contributed to substantial shortages and price spikes in one area or the other. We have been evaluating the scheduling processes and the interface prices the RTOs post that provide the incentives that motivate participants to schedule transactions. This evaluation has indicated the need for improvements that are addressed by the recommendations below.

2012-3: Remove external congestion from interface prices to eliminate excess payments and charges to physical transactions.

When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it generally duplicates the congestion pricing by the external system operator. For example, PJM already includes the congestion effects of external transactions in its interface pricing so when MISO includes these same effects in its interface prices, the resulting congestion settlements are redundant and inefficient. The excessive settlement of congestion in the interface prices produces the following adverse results:

- The excess payments can result in higher negative ECF, market-to-market costs, or FTR underfunding.
- The excess payments can motivate participants to schedule inefficient transactions, while the excess charges can discourage efficient transactions.

The excess payments are not limited to market-to-market constraints in PJM. They also occur on constraints in other areas that MISO activates when the other system operator calls a TLR. These TLR constraints raise more serious concerns than the external market-to-market constraints do because MISO typically prices TLR constraints at shadow costs that are many times higher than the value of the constraints in the neighboring area. Hence, the TLR congestion included in interface prices results in highly distorted incentives to schedule imports and exports. To fully address these concerns, we are recommending that MISO eliminate the portions of the congestion components of the interface prices associated with the external constraints.

Status: This recommendation was originally made in our 2012 SOM, although it was previously raised in our 2011 SOM. Throughout 2013 and continuing into 2014, we have been working with MISO, PJM, and stakeholders through the Joint and Common Market Stakeholder group to achieve a consensus on the nature and costs of the problem, and on a preferred solution. While a consensus has been reached on the nature and the range of costs associated with the problem, no consensus has yet been reached on the best solution.

Next Steps: MISO can address a sizable portion of this problem by modify its interface pricing and should encourage PJM to do the same. It is not essential that MISO and PJM modify their interface pricing at the same time so MISO should not wait for consensus with PJM to emerge.

2005-2: Expand the JOA to optimize the interchange with PJM to improve the price convergence with PJM.

The RTOs continue to discuss allowing participants to submit offers to transact within the hour if the difference between MISO's and PJM's real-time prices is greater than the offer price. This change, or others that will allow the interface between the markets to be more fully utilized, would generate substantial benefits by allowing lower-cost resources in one area to displace higher-cost resources in the other area. Additionally, it will improve reliability in both areas and avoid types of shortages MISO experienced in 2013 that were in large part caused by poor utilization of the interface with PJM.

Status: This recommendation was originally proposed by the IMM in 2005 and MISO has been discussing options with PJM. PJM and the NYISO have developed Coordinated Transaction Scheduling (CTS), which allows participants to submit intra-hour interchange transactions with a spread bid price. The RTOs could then strike these transactions on a 15 minute basis when the spread in prices is sufficient large.

In mid-April, 2014, MISO and PJM staff held their first joint workshop with stakeholders on this topic and PJM supports a coordinated transaction scheduling process with MISO. However, PJM has indicated a desire to complete its implementation of CTS with NYISO before pursuing coordinated interchange with MISO.

Next Steps: We recommend that MISO complete its development of the CTS proposal with PJM and move to schedule this project at the earliest feasible date.

2012-4a: Improve external congestion processes by modifying how relief obligations are calculated by basing them on *Net* Market Flows, not gross forward flows.

MISO reports its Market Flow to the IDC in two ways: gross forward flows and gross reverse flows. MISO receives a relief obligation based solely on its forward-direction Market Flows, even though the *net* Market Flows represent the true impact of MISO's dispatch on the constraint. MISO has frequently received relief obligations for constraints when its dispatch is already unloading the constraint. Attempting to provide relief in these cases has caused MISO to incur inefficient costs and can result in substantial FTR underfunding.

Status: MISO has deferred further evaluation of this recommendation pending the completion of the NERC Parallel Flow Visualization project.

Next Steps: MISO should explore potential changes in its procedures and agreements that could address this recommendation, even in advance of the completing the Parallel Flow Visualization project.

2012-4b: Improve the pricing of external congestion associated with external constraints by setting the MVL on external (non-M2M) flowgates at a reasonable level.

When MISO gets a relief obligation on an external (non-M2M) flowgate, MISO binds the external flowgate at its internal default TCDC ranging up to $2,000. Because the relief is often costly to provide, the high TCDC results in MISO incurring congestion costs that are often many times higher than the value of the constraint (i.e., the cost of managing the constraint by the monitoring RTO). In fact, we show in this report that in 78 percent of periods in which an SPP TLR constraint is binding in MISO, the constraint is not binding in SPP (i.e., costly relief is being provided by MISO that has no value to SPP). The dispatch and resulting congestion costs incurred in these cases is highly inefficient.

Status: When MISO filed its proposed TCDCs for external flowgates at values consistent with internal constraints rated 161kV or higher, the IMM filed comments demonstrating the inefficiency of these values. Nonetheless, FERC that approved these values, agreeing with MISO that the two classes of facilities are comparable. The IMM filed for rehearing, which was granted on January 13, 2014, and is still pending at FERC under Docket No. ER13-2295.

Next Steps: This report contains additional evaluation of the costs and inefficiencies of external congestion. We encourage MISO to review these results and conduct its own evaluation to determine appropriate TCDC levels for external constraints in the long run.

C. Guarantee Payment Eligibility Rules and Cost Allocation

Failure to allocate RSG costs to those market participants that cause them will produce inefficient incentives by: (a) discouraging efficient conduct that does not cause the costs and (b) not discouraging conduct that does cause the costs. Therefore, the allocation of RSG costs is very important because it affects the performance of the market.

In 2013, MISO filed a series of proposed tariff revisions consistent with our *2012 State of the Market Report* recommendations. The proposed revisions addressed problems with the allocation of real-time RSG costs that over-allocated costs to market-wide deviations and under-allocated costs to deviations that affected constraints.

Additionally, we made recommended changes in the eligibility rules for PVMWP and RSG to address gaming strategies that can result in unjustified payments. With one exception, all of these recommendations have now been adopted. The remaining recommendation in this area is discussed below.

<u>2013-1</u>: Allocate real-time RSG costs only to harming deviations (pre- and post-NDL).

MISO distinguishes between deviations that occur prior to the NDL and those that occur after it. Only harming net participant deviations prior to the NDL are allocated RSG costs, whereas all post-NDL deviations (helping and harming) are allocated real-time RSG costs. Although these post-NDL helping deviations may not reduce RSG (which is why we propose not including them in the market-wide netting in the prior recommendation), we do not believe that they cause RSG. Hence, they should not be allocated real-time RSG.

<u>Status</u>: MISO filed to remedy this problem along with a number of other allocation issues. In March 2014, FERC accepted most of the proposed RSG allocation changes, but did not approve this proposed change because it found that MISO's evidentiary support was insufficient.

<u>Next Steps</u>: MISO is planning on re-filing the proposed change in a future FERC filing with additional evidence and analysis for this proposal.

2013-2: Improve allocation of VLR costs by identifying VLR commitments made by the DA market.

To satisfy a number of local reliability requirements in the MISO South region, MISO utilizes both the Multi-day Forward Reliability Assessment (MFRAC) and the Day-Ahead Commitment process. MISO's MFRAC process generally commits resources with longer startup times when necessary to meet the local reliability requirements. For all other resources, MISO relies on the day-ahead market to commit the necessary resources in these load pockets by modeling the local commitment constraint in each of these areas. Unfortunately, there is no way currently to tell why a resource committed through the day-ahead market was committed, so none of them are flagged as VLR commitments. To the extent that the local commitment constraints are binding and cause the commitment of resources that receive day-ahead RSG, these costs should be allocated locally. Therefore, we recommend that MISO develop a means to identify VLR commitments that are made through the day-ahead market so the related RSG costs can be allocated consistent with the VLR methodology.

Status: This is a new recommendation.

Next Steps: MISO is evaluating the current Operating Guides that reflect the local commitment requirements described above and may implement new Guides more compatible with market operations on July 1, 2014. To the extent that these Operating Guides continue, MISO should identify available options to determine which resources committed in the day-ahead market would not have been committed but for the Operating Guides. These options may include running a parallel SCUC process without the local commitment requirements to identify units that were only committed in the case that includes the local requirements. MISO should also determine what tariff changes are needed to classify these commitments as VLR so the associated RSG can be allocated in a manner consistent with cost-causation.

2010-11: Improve the efficiency of reserve scheduling by eliminating guarantee payments to deployed spinning reserves.

Compensating spinning reserve suppliers for out-of-market deployment costs when they are called on to produce energy leads to an inefficient selection of spinning reserve resources because these expected deployment costs are not considered when resources are scheduled.

Eliminating these payments, including RTORSGP and real-time RSG payments, for spinning reserve deployments will improve reserve market efficiency by causing expected deployment costs of operating reserves to be reflected in participants' offers. This in turn will allow MISO to schedule those resources with the lowest total costs, including deployment costs. It will also allow these costs to be efficiently reflected in spinning reserve prices.

Status: This recommendation was originally made in the *2010 State of the Market Report* and MISO has presented this to its stakeholders. The stakeholders recommended that MISO evaluate potential alternatives to resolve the issue, although we continue to believe that this is the simplest and lowest-cost means to address this issue.

Next Steps: MISO should complete the requested evaluation and work with its customers to develop proposed Tariff changes.

2013-3: Improve the market power mitigation measure applicable to RSG payments.

Periods of chronic congestion occurred over the past year that required the repeated commitment of certain resources. In these cases, certain suppliers are often pivotal and can generate large increases in RSG payments without being mitigated. Based on our evaluation of these patterns, we find that the current Tariff provisions related to mitigation of RSG of commitments made to manage congestion have not been fully effective. This is due in part to the fact that the conduct test is applied to each offer parameter individually and the impact test threshold is too large.

When mitigation measures were developed to mitigate RSG associated with VLR commitments, a new framework was introduced utilizing a conduct test based on the aggregate as-bid production cost of a resource. This method recognizes the joint impact of all of the resource's bid parameters. Additionally, the VLR production cost-based conduct test effectively serves as an impact test as well. When units committed for VLR require an RSG payment, every dollar of increased production costs will translate to an additional dollar of RSG.

Our evaluation of the VLR mitigation framework suggests that it is more effective at addressing market power exercised to increase RSG payments. Therefore, we are recommending that this framework be applied for all RSG mitigation. Because market power concerns associated with the VLR commitments are much greater, it is reasonable to employ a tighter threshold for VLR mitigation than for other RSG mitigation. Therefore, we evaluated a conduct and impact threshold equal to the higher of $25 per MWh or 25 percent in this report and recommend MISO adopt these thresholds.

Status: This is a new recommendation.

Next Steps: MISO should work with the IMM to develop proposed Tariff revisions to address this recommendation and present this recommendation to its stakeholders.

D. Improve Dispatch Efficiency and Real-Time Market Operations

As discussed above, the efficient performance of the real-time market is essential to achieving the full benefits of competitive wholesale electricity markets, which include satisfying the system's needs reliably and at the lowest cost. MISO's real-time operators play an important role in this process because they monitor the system and make a variety of changes to parameters and other inputs to the real-time market as necessary. Each of these actions can substantially affect market outcomes.

One of the principal challenges to achieving efficient real-time outcomes is the five-minute time horizon of the real-time market. When the needs of the system require that resources ramp up or down rapidly, substantial costs can be incurred and real-time prices can become highly volatile to reflect these costs. It is these ramp demands that have caused MISO's real-time energy prices to be more volatile than any of the other RTOs in the Eastern Interconnect. These ramp demands can be satisfied at a much lower cost if they are anticipated and if the dispatch of resources is modified to account for them over a timeframe longer than five minutes, or if the system holds low-cost ramp capability that can be utilized when unexpected ramp demands arise. The following three recommendations seek to improve on these processes.

2011-7: Implement a ramp capability product to address unanticipated ramp demands.

The LAD recommendation addresses ramp demands that can be foreseen by MISO. Some of the most significant ramp demands MISO faces, however, are unforeseen in advance. These include unforeseen ramp demands associated with unit outages, changes in wind, and changes in "non-conforming" load. To address these unforeseen ramp demands, MISO could procure ramp capability. This can be done by establishing ramp capability targets along with economic values for the ramp capability (e.g., a ramp capability demand curve). Even at a relatively low demand curve level, the real-time market can likely make low-cost tradeoffs to maintain a higher level of ramp capability. Because it would address unanticipated ramp needs, this recommendation would be valuable independent of the LAD.

Status: MISO has continued to develop this market product in a conceptual design.

Next Steps: MISO expects to complete a conceptual design by the fall of 2014. Currently MISO is scheduling the ramp product to be in production by September 2015.

2012-12a: Develop enhanced tools to identify units that are effectively derated or not following dispatch so that they may be placed off control.

MISO's current set of tools used to monitor the performance of units in real time are not designed to identify units that may be chronically unresponsive to dispatch signals over multiple intervals. Consequently, a unit that may be effectively derated by large amounts and unable to follow dispatch points may not be identified by MISO's current operating tools and procedures. In 2012, we found numerous examples where resources were well below their economic output levels because they were effectively derated, but did not update their offer parameters to show that they were derated or put off control by MISO. Although there were fewer such cases in 2013, it was still a significant issue.

Unreported derates impact reliability and can result in substantial unjustified make-whole payments and avoided RSG charges. This recommendation would allow the operators to recognize units in this condition so that they can place the units off control, which would address the concerns described above.

Status: MISO agrees with this recommendation and has been working to develop new procedures and tools to identify unreported derates. However, based on our review of the initial design of the new operator tool MISO is planning to develop, we conclude that it will not be fully effective in identifying unreported derates. MISO also has a related project to enable participants to update offers within the hour that is scheduled for implementation in 2015.

Next Steps: We continue to monitor for unreported derates and refer suppliers to FERC as appropriate. Additionally, MISO should modify the design of its new operator tool to ensure that it will be effective and we will continue to provide comments on the design.

2012-12b: Tighten thresholds for uninstructed deviations.

All RTOs have a tolerance band that defines how much a resource's output can vary from the RTO's dispatch instruction before the supplier is penalized for uninstructed deviations. MISO's tolerance band of eight percent (which also requires the deviation occur in four consecutive intervals) is substantially more lenient than those of other RTOs.[24] Additionally, by establishing a threshold that is a fixed percent of the dispatch instruction, the deviation tolerance band effectively becomes larger as a resource is ramped from its minimum output level to its maximum output level.

To address these concerns, we recommend MISO adopt thresholds based on resources' ramp rates that are tighter than its current thresholds. This report includes a specific proposal in Section V.C.6. This will improve suppliers' incentives to follow MISO dispatch signals and, if used to determine whether a resource should remain eligible for DAMAP and RTORSGP payments, will also help address the concerns we have raised regarding unreported unit derates.

Status: MISO agrees with this recommendation, and is evaluating our proposed revisions to the uninstructed deviation threshold.

Next Steps: We will work with MISO on finalizing and testing revised rules. Once this is completed, MISO will need to present the proposal to its stakeholders and file the revised thresholds at FERC.

2011-10: Implement procedures to utilize provisions of the JOA that would improve day-ahead market-to-market coordination with PJM.

Under the JOA each RTO has the option to request additional FFE on M2M constraints and to compensate the responding RTO based on the responding RTO's DA shadow price. This is a valuable provision because a constraint binding in the day-ahead market at the FFE can be costly

24 MISO's threshold also includes a minimum of six MW and a maximum of 30 MW.

and inefficient for constraints that are not expected to bind in real time or bind at levels that would enable an RTO to exceed its FFE in real time at a very low cost. Neither PJM nor MISO has ever requested additional FFE in the day-ahead market. Implementing this recommendation would likely improve the resource commitments in both areas.

Status: MISO has been working with PJM in evaluating this recommendation and has committed to stakeholders and FERC that it will meet intermediate deadlines to complete prerequisite projects including improved data exchange. MISO expects to complete cost-benefit studies for day-ahead coordination with PJM in the third quarter of 2014, and to make an implementation decision in the fourth quarter.

Next Steps: The RTOs should continue to work together to develop more detailed procedures and to complete their cost-benefit evaluations of this project to support their decisions to move forward.

2012-16: Reorder MISO's emergency procedures to utilize demand response efficiently.

As noted above, as the capacity surplus falls in MISO, the peak needs of the system will increasingly be satisfied by interruptible load, BTMG or other forms of DR. However, these resources cannot be called by MISO before it has invoked a number of other emergency actions that are costly and adversely impact the market. This recommendation would allow MISO to utilize these resources in a more efficient manner.

Status: Limited progress has been made to date.

Next Steps: MISO should review the existing DR resources in MISO to estimate the costs of calling on them to curtail. This information would be valuable in responding not only to this recommendation, but also to Recommendation 2008-2 (to enable DR to set prices).

2012-17: Modify the market systems to recognize supplemental reserves being provided from quick-start units when they are in the process of starting.

When resources providing supplemental reserves are committed, the reserves are shifted to online resources. Unfortunately, MISO does not perceive that the committed resource is providing reserves or energy until the unit is synchronized and providing energy. Hence, all capacity from the resource will appear to be lost for five to 15 minutes. During this period, the quality of reserve capability is actually enhanced (not degraded) because the resource can provide energy and reserves more quickly to the system once it is online. This issue caused two operating reserve shortages and contributed to nine operating reserve price spikes of at least $100 per MWh. This recommendation will prevent this inaccurate transitory capacity loss that can result in artificial operating reserve shortages.

Status: The impacts related to this issue have fallen because MISO has modified its operating practices to avoid committing resources that are providing offline supplemental reserves. Nonetheless, we have presented MISO with additional evidence of shortage pricing events in 2013 that were not appropriate.

Next Steps: MISO should continue to evaluate this recommendation and identify the lowest-cost means to address it.

E. Resource Adequacy

Reasonable resource adequacy provisions and a well-functioning capacity market are intended to provide economic signals, together with MISO's energy and ancillary services markets, to establish efficient incentives to govern investment and retirement decisions. These economic signals will be increasingly important as planning reserve margins in MISO fall due to the compliance costs of new environmental regulations and due to low prevailing energy prices, both of which will increase retirements of uneconomic units. MISO filed proposed changes to its Resource Adequacy Construct in 2011 that should improve price signals and reliability. However, there remain a number of critical issues that are undermining the economic signals provided by the MISO markets. The recommendations in this subsection are intended to address these issues to help ensure that the market will facilitate investment in the resources over the long term that are necessary to maintain reliability.

2008-11: Remove inefficient barriers to capacity trading with adjacent areas.

A number of existing barriers limit capacity trading between MISO and PJM, which include access to transmission capability, deliverability requirements, and an unclear application of capacity obligations to external suppliers. These barriers substantially distort the capacity prices in both markets, thereby providing inaccurate economic signals to invest and retire resources. Eliminating these barriers will require the cooperation of both RTOs.

Status: MISO has been developing proposals to address this recommendation, but PJM has generally opposed changes in this area. We have sought a mandate from FERC to compel the RTOs to collaborate on a proposal to address this issue. It held a technical conference on this issue and opened a docket, but FERC has not yet mandated resolution.

Next Steps: If no mandate is provided by FERC, MISO should continue to refine its proposals and discuss them with PJM in an attempt to achieve a consensus.

2010-14: Introduce a sloped demand curve in the RAC to replace the current vertical demand curve.

The use of only a minimum requirement and deficiency charges to represent capacity in MISO results in an implicit vertical demand curve for capacity. This does not reasonably reflect the reliability value of capacity and understates capacity prices as capacity levels fall toward the minimum requirement. This is particularly harmful as large quantities of resources are presently facing the decision to potentially retire in response to new environmental regulations that will require substantial compliance costs.

A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement. It also will produce more efficient and stable capacity prices, particularly as the market moves toward the minimum planning reserve requirement. If this recommendation is not addressed, the MISO markets will not facilitate efficient investment and retirement decisions by participants that will sustain an adequate resource base. Instead, the region will have to rely exclusively on the States requiring their regulated utilities to build new resources.

Status: MISO is developing principles governing future market developments, including changes in its resource adequacy provisions and processes. The principles include the objective of facilitating efficient investment so they are consistent with this recommendation. However, there is currently no consensus among the participants and States regarding this objective.

Next Steps: MISO should continue to work with its stakeholders and OMS to move toward a consensus regarding the economic objectives of the resource adequacy construct. The IMM will support this process by continuing to show the benefits to MISO of establishing efficient capacity price signals, which include lowering the costs of satisfying the planning reserve requirements for both regulated and unregulated participants alike.

2011-14: Evaluate capacity credits provided to LMR to increase their accuracy.

In order for the capacity market to produce outcomes that are consistent with market fundamentals, it is important that the supply be accurately represented. LMR (excluding BTMG) can currently be fully deducted from an LSE's capacity requirement under Module E. This effectively provides a 100 percent capacity credit to DR resources that are not tested to ensure their capability. These resources have been shown to only have the ability to provide a fraction of the total claimed capability in the past. For example, MISO has reported that less than one-half of these resources were available during the winter shortages in early 2014. In addition, only roughly one-half of this DR capability was responsive when they were deployed during shortage conditions in summer 2006. If this capability had been derated by 50 percent in the most recent PRA conducted in April 2014, the price would have risen from roughly $16 to $84 per MW-day. This shows that qualifying this capability at a level that accurately reflects its expected ability to reduce load can substantially affect the PRA results and economic signals provided by MISO's markets. Therefore, we continue to recommend adopting testing procedures if possible, and/or derating these resources based on their actual performance or expected performance when called.

Status: In the last couple of years some progress has been made in requiring additional documentation of capability through State programs, auditors, or MISO mock tests. In addition, MISO has continued to develop improved communication systems to enable LBAs to report curtailment of registered resources and voluntary curtailments of unregistered resources. While MISO's efforts provide more audit capability and situational awareness, these resources are still not tested in any way comparably to other resources and the limited deployment experience suggests response rates far below other resource categories.

Next Steps: Evaluate alternatives and work with stakeholders to develop reasonable changes to Module E that address this recommendation.

2013-4: Improve alignment of the PRA and the Attachment Y process governing retirement and suspensions.

Ideally, participants should be able to utilize the PRA to make decisions whether to retire or suspend units, or to return a unit to service from suspension. This allows them to make efficient retirement or suspension decisions. For example, a supplier may submit an offer into the PRA at a price that would cover its going forward cost (or the cost that would justify returning from suspension). If such an offer clears, the unit is economic to be in service during the planning year.

Suppliers that have submitted an Attachment Y retirement request currently lose their interconnection rights as of the specified retirement date. Furthermore, units that are currently suspended cannot qualify to offer into the PRA. These rules should be modified to allow the broadest possible participation in the PRA, and to allow participants ultimate decisions to be efficiently facilitated by the PRA. Finally, capacity resources should have more flexibility to retire or shut down temporarily prior to the end of the planning year if their capacity is not needed. Flexibility will improve market efficiency by reducing inefficient barriers to participating in the PRA.

Status: This is a new recommendation.

F. Recommendations Addressed in 2013

In 2013 and early 2014, MISO addressed a number of past recommendations by implementing changes to its market software, operating procedures, or Tariff provisions. These recommendations are discussed below.

2012-7a: Modify eligibility requirements to address gaming issues associated with PVMWPs.

We identified a number of gaming opportunities under the current PVMWP eligibility rules that could enable participants to increase PVMWP in a manner that was not intended by the rules. The specific gaming issues have been discussed with MISO and FERC. MISO made two filings that address these concerns by changing the eligibility rules associated with these payments. These changes cause any supplier engaging in the gaming conduct to become ineligible for the payments. FERC approved these changes, which have eliminated the incentive to engage in these strategies.

2012-7b: Correct the mitigation rule governing authority over PVMWP and RSG eligibility.

The Tariff provides authority for MISO to file for the removal of eligibility for make-whole payments for resources identified as being engaged in conduct to increase these payments unjustifiably. The purpose of this provision is to effectively address any unforeseen flaws in MISO's guarantee payments that provide an opportunity for market participants to engage in gaming. However, the Tariff provision did not refer specifically to PVMWP, but rather to "MRD MWP", which is an undefined term. To correct this, MISO filed Tariff changes that provide MISO the intended authority to stop gaming strategies until it has the opportunity to modify the rules. FERC approved this change effective October 17, 2013.

2012-6: Improve the allocation of real-time RSG costs to make it more closely aligned with causes of the costs.

Status: This recommendation included three sets of improvements, some of which were originally proposed in 2011 and 2012. In 2013, MISO filed proposed Tariff changes supported by the IMM to address the three areas identified in the recommendation. FERC held a technical conference and ultimately approved most of the changes in early 2014. One important change—allocating real-time RSG only to harming pre- and post-NDL deviations—was not approved because FERC asserted that sufficient evidence was not provided. We are working with MISO to develop the additional evidence needed to address the remaining item that was not approved. MISO plans to finalize Tariff revisions and file proposed modifications with FERC shortly. Recommendation 2013-1 above pertains to this change.

2011-8: Eliminate the transmission constraint deadband.

The transmission constraint deadband was an algorithm that would reduce transmission constraints' limits by a small amount once the constraint begins binding. The deadband was intended to reduce price and generator dispatch volatility by helping ensure that once constraints were binding, they continued to do so. However, IMM case studies showed that it actually increased volatility because it contributed to unmanageable congestion that often resulted in sharp LMP changes. We estimated that the deadband accounted for 19 percent of all congestion value in MISO during 2011. It also reduced the utilization of the transmission system by binding constraints at levels less than their physical capability. This recommendation was fully addressed when MISO deactivated the transmission constraint deadband on October 1, 2013.

Schedule SLK-5

Is Deemed

Highly Confidential

In Its Entirety

Schedule SLK-6

Is Deemed

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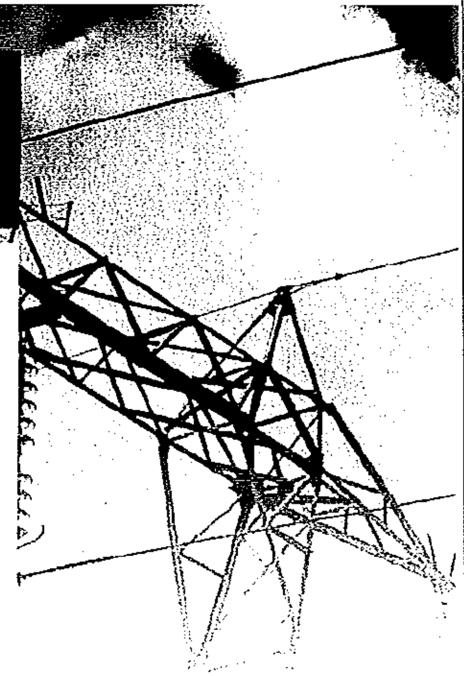
In Its Entirety

MVPs Create Jobs, Benefits for States

MISO's Multi-Value Projects portfolio, or MVPs, will create thousands of jobs. Estimates include the following:

- Creation of 17,000 - 39,800 direct (construction) jobs
- Between 28,400 and 74,000 total jobs will be created. This includes construction, supplier and other downstream opportunities.



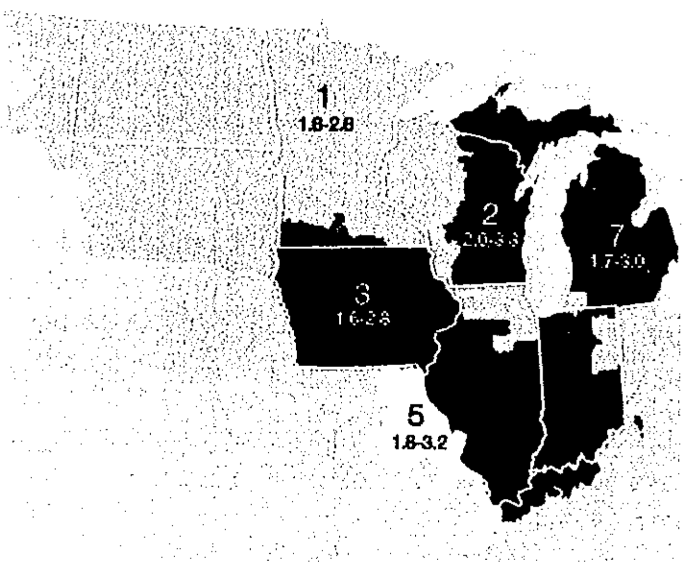
MVPs Save States Money

As a result of MVPs, consumers will see economic benefits ranging from 1.8 to 3.0 times the costs. These benefits include:

- $12.4 billion to $40.9 billion from enabling low-cost generation to displace higher-cost generation
- $28 million to $87 million from more efficient dispatch of operating reserves
- $111 million to $396 million from reductions in energy wasted on transmission losses, reducing future generation investment required to serve those losses
- $1,354 million to $2,503 million in benefits through supporting a regional wind integration methodology
- $1,023 million to $5,093 million from reduced future Planning Reserve Margin Requirements, which reduces installation of future generation to meet this requirement.
- $226 million to $794 million in avoided costs for reliability projects that would otherwise need to be constructed.

Did you know?

- Transmission planning ensures greater reliability throughout MISO, identifying areas of congestion and recommending transmission upgrades.
- MISO matches the appropriate cost allocation method with each project's driver and business case to ensure project costs are spread commensurate with benefits.
- Multi-Value Projects provide benefits beyond just meeting local energy and reliability needs.



Benefit/Cost Ratio Ranges
Local Resource Zones

Regional Benefits

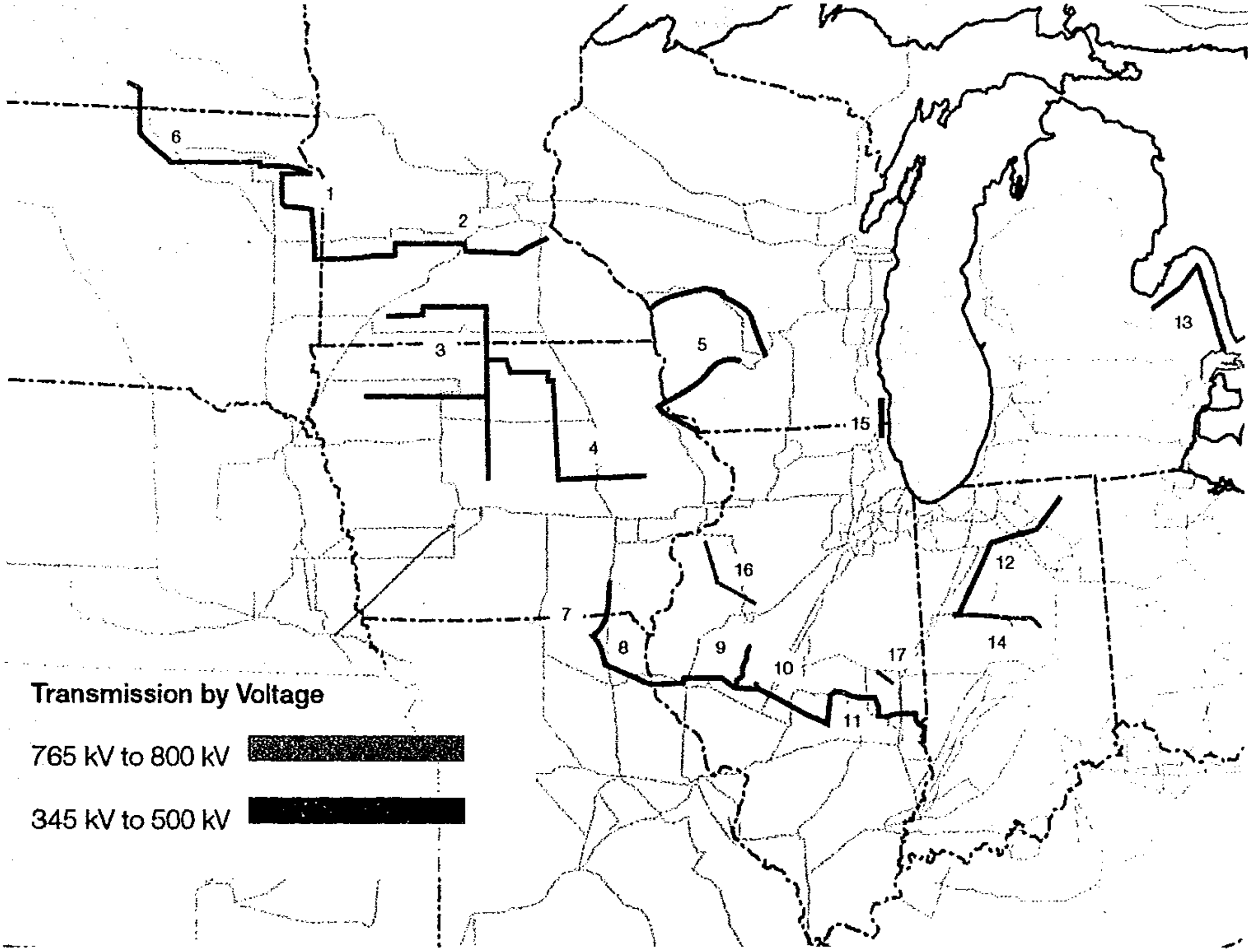
MISO projects the 2011 MVP portfolio will realize the following benefits for the entire MISO footprint:

- Average residential customer's return on investment: $23 annual return on an $11 per year investment.
- Projected benefits: $15.6 billion - $49.3 billion*
- Proposed capital cost: $5.2 billion*

MISO Zones & Planning

The MVP portfolio will deliver reliability, public policy and economic benefits across the system. MISO's energy zones are designed to optimize wind generation placement and to minimize distance to other fuel sources such as natural gas. When connected to the overall grid by the MVP projects, the zones will enable access to low-cost energy for the entire MISO footprint.

*2011 present value dollars

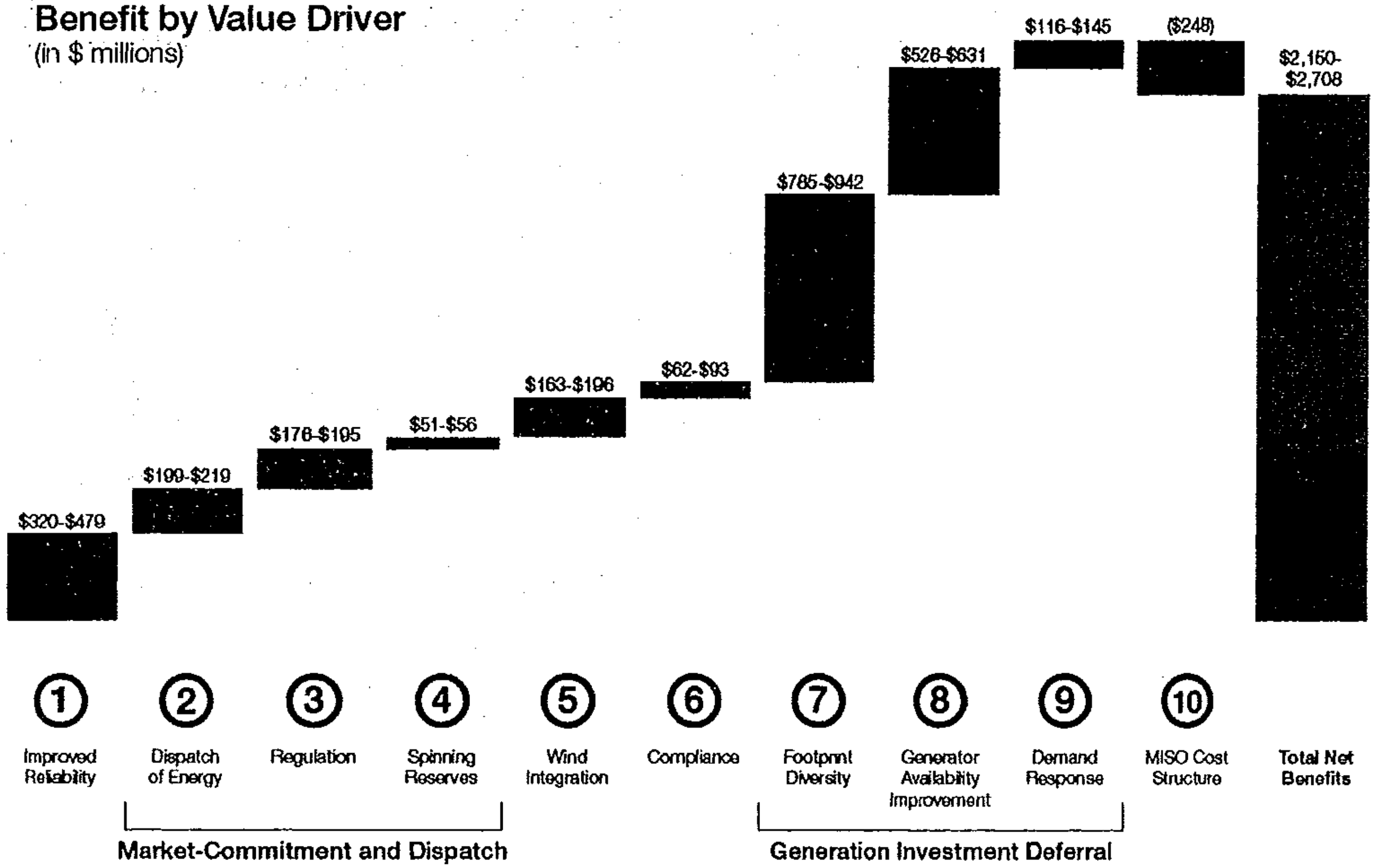


Project Name	State(s)	Voltage
1. Big Stone – Brookings	SD	345 kV
2. Brookings – SE Twin Cities	SD-MN	345 kV
3. Lakefield Jct.-Winnebago – Winco – Burt area & Sheldon – Burt area – Webster	MN-IA	345 kV
4. Wilson – Lime Creek – Emery - Blackhawk – Hazleton	IA	345 kV
5. N. LaCrosse-N. Madison-Cardinal & Dubuque Co.-Spring Green-Cardinal	WI	345 kV
6. Ellendale – Big Stone	ND-SD	345 kV
7. Adair – Ottumwa	IA-MO	345 kV
8. West Adair – Palmyra Tap	MO	345 kV
9. Palmyra-Quincy-Meredosia-Ipava & Meredosia-Pawnee	MO-IL	345 kV
10. New Pawnee-Pana	IL	345 kV
11. Pana-Mt. Zion-Kansas-Sugar Creek	IL	345 kV
12. Reynolds-Burr Oak-Hiple	IN	345 kV
13. Michigan Thumb Loop Expansion	MI	345 kV
14. New Reynolds-Greentown	IN	765 kV
15. Pleasant Prairie-Zion Energy Center	WI-IL	345 kV
16. Fargo-Oak Grove	IL	345 kV
17. Sidney-Rising	IL	345 kV

MISO

MISO 2011 Value Proposition

Benefit by Value Driver
(in $ millions)



1 **Improved Reliability - $320-$479 million in annual benefits** MISO's broad regional view and state-of-the-art reliability tool set enables improved reliability for the region as measured by transmission system availability.

2 **Dispatch of Energy - $199-$219 million** MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.

3 **Regulation - $176-$195 million** With the MISO Regulation Market, the amount of regulation required within the MISO footprint dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than several non-coordinated regulation targets within the footprint.

4 **Spinning Reserves - $51-$56 million** Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement declined, freeing low-cost capacity to meet energy requirements.

5 **Wind Integration - $163-$196 million** MISO's regional planning enables more economic placement of wind resources in the region. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.

6 **Compliance - $62-$93 million** Before MISO, utilities in the MISO region managed FERC and NERC compliance. With MISO, many FERC and NERC compliance responsibilities have been consolidated. As a result, member responsibilities decreased, saving them time and money.

7 **Footprint Diversity - $785-$942 million** MISO's large footprint increases the load diversity factor allowing for a decrease in regional planning reserve margins from 17.40% to 12.06%. This decrease delays the need to construct new capacity.

8 **Generator Availability Improvement - $526-$631 million** MISO's wholesale power market improved power plant availability 3.3%, delaying the need to construct new capacity.

9 **Demand Response - $116-$145 million** MISO enables demand response through dynamic pricing and direct load control and interruptible contracts. MISO-enabled demand response delays the need to construct new capacity.

10 **MISO Cost Structure - $248 million in annual costs** MISO expects administrative costs to remain relatively flat and to represent a small percentage of the benefits.

Qualitative Benefits

In addition to the quantitative benefits, MISO also demonstrates significant qualitative benefits that wholesale market participants receive from the operation of MISO, including:

1. Price/Informational Transparency
2. Planning Coordination
3. Seams Management

Company Facts

MISO ensures reliable operation of and equal access to high-voltage power lines in 11 U.S. states and the Canadian province of Manitoba.

MISO manages one of the world's largest energy markets, clearing more than $27.5 billion in energy transactions in 2010. The non-profit 501(c)(4) organization is governed by an independent Board of Directors, and is headquartered in Carmel, Indiana, with operations centers in Carmel and St. Paul, Minnesota. Membership is voluntary.

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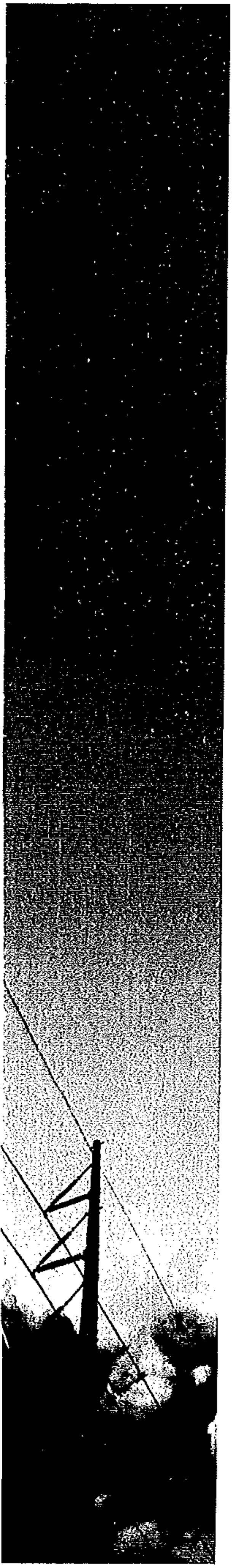


SPP Balanced Portfolio Report

MAINTAINED BY
Engineering/Planning

PUBLISHED: 06/23/2009
CAWG Accepted 06/05/2009
MOPC Accepted 06/12/2009
LATEST REVISION: 06/23/2009

SPP Southwest Power Pool

Schedule SLK-9-1

EXHIBIT 6

TABLE OF CONTENTS

Executive Summary

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. "Balanced" is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio.

After development and review of the Balanced Portfolio, the CAWG endorsed Portfolio 3E "Adjusted" (without Chesapeake, without Reno Co – Summit). Portfolio 3E "Adjusted" provides a significant benefit vs. cost to the SPP region, and would require lower transfer requirements necessary to achieve balance. The CAWG along with the Economics Modeling and Methods Task Force ("EMMTF", now called the Economic Studies Working Group "ESWG") reviewed and approved the study assumptions used in the analysis of the Balanced Portfolio. These assumptions are listed in the appendix. Portfolio 3E "Adjusted" contains a diverse group of 345kV transmission projects addressing many of the top SPP flowgates. The projects associated with Portfolio 3E "Adjusted" are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The CAWG endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15th, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E "Adjusted" pending issuance of the final report, according to SPP Tariff.

Portfolio 3E "Adjusted" provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58.

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Portfolio 3-E "Adjusted"			Million of Dollars Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual	
2012			$ 131.2		$ 93.73	$ 0.03	$ 93.7	
2017			$ 193.2	$ 12.4	$ 93.73	$ 2.53	Total Annual	
2022			$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8	
Year	**8.00% Year #**	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**	
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**	
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53	
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66	
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80	
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93	
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**	
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10	
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20	
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29	
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39	
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**	
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**	
Per Year Levelized				$ 177		$ 95	**1.87**	

The table below outlines the benefits by zones for the 10 year analysis of Portfolio 3E "adjusted".

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

Portfolio 3-E "Adjusted"

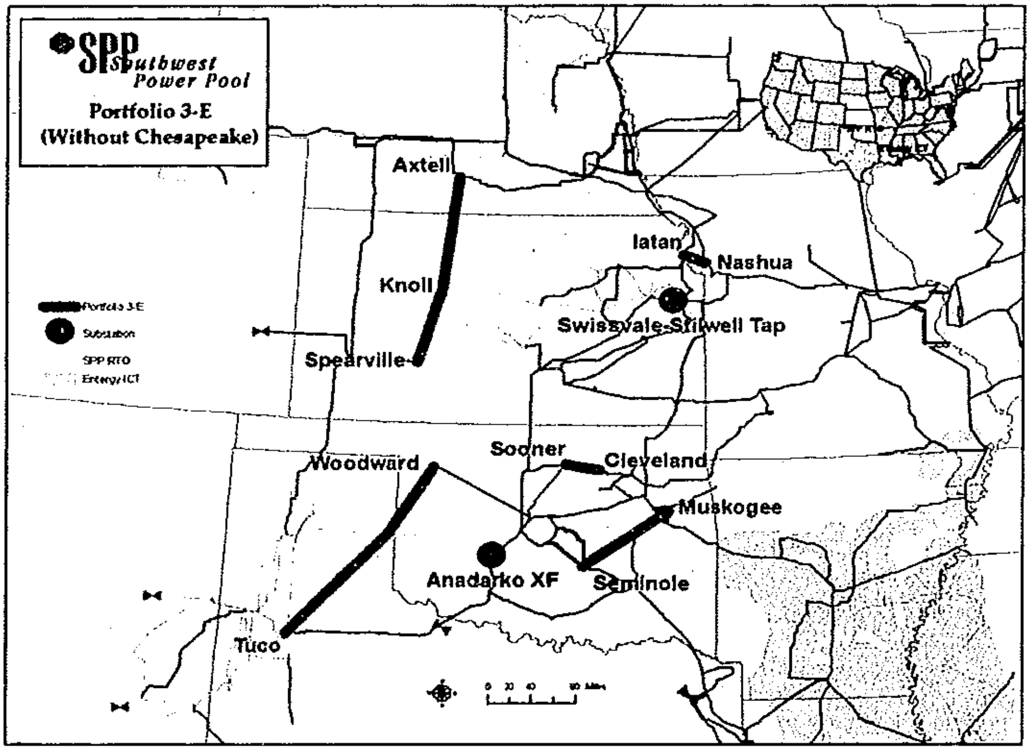


EXHIBIT 6

Introduction

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV* projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e. increasing reliability and lowering reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. "Balanced" is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio†.

Economic Benefits: Adjusted Production Cost

Balanced Portfolio development began with an economic screening of projects identified by stakeholders and SPP staff. After receiving stakeholder feedback, SPP staff compiled a list of economic projects with potential for a positive return.

The first step is to conduct an economic analysis individually on each project considered for the Balanced Portfolio. This process is done by determining the adjusted production cost metric for each project in the screen. Adjusted production cost is defined as:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases

Where:

Revenues from Sales = Export x Zonal $LMP_{\text{Gen Weighted}}$

and

Cost of Purchases = Import x Zonal $LMP_{\text{Load Weighted}}$

Production cost for each unit is based on fuel, variable O&M costs, environmental costs and both scheduled and forced outages‡. Adjusted production cost savings account for the economy purchase and sale of power in the modeling footprint. This is important when benefits are being calculated for zones within the SPP as well as in differentiating overall benefits from the portfolio compared to the benefits accruing to SPP members.

To calculate adjustments to production costs due to an economic transmission project, commercial production cost analysis software is used to estimate hourly unit commitment and dispatch of modeled

* Upgrades of voltages less than 345 kV can be included if needed to deliver the benefits of the extra high voltage (EHV) upgrade, where the cost of the lower voltage facilities does not exceed the cost of the EHV facilities.

† The Tariff allows for deficient zones to be balanced by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual transmission Revenue Requirement from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.

‡ SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages

generators within a context of a modeled transmission system and load delivery points. The commitment and dispatch of the generators is constrained by the software to ensure that no overloads will occur on any monitored transmission element, typically referred to as the NERC book of flowgates, but can include additional congestion points of interest. The software produces a security constrained economic dispatch and unit commitment.

Adjusted Production Cost was the only benefit metric used in the economic analysis. There are other potential benefits which have not been directly quantified such as lowering reserve margins, reducing losses, and providing environmental benefits. For the purpose of this study, these benefit metrics are not used to determine overall portfolio benefits to the region.

Balanced Portfolio Development

The following table provides a timeline for the development of the various candidate portfolios that were developed by the SPP staff and presented during the regularly scheduled CAWG meetings

Table: CAWG Timeline for Balanced Portfolio Development

Months/Year	Key Discussions at CAWG
Aug-Nov 2007	Screening of Candidate Upgrades for Portfolio
Feb –Apr 2008	Initial Portfolios 1, 2, 3 and 4
May 2008	Trapped Generation Issues Discussion Begins
Jun 2008	Spearville-Knoll-Axtell Added to Portfolios 2 and 3
Jul 2008	Portfolios 2 and 3 at 2008 Wind Levels and Turk
Aug 2008	Portfolios 2 and 3: Firm Wind Sensitivities
Sep 2008	Introduction of Portfolios 3-A and 3-B at 345 and 765 kV costs
Oct 2008	Portfolio 3 (high wind) and 3-A (current wind) Analysis
Dec 2008	Portfolio 3-C (modify 3 for high wind)
Jan 2009	Further Analysis of Portfolios 3-A and 3-C with Nebraska
Feb 2009	EMMTF Effort initiated to update and refine economic models
Mar 2009	Final Balanced Portfolio Analysis
Apr 2009	Balanced Portfolio Summit & Balanced Portfolio Recommendation

August-November, 2007: Screening of Candidate Upgrades for Portfolios

Over fifty candidate transmission upgrades for screening were gathered by SPP staff. As agreed by stakeholders, the initial screening analysis was performed based on using only the summer months. A discussion at the CAWG led to additional analyses to include spring-fall months in the calculations of adjusted production cost benefits. The screening analysis was then performed for the summer months and the spring-fall months starting with the spring of March 1, 2012. These estimates of annual benefits were compared to the estimates of engineering and construction (E&C) cost obtained by SPP staff from transmission owners. All projects screened were ranked from highest to lowest according to their benefit-to-cost (B/C) ratios. The SPP staff then used these rankings as a basis for developing a collection of economic upgrades as alternative portfolios[§].

February-April, 2008: Initial Four Portfolios

SPP staff developed four initial portfolios, labeled as Portfolios 1, 2, 3 and 4. Each portfolio had specific criteria for determining which projects to include.

1. Portfolio 1 was a collection of every project from the economic project screening process that had a B/C ratio greater than 1.0.

[§] Note: Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note in the original analysis was the inclusion of Holcomb 2, Red Rock, Hugo 2 as well as 4,600 MW of generic wind capacity which affected the calculated benefits of certain projects.

2. Portfolio 2 was a subset of Portfolio 1 where projects with similar benefits were narrowed to remove upgrades that would not provide additional benefits.

3. Portfolio 3 was assembled with the intent of ensuring each Zone within the SPP region received a project (projects that crossed multiple zones were considered for each zone), with the most beneficial project chosen in each zone.

4. Portfolio 4 was a collection of projects that would be mutually beneficial, thereby raising the overall benefit of the entire portfolio.

These four portfolios, along with their B/C screening ratios, are shown in the following exhibits.

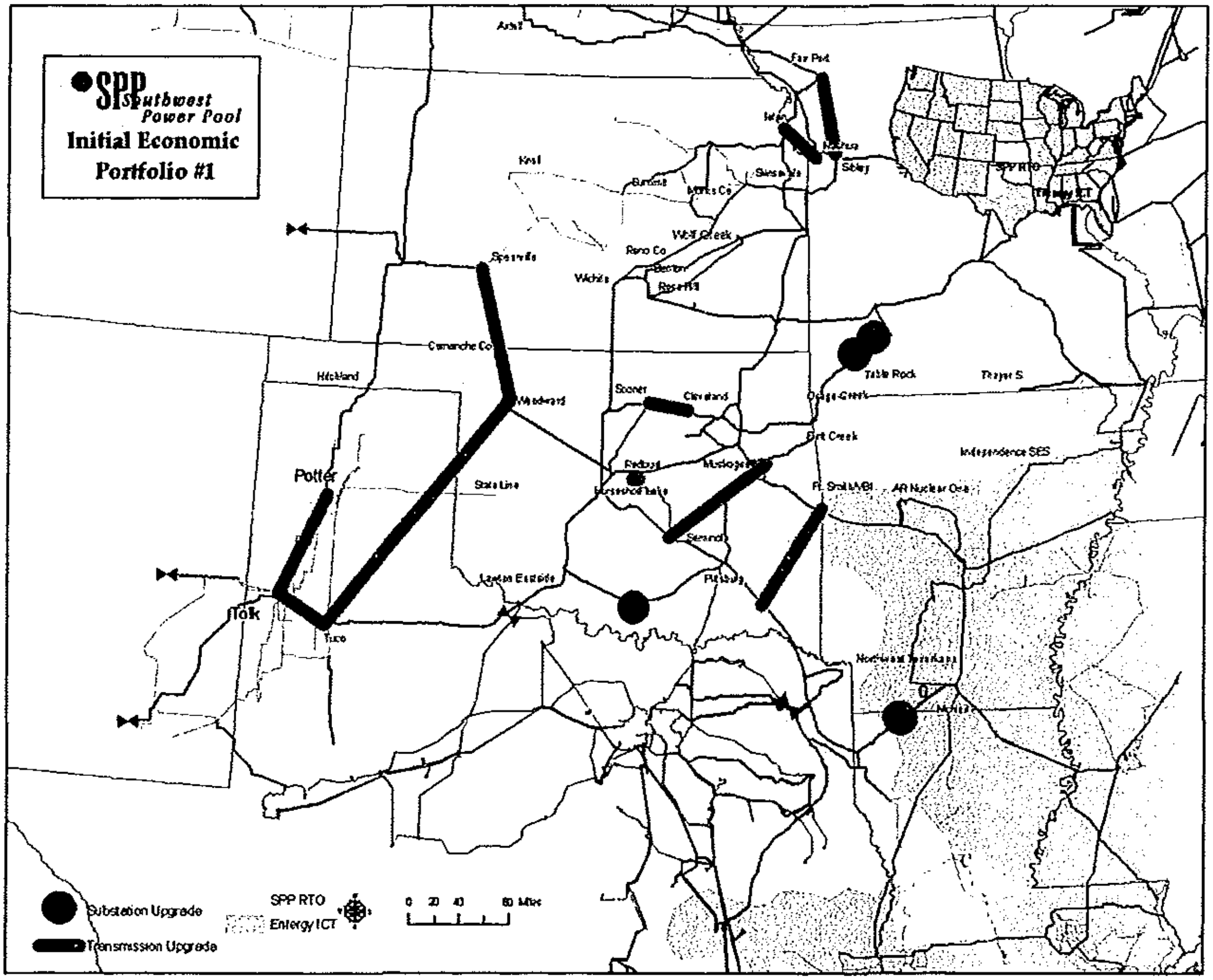
Screening of Proposed Economic Upgrades

[redacted]		P1	P2	P3	P4
Tolk - Potter	7.20			+	
El Dorado - Longwood	3.36	+	+	+	
Iatan - Nashua	2.95	+	+	+	+
SWPS - Battlefield	2.66	+	+		
Chesapeake XF	2.26	+	+	+	
Tuco - Tolk - Potter	1.73	+	+		+
Fairport - Sibley	1.31	+			+
Pittsburg - Ft Smith	1.17	+	+	+	
Spearville-Mooreland/Woodward-Tuco	1.13	+	+	+	+
Seminole - Muskogee	1.08	+			
Monett XF	1.04	+			
Redbud - Horseshoe Lake	1.01	+			
Cleveland - Sooner	0.91	+	+	+	+
Sunnyside XF	0.89	+	+		
Northwest XF	0.89	+	+		+
Swissvale - Stilwell	0.67			+	
Anadarko XF	0.48			+	
Turk - McNeil	0.46				+
Mooreland/Woodward - Wichita	0.14				+
Mooreland/Woodward - Northwest	(0.00)				+

(NOTE: "Tolk – Potter" project is a subset of the "Tuco – Tolk – Potter" project.)

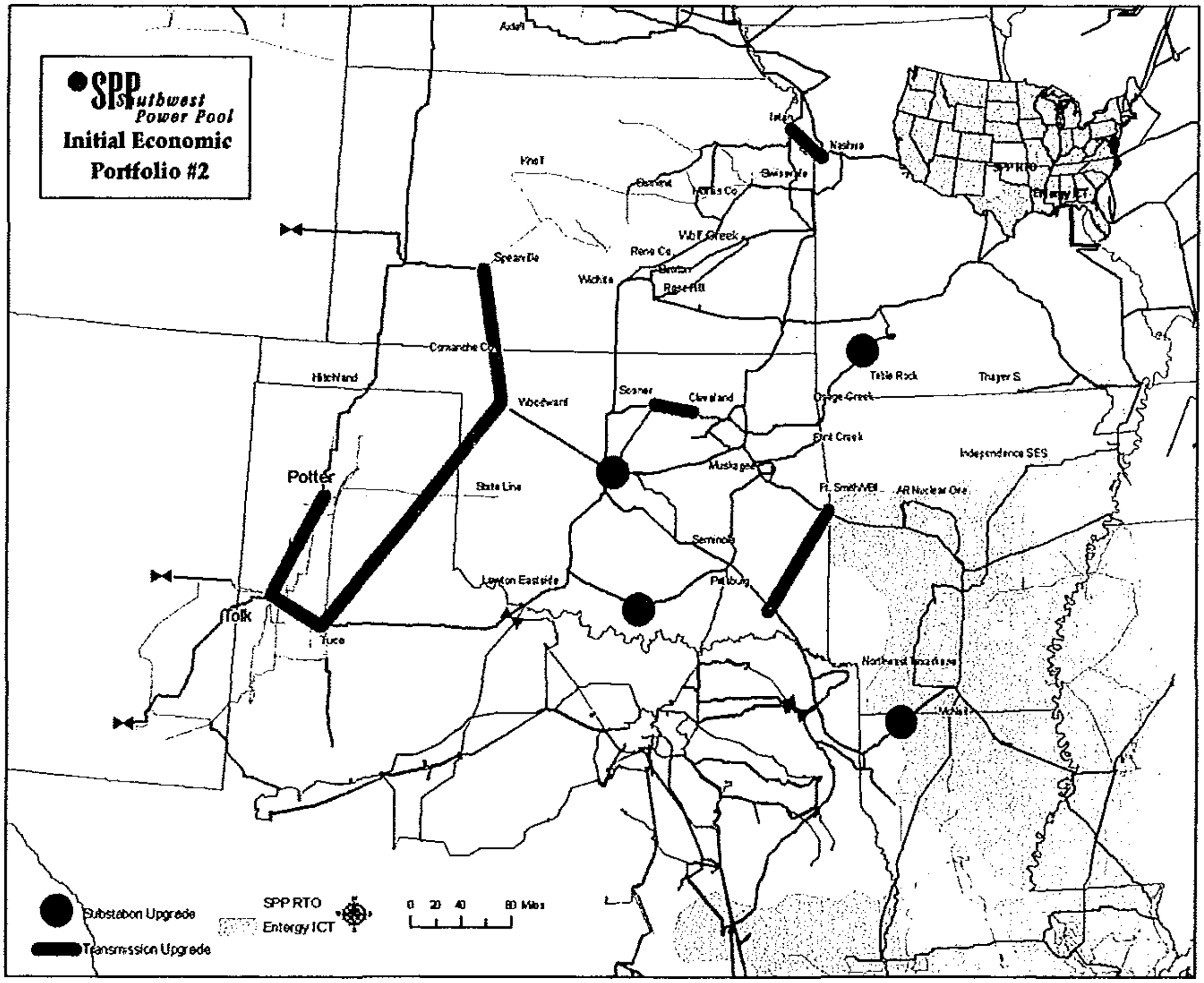
The Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note was the inclusion of Holcomb 2, Red Rock, and Hugo 2 as well as 4,600 MW of generic wind capacity, each of which affected the calculated benefits of certain projects.

Portfolio 1



Because Portfolio 2 eliminated duplicative upgrades from Portfolio 1, Portfolio 1 was not carried forward as a possible Balanced Portfolio candidate.

Portfolio 2



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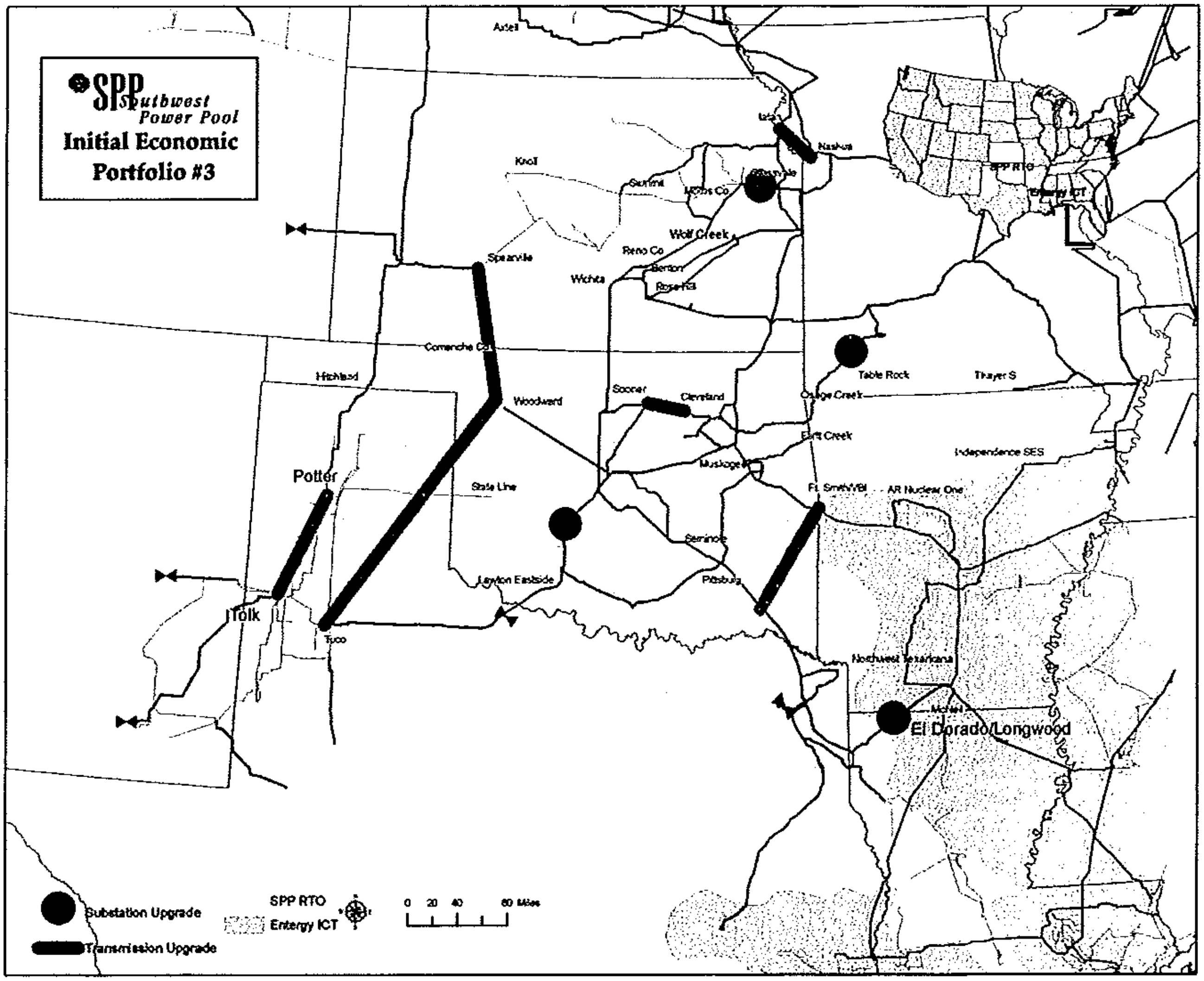
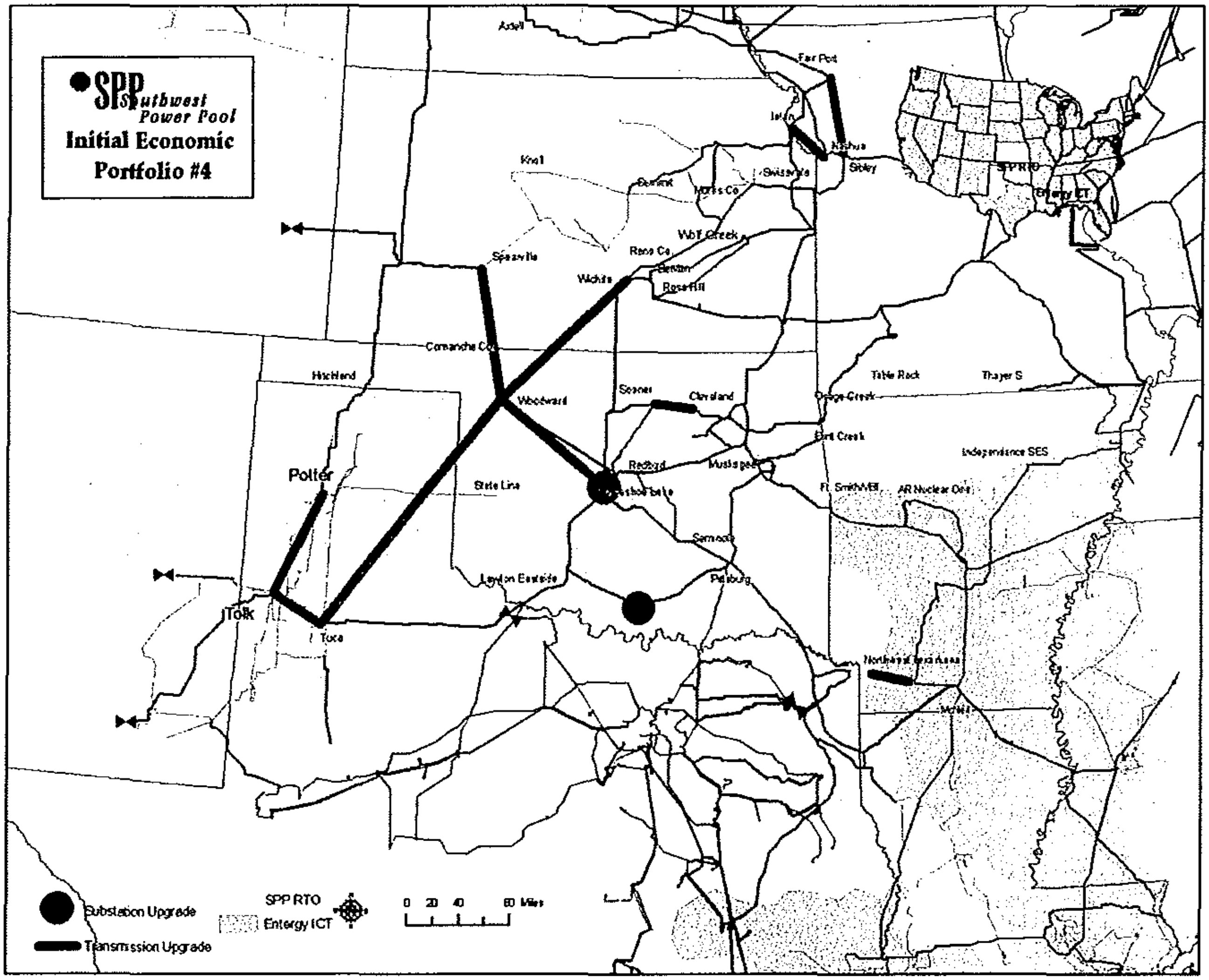
Portfolio 3


Southwest Power Pool
Initial Economic Portfolio #3
Potter
Tolk
El Dorado/Longwood
Substation Upgrade
Transmission Upgrade
SPP RTO
Entergy ICT

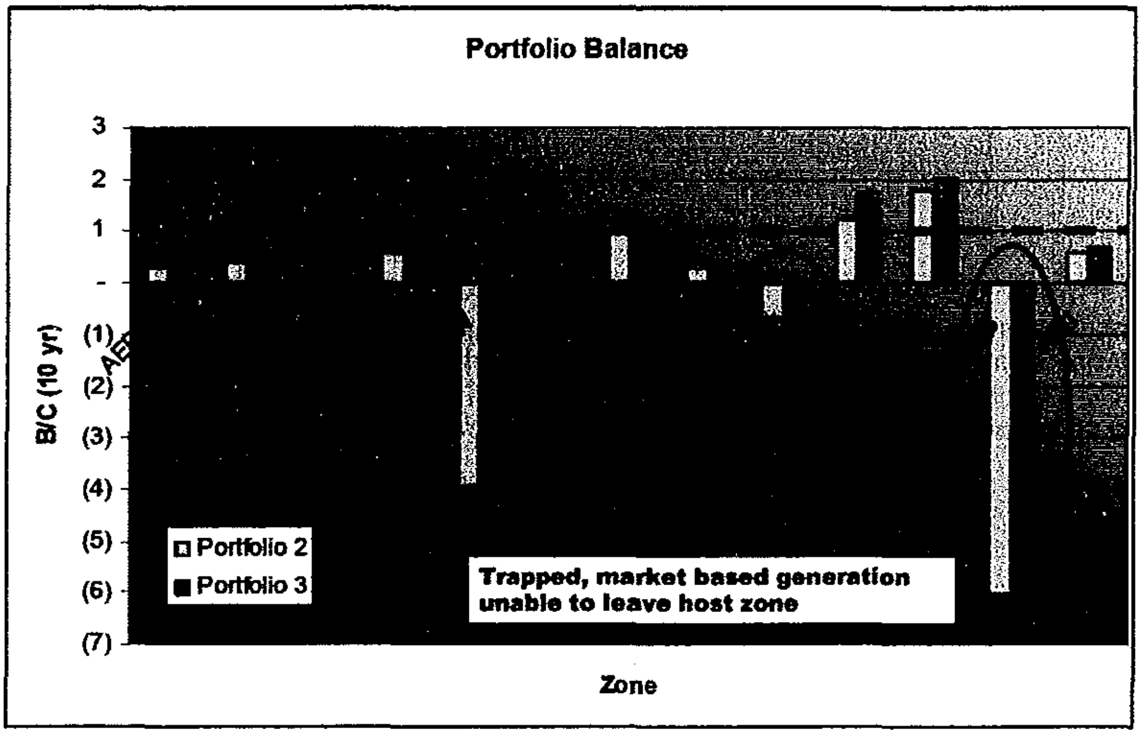
Portfolio 4


Southwest Power Pool
Initial Economic Portfolio #4
Potter
Tolk
Tuco
Woodward
Spearville
Wichita
Comanche Co
Hitchland
State Line
Lawton Eastside
Sooner
Cleveland
Redbud
Muskogee
Seminole
Pittsburg
Wolf Creek
Rose Hill
Benton
Knoll
Iatan
Nashua
Sibley
Fair Port
Table Rock
Thayer S
Flint Creek
Independence SES
AR Nuclear One
Substation Upgrade
Transmission Upgrade
SPP RTO
Entergy ICT
0 20 40 80 Miles

<u>May 2008</u>: Trapped Generation

The CAWG review of the four portfolios, including high wind sensitivities, discovered that the production cost analysis contained significant levels of "trapped generation" (generation that cannot get power out of the host zone due to transmission constraints, significantly impacting the modeling results) related to wind generation. The CAWG initiated the Trapped Generation Task Force (TGTF) to address this issue. The following graph demonstrates effects of trapped generation on portfolio B/C ratios.

Trapped Generation in Economic Models



The TGTF developed guidelines for including generation in the production cost modeling, that were reviewed by the Economic Modeling and Methods Task Force ("EMMTF", now called the Economic Studies Working Group, "ESWG"). The TGTF decided that the base case models should contain wind levels consistent with current wind in service. These models contained 2,600 MW of nameplate wind,** down from 4,600 MW of generic wind included in previous models. Change cases could include additional wind generation, but the TGTF recommended that the additional wind above existing levels must be matched with the transmission upgrades that would be needed to deliver the additional wind to the SPP energy market.

<u>June 2008</u>: Wind and Spearville-Knoll-Axtell (SKA)

SPP staff updated the study models after the TGTF determined that 2,600 MW of wind should be used in the base case. The following table illustrates the resultant B/C ratios for Portfolios 2 through 4, where 2,600 MW of wind is also included in the change case. The adjusted production costs

** This coincides with the amount of wind in the SPP footprint at the end of 2008, as well as the transmission upgrades required to delivery wind with firm service.

shown are changes in adjusted production costs. Therefore, a red parenthetical represents lower adjusted production costs after an upgrade takes place, and it is the estimate of overall benefit.

Preliminary Portfolio Results, post-TGTF (June 26, 2008 CAWG Meeting)

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2 June08	($50,482,000)	($41,409,000)	($9,073,000)	$ 371	0.92
Economic Portfolio - P3_June08	($53,325,000)	($42,060,000)	($11,266,000)	$ 347	1.04
Economic Portfolio - P4_June08	($48,429,000)	($38,581,000)	($9,848,000)	$ 608	0.54

SPP staff conducted a sensitivity analysis of Spearville-Knoll-Axtell on the above portfolios to determine its impact. The Spearville-Knoll-Axtell (SKA) 345kV line is a transmission upgrade for which the Kansas Electric Transmission Authority (KETA) issued a Notice of Intent to Proceed with Construction on July 25, 2007. Additionally, the SPP Board of Directors approved this transmission upgrade for inclusion in the SPP Transmission Expansion Plan (STEP). The SPP Board of Directors requested that all projects of 345 kV and above approved for inclusion in the STEP also be considered candidates in the Balanced Portfolio analyses. It was found in the analyses that the SKA project uniformly raised the B/C ratios of all portfolios, and it appeared that the SKA project should be included for consideration, although a similar analysis was not conducted for other low B/C ratio projects that were not included in the original portfolios. The results are shown in the following table.

Impact of Spearville – Knoll – Axtell

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_SKA_June08	($90,215,000)	($71,327,000)	($18,889,000)	$ 539	1.13
Economic Portfolio - P3_SKA_June08	($92,307,000)	($72,235,000)	($20,072,000)	$ 515	1.22
Economic Portfolio - P4 SKA June08	($84,031,000)	($64,709,000)	($19,322,000)	$ 776	0.73

Because Portfolio 4 had a B/C ratio well below one, it was not included in further analyses in the Balanced Portfolio development process.

<u>July 2008</u>: Update Designated Resources

Portfolios 2 and 3 were updated to include the Turk Plant, a Designated Resource planned to be on line by 2012. This change lowered the benefit to cost ratios below one, as shown in the following table. These results were based on the 2008 wind levels in SPP (2,600 MW) but do not include the Spearville-Knoll-Axtell line.

Impact of Updates on Portfolios 2 and 3

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C	SPP B/C
Portfolio 2 - July 08	($38,291,000)	($28,825,000)	($9,466,000)	$ 371	0.70	0.53
Portfolio 3 - July 08	($42,033,000)	($32,281,000)	($9,751,000)	$ 347	0.82	0.63

<u>August 2008</u>: Firm Wind Sensitivities

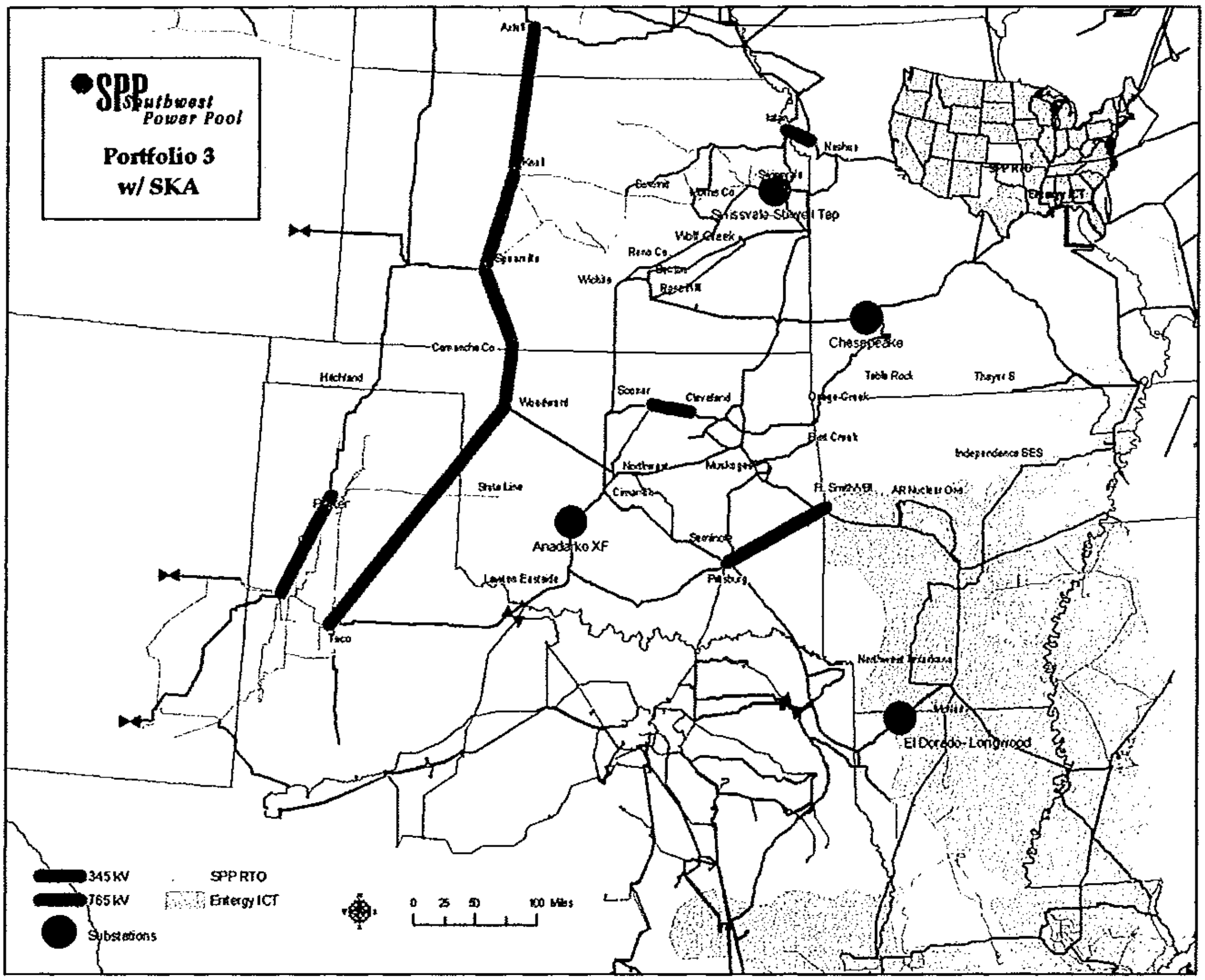
Additional wind sensitivities were conducted for Portfolios 2 and 3 to determine the impact that the amount of wind assumed in the model would have on the benefits. Benefits were estimated for 700 MW of firm wind in the base case and an additional 1,900 MW of market-based wind in the change case. The results showed a significant increase in production cost savings for both Portfolios 2 and 3. The changes in benefits from adding the market-based wind without transmission upgrades were calculated to show the impact of trapped generation. Stakeholders supported the inclusion of all existing wind in the portfolios even though wind without firm transmission service would lower the B/C ratios.

<u>September 2008</u>: Introduction of Portfolio Variations 3-A and 3-B

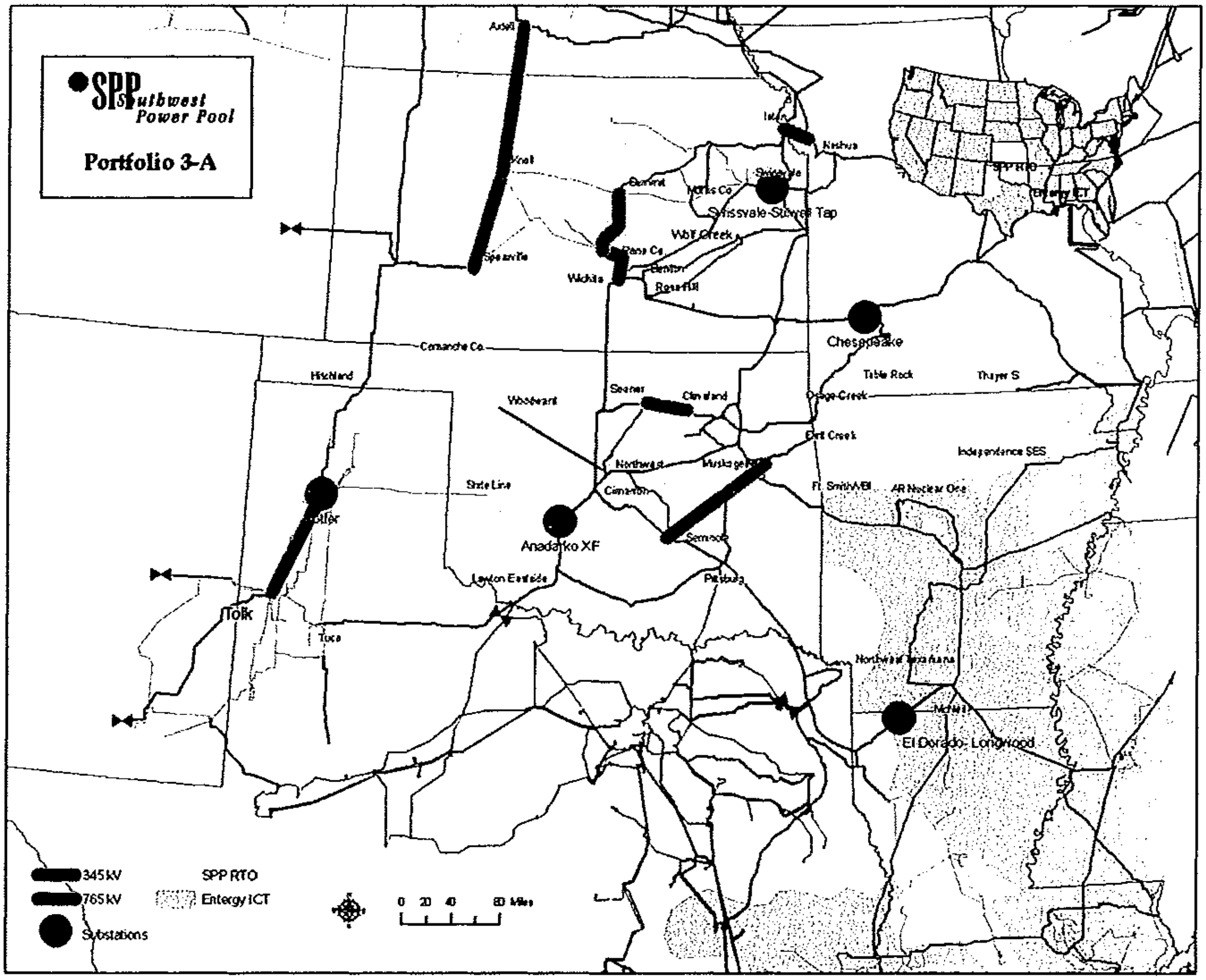
SPP staff developed two modified portfolios based on Portfolio 3. Adjustments to Portfolio 3 included an upgrade of the Wichita – Reno Co - Summit line and carried through the addition of Spearville-Knoll-Axtell. From this modification of Portfolio 3 two variations were developed and labeled 3-A and 3-B. These portfolios are shown pictorially below.

Since many sections of Portfolio 3 included transmission paths that are also in the proposed EHV Overlay Plan, the CAWG decided to consider these common corridor projects for 765 kV construction in the balanced portfolio. The purple lines in the following maps illustrate this construction.

Portfolio 3, with Spearville – Knoll – Axtell (SKA)



Portfolio 3-A with Wichita - Reno Co - Summit



Schedule SLK-9-18

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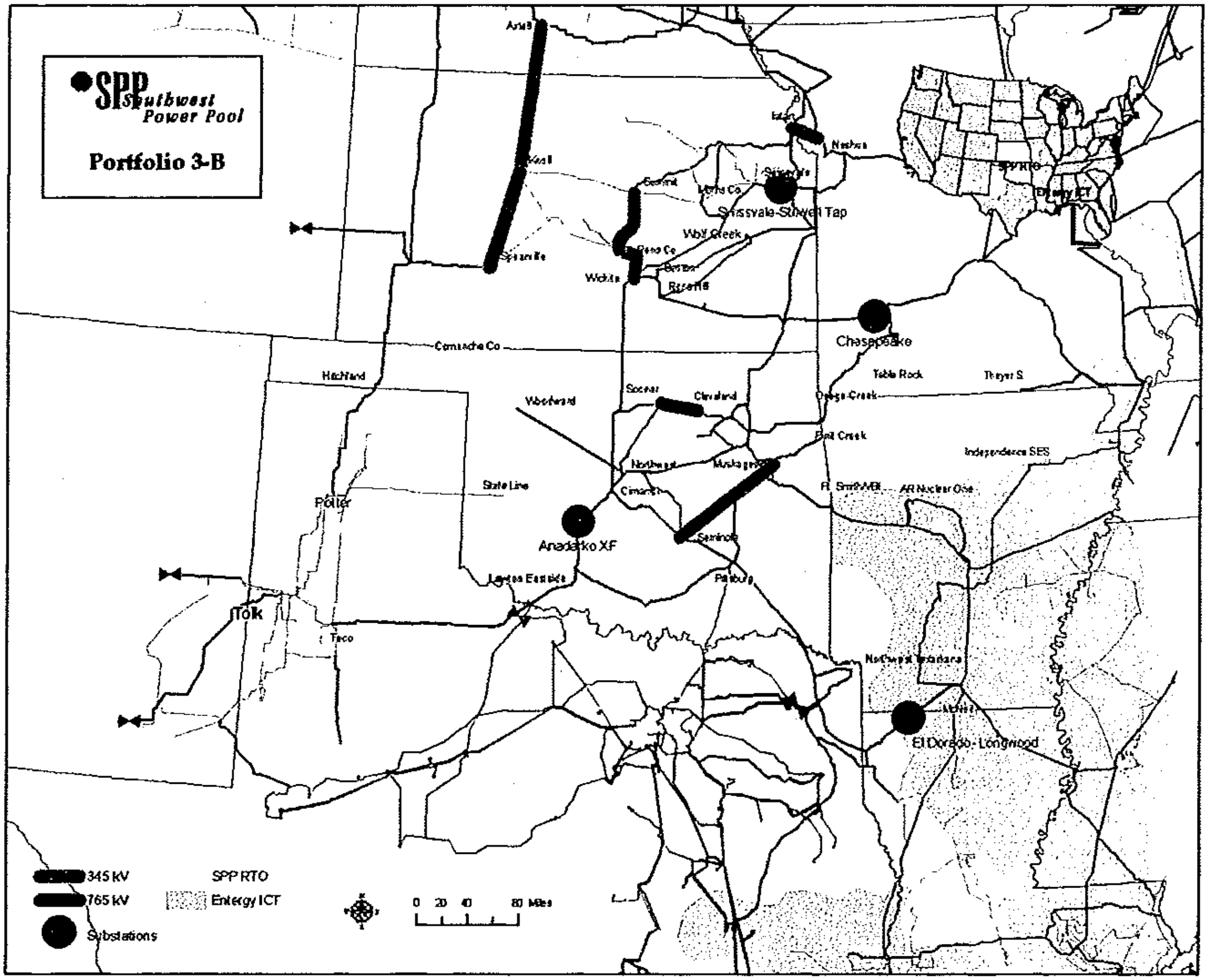
Portfolio 3-B with Wichita – Reno Co - Summit



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Modeling assumptions for the dispatch of wind were still an issue in these results where SPP staff used a wind offer price of $20/MWh. Given this caveat, the results showed that both Portfolios 3-A and 3-B had B/C ratios greater than one using 345 kV costs, but were marginal when 765 kV costs were used in the calculations. Portfolio 3-B is a sensitivity of Portfolio 3-A used to test whether or not the Tolk-Potter upgrades would increase the B/C ratio. Since they did, the SPP staff recommended going forward with Portfolio 3-A, as well as subsequent consideration of additional variations of Portfolio 3.

Initial Results for Portfolios 3-A and 3-B

Project	Cost ($M)	Proj 10 Year SPP Benefit ($M)	SPP B/C
345 kV Construction			
Portfolio 3-A	$585	$776	1.33
Portfolio 3-B	$545	$693	1.27
765 kV Construction			
Portfolio 3-A	$761	$776	1.02
Portfolio 3-B	$721	$693	0.96

<u>October 2008</u>: Portfolio 3 (High Wind) and 3-A (Current Wind)

Two different types of analyses were considered for Portfolios 3 and 3-A. Since Portfolio 3 has upgrades similar to those on the western portion of the proposed EHV system, the SPP staff evaluated Portfolio 3 using a high wind (7 GW) scenario with specific wind locations for wind capacity above the current 2008 level of 2.6 GWs. In particular, the B/C ratio was calculated for both 345 kV and 765 kV costs to get a feel for whether or not Portfolio 3 could support a portion of the EHV upgrades in the western SPP region.

High Wind (7 GW) for Portfolio 3

Scenario	SPP 10 Yr Benefit	Cost ($M)	B/C
Portfolio 3 - 345 kV	$ 1,920,593,438	829	2.32
Portfolio 3 - 765 kV*	$ 1,920,593,438	1,213	1.58

SPP staff used Portfolio 3-A to test the sensitivity of a carbon tax on the estimate of benefits from savings in the adjusted production costs. The results indicated that keeping wind at its current levels and imposing a carbon tax would, as expected, result in a significant decrease in benefits for Portfolio 3-A.

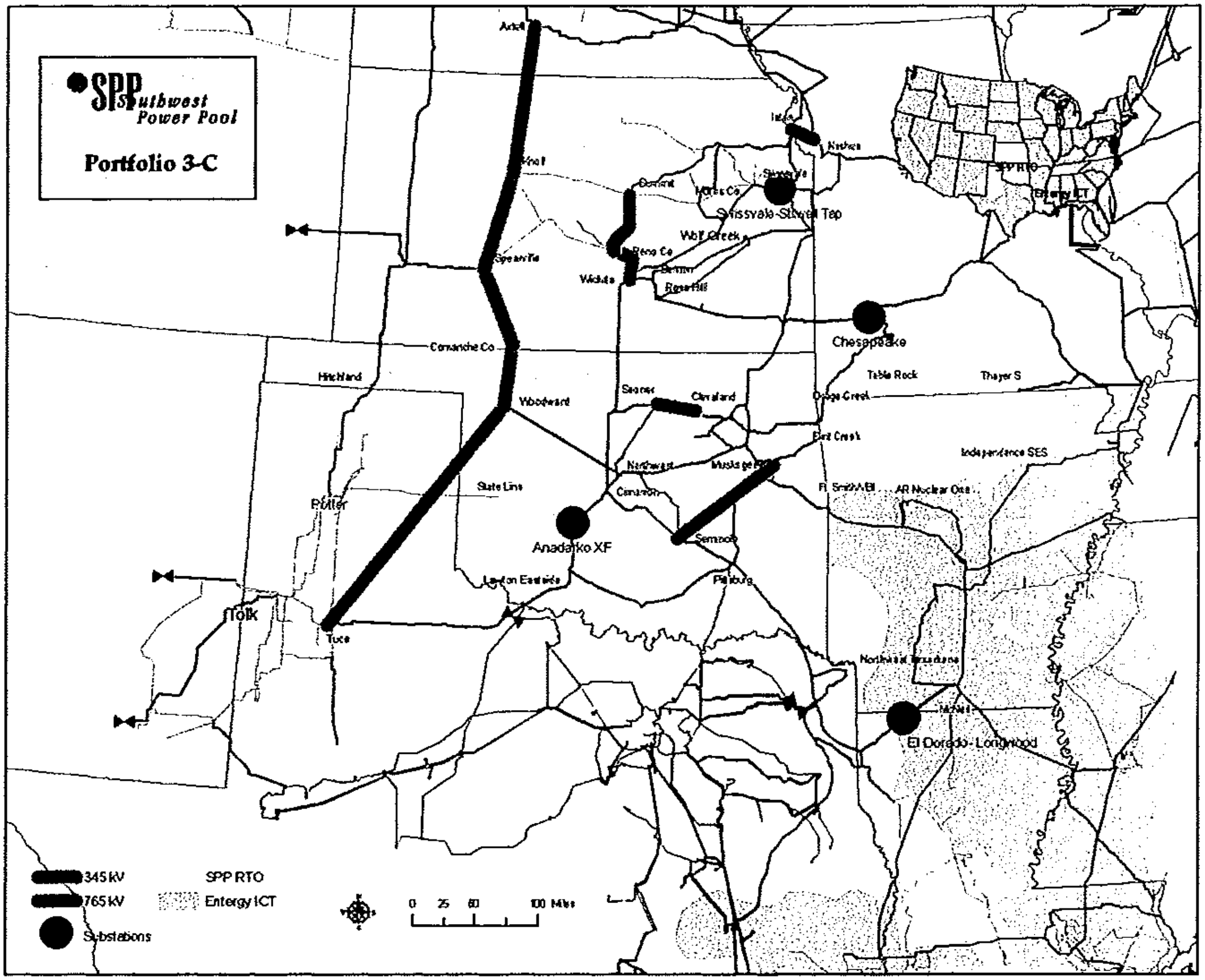
Carbon Tax Sensitivity Results for Portfolio 3-A at Current Wind (2.6 GW)

Project	Total Adjusted Production Cost	SPP NON-OATT	SPP OATT	Non-SPP	Cost	SPP B/C
Portfolio - P3A - Base	($119,180,000)	($2,454,920)	($111,931,080)	($4,794,000)	$ 597	1.27
Portfolio - P3A - $15 Carbon Tax	($60,140,000)	($4,000)	($52,699,000)	($5,543,000)	$ 597	0.60
Portfolio - P3A - $40 Carbon Tax	($17,992,000)	($317,000)	($16,926,000)	($1,630,000)	$ 597	0.19

<u>December 2008</u>: Portfolio 3-C (Modify Portfolio 3)

Portfolio 3-C was developed as a hybrid of Portfolios 3 and 3-A by removing the Tolk - Potter upgrades but adding the Spearville – Knoll - Axtell and Wichita – Reno Co - Summit lines. The following graph pictorially represents Portfolio 3-C.

Portfolio 3-C



It should be noted that by this time SPP staff had resolved a problem with its application of the PROMOD that had resulted in dispatching wind on a small number of days, resulting in what appeared to be a significant "trapped generation" problem. With the resolution of that issue, wind was now being dispatched from specified injection points at $0.05/MWh. Note that this was an offer price for the wind injection into the market since using an offer price of $0/MWh which caused problems in the modeling. The final clearing price of wind is at the marginal zonal market price for each hour, which is significantly higher than the offer price; i.e. wind in the actual production cost models is priced at the marginal zonal market price.

SPP staff used Portfolio 3-C to perform an analysis of an integration plan for the EHV Overlay. For this effort, scenarios were conducted at 3,300 MW of wind injection in 2012, 7,000 MW of wind injection in 2017, and 13,500 MW of wind injection in 2023, with 765 kV transmission being added to the analysis to accommodate the higher wind levels assumed for wind. The following table shows the B/C ratio that would apply had the results of year 2012 been distributed uniformly over a ten-year period and compared to the ten-year cost. In addition, the results are shown using ten years of Annual Transmission Revenue Requirements (ATRR) for the EHV projects contained in the study periods 2012, 2017 and 2023.

Portfolio 3-C + EHV Build Out		
Benefit : Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C (P3-C)	0.74	0.66
10 yr vs E&C (P3-C+West EHV)	0.79	0.72
10 yr vs E&C (P-3C+West & Central EHV)	2.43	1.45
10 yr vs ATRR	0.71	**0.49**
Annual B/C (final year)	1.99	1.19

SPP staff reran portfolio 3-A at 3,300 MW of wind to determine the impact of adding 700 MW of market-based wind to the benefits of this portfolio. The following table gives the results for Portfolio 3-A using 765 kV costs.

Portfolio 3-A		
Benefit : Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C	1.46	1.30
10 yr vs ATRR	**1.19**	**1.06**
Annual B/C (final year)	1.46	1.29

In addition to the adjusted production cost and cost benefit analysis, SPP Staff analyzed the impacts of the portfolio options on basic reliability. Portfolios 3-C and 3-A were considered in this analysis. The results of the total Engineering and Construction (E&C) cost impacts on regional reliability are shown in the table below with 3-C yielding the greatest benefits by reducing reliability needs to a net amount of $31M. More detailed impacts are shown in Appendix D.

P3-A and 3-C impact on STEP reliability assessment

Project	New Violations	Solved Violations	Net
Portfolio 3-A	$4,385,000	$4,004,900	**-$380,100**
Portfolio 3-C	$4,585,000	$35,265,250	**$30,680,250**

<u>January 2009</u>: Further Analysis of Portfolios 3-A and 3-C With Nebraska

At the December 2008 CAWG meeting, further analysis of Portfolios 3-A and 3-C was requested, including the addition of the three pricing zones in Nebraska as a result of the Nebraska entities decision to join the Southwest Power Pool. The emphasis on Portfolio 3-A was in regard to the balance of this portfolio when the Nebraska zones were added, and to compare this balance when Portfolio 3-A upgrades are priced at 345 kV versus 765 kV costs. With the addition of Nebraska, the B/C ratio for Portfolio 3-A at 765 kV increased from 1.06 to 1.11, and at 345 kV from 1.27 to 1.50. The higher costs at 765 kV resulted in significant levels of cost transfers needed to balance the portfolio compared to the lower costs at 345 kV.

Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

#	Zone	Benefits	Costs	Transfer Allocation	Transfer Out	Transfer Net	Net Benefit	B/C	Original B/C
1	AEPW	$20,880,672	$24,939,597	$14,640,350	-$18,699,275	-$4,058,925	$0	1.00	0.84
2	EMDE	$5,828,820	$2,923,755	$1,716,339	$0	$1,716,339	$1,188,726	1.26	1.99
3	GRDA	$1,797,527	$2,170,293	$1,274,032	-$1,646,798	-$372,766	$0	1.00	0.83
4	KCPL	$8,337,354	$8,571,771	$5,031,907	-$5,266,324	-$234,417	$0	1.00	0.97
5	MIDW	$1,590,879	$798,241	$468,593	$0	$468,593	$324,045	1.26	1.99
6	MIPU	$1,598,074	$4,491,010	$2,636,368	-$5,529,303	-$2,892,935	$0	1.00	0.36
7	MKEC	$5,294,897	$1,243,893	$730,206	$0	$730,206	$3,320,798	2.68	4.26
8	OKGE	$44,982,968	$15,731,003	$9,234,607	$0	$9,234,607	$20,017,358	1.80	2.86
9	SPRM	-$29,773	$1,719,556	$1,009,435	-$2,758,764	-$1,749,329	$0	1.00	-0.02
10	SUNC	$389,069	$1,185,151	$695,722	-$1,491,804	-$796,082	$0	1.00	0.33
11	SWPS	$43,102,775	$12,809,661	$7,519,685	$0	$7,519,685	$22,773,429	2.12	3.36
12	WEFA	$11,792,345	$3,508,023	$2,059,323	$0	$2,059,323	$6,224,999	2.12	3.36
13	WRI	$23,072,688	$12,818,241	$7,524,722	$0	$7,524,722	$2,729,725	1.13	1.80
14	NPPD	-$608,956	$8,896,109	$5,222,303	-$14,727,368	-$9,505,065	$0	1.00	-0.07
15	OPPD	-$472,047	$6,896,029	$4,048,192	-$11,416,267	-$7,368,075	$0	1.00	-0.07
16	LES	-$145,808	$2,130,072	$1,250,421	-$3,526,301	-$2,275,880	$0	1.00	-0.07
Total		**$167,411,485**	**$110,632,404**	**$65,062,205**	**-$65,062,205**	**$0**	**$56,579,080**	**1.51**	**1.51**

All numbers in the above table represent annualized costs for Portfolio 3-A over a ten-year period.

Transfers out of a zone represent the dollars that must be moved from the zonal rates to a region-wide rate in order to achieve balance. Two measures of the degree of balance of a portfolio include: a) the number of zones with positive net benefits after the transfers (in this case: 7 of 16 total zones); and b) the ratio of the transfers out to the costs of the upgrades (in this case: 58.7%).

Additional analysis of the EHV upgrades in Portfolio 3-C were performed with and without Portfolio 3-A to determine whether or not portfolio 3-A added more benefits than costs to a zone that would include parts of the EHV (765 kV) overlay. The results indicated that Portfolio 3-A did add more benefits than costs.

Analysis of Portfolio 3-C showed a B/C ratio of 0.58 using 765kV costs and a ratio of 0.94 using 345 kV costs.

CAWG Response

Due to the difficulty in balancing a portfolio that includes 765 kV projects, as well the high level of uncertainty concerning the level of wind available to the SPP footprint on the planning horizon, it was decided in February 2009 that the Balanced Portfolio should include only existing wind generation in service or under construction. The CAWG directed SPP staff to update the economic models to reflect these changes and to work through the EMMTF to ensure that the models were vetted through the stakeholder process to ensure that all member data was represented accurately. Additionally, the CAWG requested that the Nebraska modeling parameters be updated to include a better, more expansive representation for utilities beyond Nebraska to better account for the economic interchange of energy beyond the Nebraska zones. Lastly, the CAWG requested that SPP Staff work with the EMMTF to update all costs associated with the construction of portfolio projects. The E&C costs had shown a significant degree of variability throughout the course of the Balanced Portfolio effort to date due to changes in the economic climate, leading the CAWG to seek an accurate, updated account of these associated construction costs from each respective constructing member.

SPP Staff Action Plan

SPP staff, in response to the CAWG, developed an action plan to address the issues raised and also developed a timeline for the completion of the Balanced Portfolio analysis that would conclude with a staff recommendation in April 2009. This action plan detailed how SPP staff would work with the EMMTF to address any outstanding modeling and cost issues for the simulation of the Balanced Portfolio. Additionally, the action plan, corresponding to the suggestion by the CAWG, defined that the analysis would consider only existing wind resources. SPP staff worked with stakeholders to determine the exact levels of existing wind resources on the system in the process of facilitating the modeling refinements through the EMMTF. Also, as the RSC directed, Portfolios 3, 3-A and 3-C were used as a starting point for these additional analyses. Lastly, Portfolio 3-D (shown below) was developed and included in the analysis. This action plan was presented to the CAWG at the end of January 2009.

Portfolio 3-D

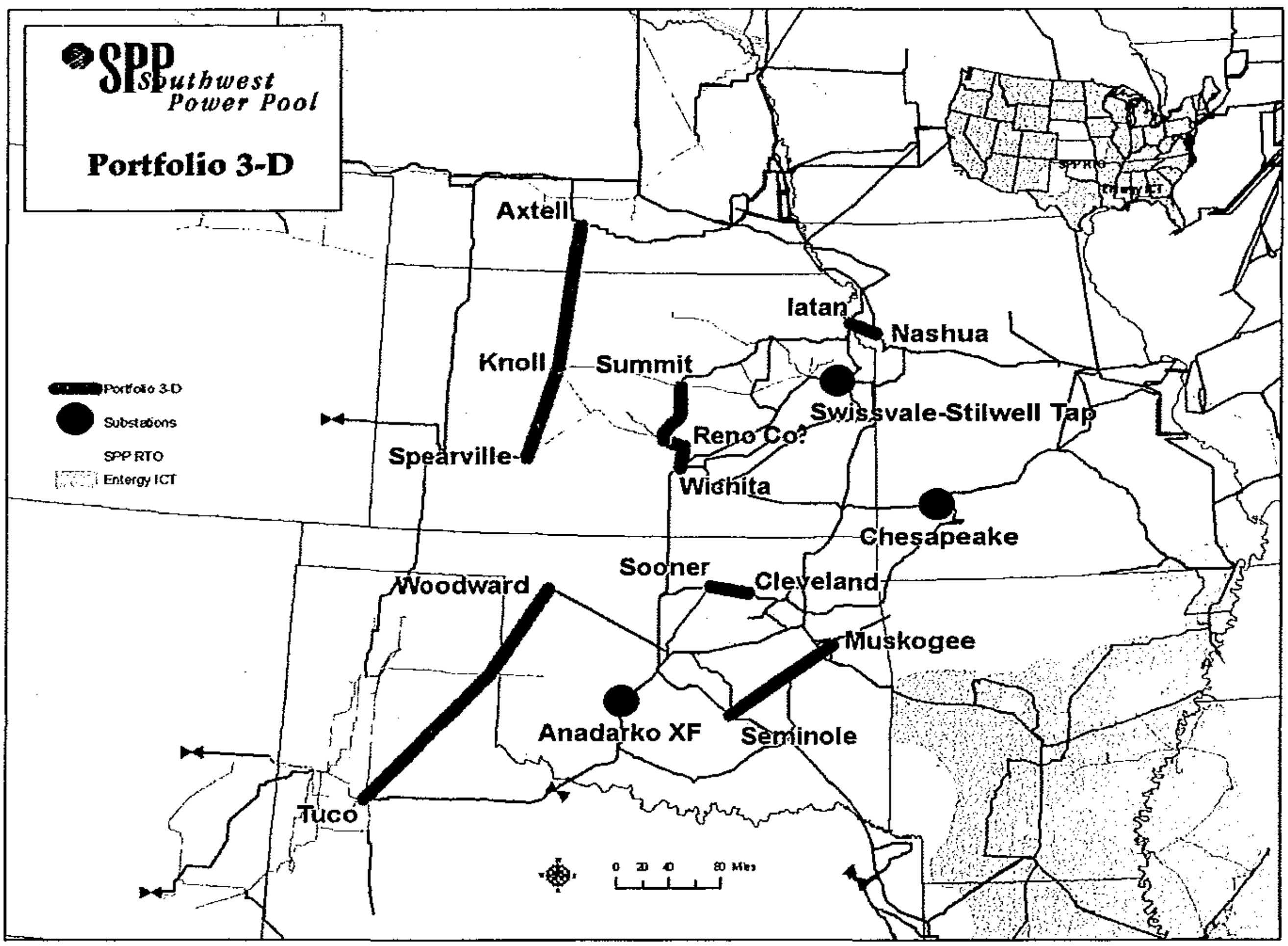


EXHIBIT 6

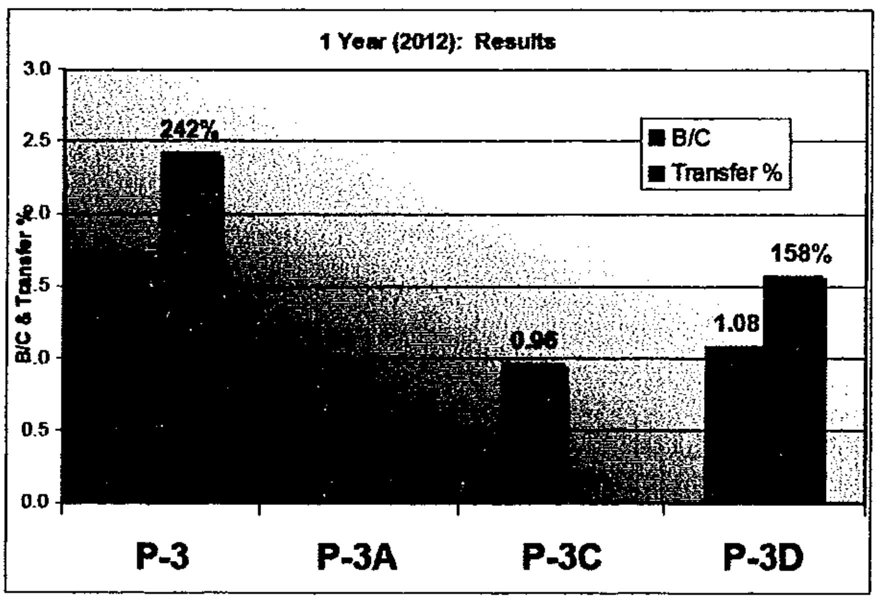
March 2009: Final Balanced Portfolio Analysis

Further material pertaining to the Balanced Portfolio was not presented until the March 2009 CAWG meeting. staff and stakeholders spent the majority of February working through the EMMTF on updating process and refining the engineering models used for the analysis. Additionally, the EMMTF members reviewed their respective output data and provided feedback to SPP staff. The data was checked for the reasonableness of the output results as well as the accuracy of the input into the production cost modeling. These changes were included in the Balanced Portfolio analysis.

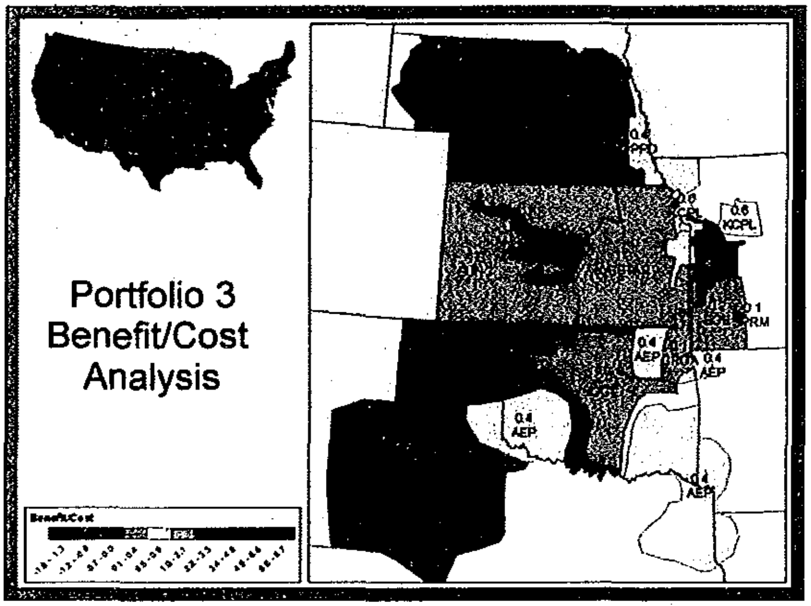
During the March 2009 CAWG meeting, the results from the analysis described above were presented. SPP staff started with a screening analysis on Portfolios 3, 3-A, 3-C, and 3-D. This analysis was conducted on the 2012 model and taken as an annual benefit to cost basis. The results are shown in the following exhibits.

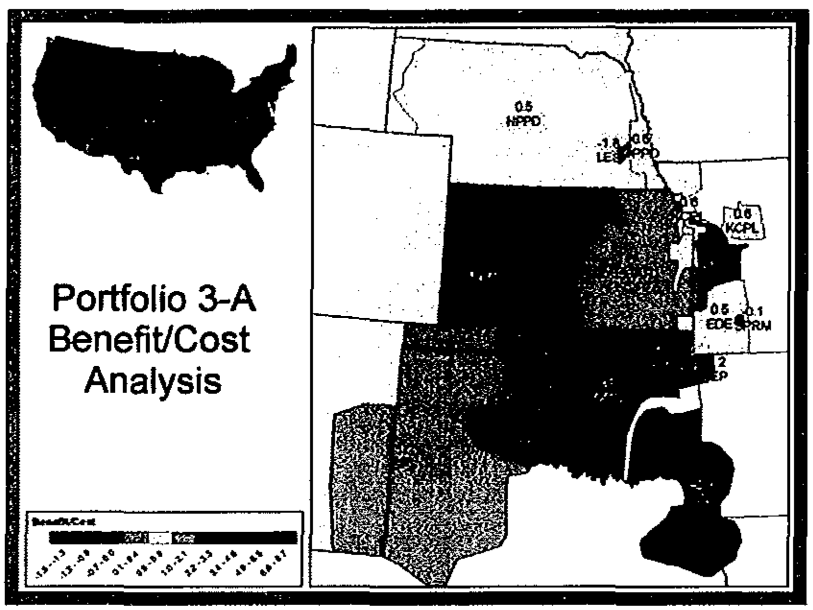
1 Year (2012) Screening Results

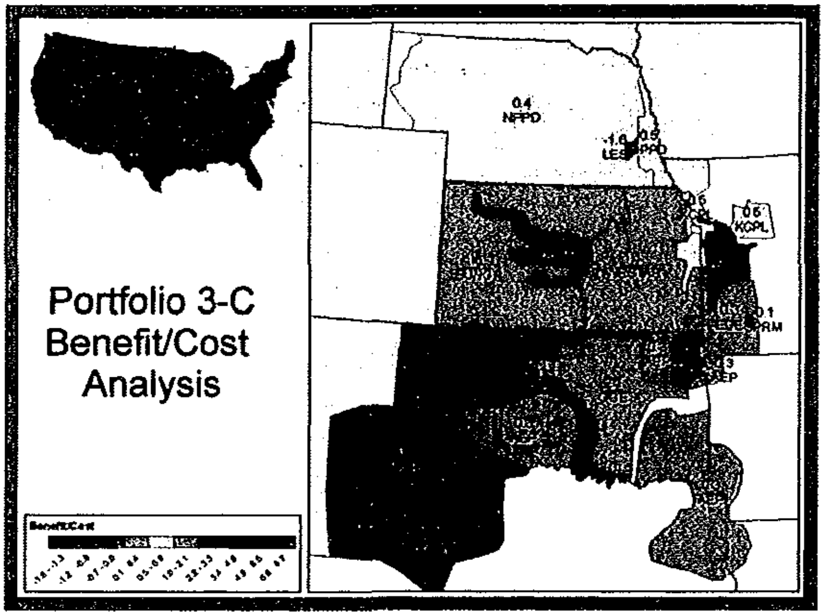
Project	Total APC Benefit ($M)	SPP OATT Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3	$124	$122	$2.6	$ 120	1.02	242%
P-3A	$117	$114	$2.7	$ 121	0.94	n/a
P-3C	$159	$159	($0.4)	$ 166	0.96	n/a
P-3D	$148	$149	($1.3)	$ 139	1.08	158%

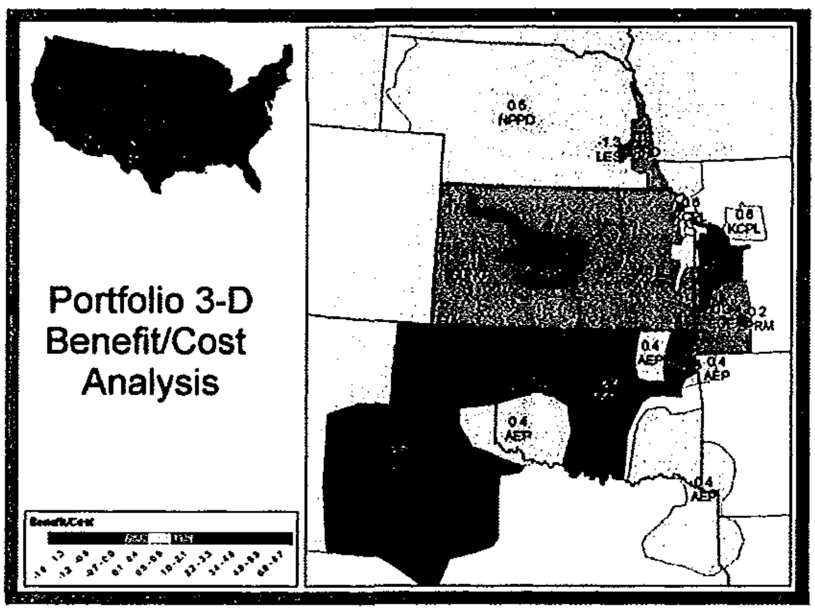


The Benefit to Cost ratio per zone is shown for the respective portfolios in the following pictures. The B/Cs shown here are before transfers have been conducted to balance the respective portfolios.









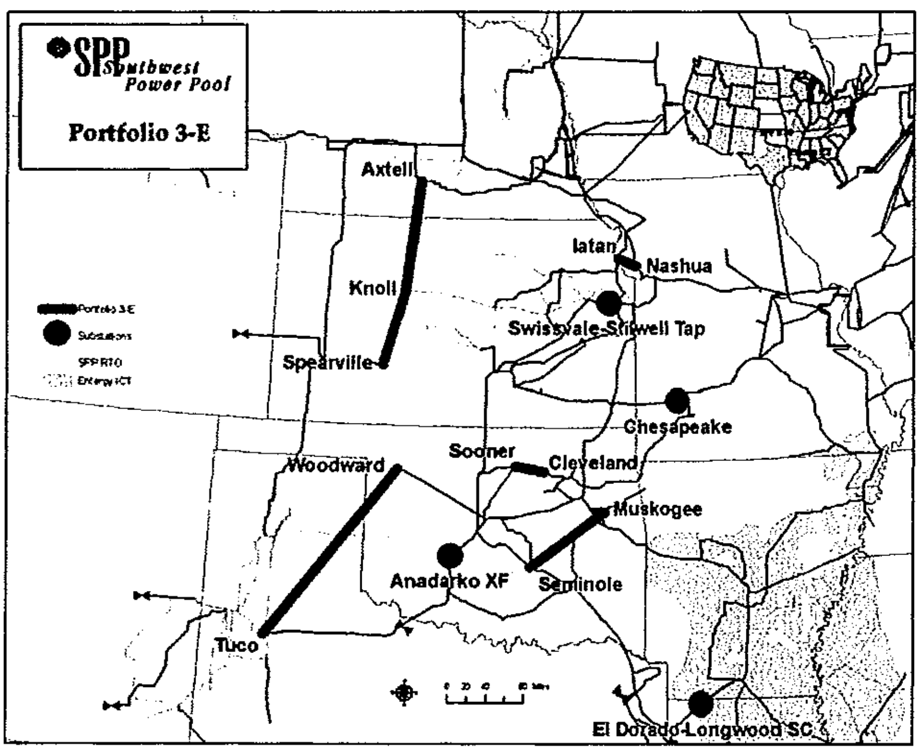
Portfolio 3-D had the highest B/C ratio of the four portfolios screened and was selected for further development. In this analysis, each of the individual projects in the Portfolio was removed to determine the impact of the project on the portfolio as a whole. These results are shown in the following table. The table is divided into total Adjusted Production Cost (APC) benefit, benefit for SPP Open Access Transmission Tariff (OATT) members as well as benefits to areas outside the region, shown here as Tier 1 benefits. The transfer percentage (%) shown is the percentage of the total portfolio cost in dollars that must be transferred, following tariff provisions, to balance the respective portfolios shown below. Ideally, the goal is a lower transfer percentage is desirable with a higher B/C.

Portfolio 3-D Refinement Analysis

Project	Total APC Benefit ($M)	SPP Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3D	$148	$149	($1.3)	*$ 139*	1.08	158%
Portfolio 3D sensitivities						
no WRS (P-3E)	**$137**	**$132**	**$4.3**	**$ 107**	**1.24**	121%
no SKA	**$127**	**$128**	**($0.8)**	**$ 114**	**1.12**	111%
no TW	$121	$116	($1 1)	$ 105	**1.10**	**324%**
no Ches	$146	$148	($1 4)	$ 136	**1.09**	**156%**
no SM	$116	$122	($6.6)	$ 115	**1.06**	**183%**
no IN	$143	$142	$0.5	$ 132	**1.08**	**168%**
no WGard	$152	$149	($1.6)	$ 138	**1.08**	**160%**
no ADK	$146	$147	($0.9)	$ 137	**1.07**	**159%**
no SC	$120	$122	($1.2)	$ 135	**0.90**	**n/a**

The projects that were the best candidates for removal from Portfolio 3-D were (1) Wichita – Reno Co. – Summit, (2) Spearville – Knoll – Axtell and (3) the Chesapeake Transformer. SPP staff recommended during the March 2009 CAWG meeting that the Wichita – Reno Co. – Summit line be removed from the portfolio, but also recommended Spearville – Knoll – Axtell and Chesapeake stay in the portfolio to maintain balance. This Portfolio was labeled Portfolio 3-E and is shown in the following map.

Portfolio 3-E



Portfolio 3-D and 3-E were selected as the candidates for the full 10-year analysis of portfolios as required by the Tariff. The following tables demonstrate the results of the 10-year analysis, with interpolation between simulated years, 2012, 2017 and 2022. The results are discounted back to present worth, using an 8% discount rate. Levelized annual values were also calculated. The annual cost of the each portfolio is given such that the host utility carrying charge rate is assumed to be used for the construction of the project.

Portfolio 3-D: 10 Year Benefit vs. Costs

Portfolio 3-D	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
		Million of Dollars			
2012	$ 149.0		$ 138.55		826.4
2017	$ 208.5	$ 11.904	$ 138.55	$ -	**Annual**
2022	$ 260.3	$ 10.364	$ 138.55	$ -	138.5

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 149	$ 149	$ 139	$ 139	**1.08**
2013	2	0.93	$ 161	$ 149	$ 139	$ 128	1.16
2014	3	0.86	$ 173	$ 148	$ 139	$ 119	1.25
2015	4	0.79	$ 185	$ 147	$ 139	$ 110	1.33
2016	5	0.74	$ 197	$ 145	$ 139	$ 102	1.42
2017	6	0.68	$ 209	$ 142	$ 139	$ 94	**1.50**
2018	7	0.63	$ 219	$ 138	$ 139	$ 87	1.58
2019	8	0.58	$ 229	$ 134	$ 139	$ 81	1.65
2020	9	0.54	$ 240	$ 129	$ 139	$ 75	1.73
2021	10	0.50	$ 250	$ 125	$ 139	$ 69	1.80
2022	11	0.46	$ 260	$ 121	$ 139	$ 64	**1.88**
Ten Year Totals	Yrs 1-10	7.25	$ 2,010	$ 1,405	$ 1,385	$ 1,004	**1.40**
Per Year Levelized				**$ 194**		**$ 139**	**1.40**

Portfolio 3-DE: 10 Year Benefit vs. Costs

Portfolio 3-E	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
	Million of Dollars				
2012	$ 132.3		$ 106.63		657 4
2017	$ 181.2	$ 9.786	$ 106.63	$ -	Annual
2022	$ 229.5	$ 9.652	$ 106.63	$ -	106.6

Year		8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
	2012	1	1.00	$ 132	$ 132	$ 107	$ 107	**1.24**
	2013	2	0.93	$ 144	$ 133	$ 107	$ 99	1.35
	2014	3	0.86	$ 156	$ 134	$ 107	$ 91	1.46
	2015	4	0.79	$ 168	$ 133	$ 107	$ 85	1.58
	2016	5	0.74	$ 180	$ 132	$ 107	$ 78	1.69
	2017	6	0.68	$ 181	$ 123	$ 107	$ 73	**1.70**
	2018	7	0.63	$ 192	$ 121	$ 107	$ 67	1.80
	2019	8	0.58	$ 202	$ 118	$ 107	$ 62	1.89
	2020	9	0.54	$ 212	$ 115	$ 107	$ 58	1.99
	2021	10	0.50	$ 223	$ 111	$ 107	$ 53	2.09
	2022	11	0.46	$ 229	$ 106	$ 107	$ 49	**2.15**
Ten Year Totals		Yrs 1-10	7.25	$ 1,790	$ 1,253	$ 1,066	$ 773	**1.62**
Per Year Levelized					**$ 173**		**$ 107**	**1.62**

A reliability impact analysis was conducted on the portfolio projects to determine the impact of the Balanced Portfolio on the STEP reliability analysis as well as on Tier 1 entities, third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2008 STEP 10 year reliability analysis. The analysis was conducted for the entire collection of portfolio projects considered for the March CAWG meeting. The results are broken into (1) advanced projects, those projects that would be moved up in the reliability timeline due to the Balanced Portfolio; (2) new projects, projects which are now needed that were not identified in the original 10 year reliability planning horizon, but may have been needed beyond that horizon; (3) third party impacts or projects needed on neighboring systems due to the Balanced Portfolio; and (4) deferred projects, projects which are either deferred beyond the planning horizon or mitigated entirely due to the portfolio. A summary of these results is shown in the table below.

Reliability Impact (E&C Dollars)

Portfolio	Advanced Projects	New Projects	3rd Party Impacts	Deferred Projects	Net Benefit
P-3	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3A	$ 1.0	$ 3.4	$ 10.2	$ 27.7	$ 13.1
P-3C	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3D	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7
P-3E	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7

<u>April 2009</u>: Balanced Portfolio Summit

The material from the March 2009 CAWG meeting was presented at an open meeting in Dallas, TX, April 1, 2009 as an SPP open stakeholder summit. Stakeholder comments and feedback were collected during this summit and incorporated in the final analysis used in the subsequent recommendation to the CAWG on an April 10th conference call.

Feedback from stakeholders and the CAWG included a request to consider the inclusion of a portion of the Wichita – Reno Co – Summit in the final recommendation, if it was feasible, and to include the project given its benefit and costs. Additionally, Empire District Electric Company staff requested that the Chesapeake transformer project be removed from the Balanced Portfolio recommendation due to the complex nature of the project and the associated third party impacts. Also, the CAWG directed SPP to further refine cost estimates of the projects in the portfolio to include greater granularity in the itemization of project costs associated with the portfolio projects, including but not limited to material costs, right of way requirements, labor, etc. Lastly, SPP staff was directed to determine the appropriate carrying charge rates to be used for each host zone to ensure that consistent values were being applied to all projects so that they could be considered on a consistent and reasonable basis.

<u>April 2009</u>: CAWG Conference Call

The work presented during the April SPP open stakeholder summit was refined to reflect the stakeholder feedback and comments and presented to the CAWG on April 10 via conference call.

The first portfolio change was to consider the removal of the Chesapeake transformer. The results are shown in the following tables.

Portfolio 3-E No Chesapeake: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches (Million of Dollars)	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012	$ 132.3		$ 93.73		691.9
2017	$ 181.2	$ 9.79	$ 93.73	$ -	Annual
2022	$ 229.5	$ 9.65	$ 93.73	$ -	93.7

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 132	$ 132	$ 94	$ 94	**1.41**
2013	2	0.93	$ 145	$ 134	$ 94	$ 87	1.55
2014	3	0.86	$ 158	$ 135	$ 94	$ 80	1.68
2015	4	0.79	$ 171	$ 136	$ 94	$ 74	1.82
2016	5	0.74	$ 184	$ 135	$ 94	$ 69	1.96
2017	6	0.68	$ 181	$ 123	$ 94	$ 64	**1.93**
2018	7	0.63	$ 191	$ 120	$ 94	$ 59	2.04
2019	8	0.58	$ 201	$ 117	$ 94	$ 55	2.14
2020	9	0.54	$ 210	$ 114	$ 94	$ 51	2.24
2021	10	0.50	$ 220	$ 110	$ 94	$ 47	2.35
2022	11	0.46	$ 229	$ 106	$ 94	$ 43	**2.45**
Ten Year Totals	Yrs 1-10	7.25	$ 1,792	$ 1,257	$ 937	$ 679	**1.85**
Per Year Levelized				$ 173		$ 94	**1.85**

The transfer analysis for portfolio 3-E without Chesapeake is shown in the following table. The analysis concluded that $32M of transfers were required to balance this portfolio.

Attachment H Transfer Adjustments - Portfolio 3E no Ches - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30 8	$21.1	$0.0	$7.2	$7.2	$2 5	1.1
2	EMDE	($0.4)	$2.5	($3.7)	$0.8	($2.8)	$0 0	1.0
3	GRDA	$0 8	$1.8	($1.6)	$0.6	($1.0)	$0 0	1.0
4	KCPL	$8 3	$7.2	($1.4)	$2.5	$1.1	$0 0	1.0
5	MIDW	$12 8	$0.7	$0.0	$0.2	$0.2	$11 9	14.1
6	MIPU	($1.6)	$3.8	($6.7)	$1.3	($5.4)	$0 0	1.0
7	MKEC	$11.7	$1.1	$0.0	$0.4	$0.4	$10 2	8.3
8	OKGE	$26.5	$13.3	$0.0	$4.6	$4.6	$8.6	1.5
9	SPRM	($0.2)	$1.5	($2.1)	$0.5	($1.6)	$0 0	1.0
10	SUNC	$3 2	$1.0	$0.0	$0.3	$0.3	$1 9	2.4
11	SWPS	$56 0	$10.8	$0.0	$3.7	$3.7	$41 5	3.9
12	WEFA	$7.9	$3.0	$0.0	$1.0	$1.0	$3 9	2.0
13	WRI	$14.2	$10.8	($0.4)	$3.7	$3.4	$0 0	1.0
14	NPPD	$5.5	$7.5	($4.6)	$2.6	($2.0)	$0 0	1.0
15	OPPD	$2.2	$5.8	($5.7)	$2.0	($3.7)	$0 0	1.0
16	LES	($3.5)	$1.8	($5.9)	$0.6	($5.3)	$0 0	1.0
Total		$174	$94	-$32	$32	$0	$80	1.9

Next, the inclusion of the Reno Co – Summit portion of the Wichita – Reno Co. – Summit Project was considered for inclusion after the removal of the Chesapeake transformer. These results are shown below.

Portfolio 3-E No Chesapeake, with Reno Co. - Summit: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches, With RS	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
	Million of Dollars				
2012	$ 178.0		$ 105.56		789.0
2017	$ 242.1	$ 12.816	$ 105.56	$ -	Annual
2022	$ 290.4	$ 9.658	$ 105.56	$ -	105.6

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 178	$ 178	$ 106	$ 106	**1.69**
2013	2	0.93	$ 191	$ 177	$ 106	$ 98	1.81
2014	3	0.86	$ 204	$ 175	$ 106	$ 90	1.93
2015	4	0.79	$ 216	$ 172	$ 106	$ 84	2.05
2016	5	0.74	$ 229	$ 169	$ 106	$ 78	2.17
2017	6	0.68	$ 242	$ 165	$ 106	$ 72	**2.29**
2018	7	0.63	$ 252	$ 159	$ 106	$ 67	2.38
2019	8	0.58	$ 261	$ 153	$ 106	$ 62	2.48
2020	9	0.54	$ 271	$ 146	$ 106	$ 57	2.57
2021	10	0.50	$ 281	$ 140	$ 106	$ 53	2.66
2022	11	0.46	$ 290	$ 135	$ 106	$ 49	**2.75**
Ten Year Totals	Yrs 1-10	7.25	$ 2,325	$ 1,632	$ 1,056	$ 765	**2.13**
Per Year Levelized				**$ 225**		**$ 106**	**2.13**

The transfer analysis for portfolio 3-E without Chesapeake but including with Reno Co. - Summit is shown in the following table. The analysis concluded that $62M of transfers were required to balanced this portfolio

Attachment H Transfer Adjustments - Portfolio 3E no Ches with RS - Annualized

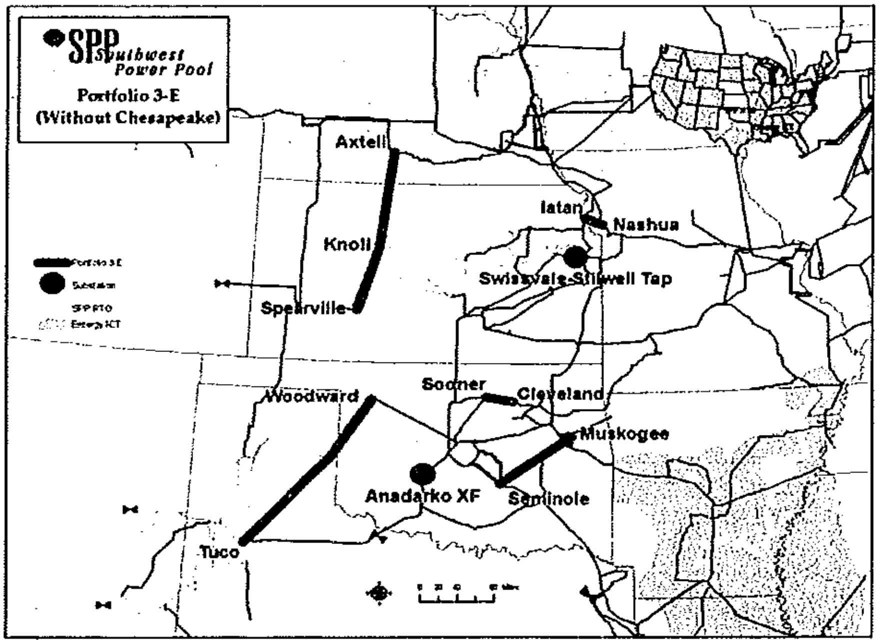
#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$25.8	$23.7	($11.8)	$13.9	$2.1	$0.0	1.0
2	EMDE	($0.1)	$2.8	($4.5)	$1.6	($2.9)	$0.0	1.0
3	GRDA	$0.1	$2.1	($3.2)	$1.2	($1.9)	$0.0	1.0
4	KCPL	$8.7	$8.2	($4.2)	$4.8	$0.5	$0.0	1.0
5	MIDW	$12.8	$0.8	$0.0	$0.4	$0.4	$11.6	10.7
6	MIPU	($5.6)	$4.3	($12.4)	$2.5	($9.9)	$0.0	1.0
7	MKEC	$11.3	$1.2	$0.0	$0.7	$0.7	$9.4	6.0
8	OKGE	$36.8	$15.0	$0.0	$8.8	$8.8	$13.0	1.5
9	SPRM	($0.3)	$1.6	($2.9)	$1.0	($1.9)	$0.0	1.0
10	SUNC	$3.6	$1.1	$0.0	$0.7	$0.7	$1.8	2.0
11	SWPS	$55.9	$12.2	$0.0	$7.1	$7.1	$36.6	2.9
12	WEFA	$11.8	$3.3	$0.0	$2.0	$2.0	$6.5	2.2
13	WRI	$59.9	$12.2	$0.0	$7.1	$7.1	$40.6	3.1
14	NPPD	$5.4	$8.5	($8.0)	$5.0	($3.0)	$0.0	1.0
15	OPPD	$2.7	$6.6	($7.7)	$3.8	($3.8)	$0.0	1.0
16	LES	($3.9)	$2.0	($7.1)	$1.2	($5.9)	$0.0	1.0
Total		$225	$106	-$62	$62	$0	$120	2.1

An analysis was conducted to determine the impact on total Annual Transmission Revenue Requirement (ATRR) for each zone in the tariff. The results are shown for portfolio 3-E, "3-E no Chesapeake" and "3-E no Chesapeake with Reno Co – Summit". These results are shown in the following table.

Total ATRR for Proposed Balanced Portfolios

	BP 3E	3E no Ches	BP 3E no Ches w RS
Zone	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR
AEPW	$ 175,484,688	$ 177,104,393	$ 174,641,806
SPRM	$ 8,934,262	$ 8,659,884	$ 8,524,079
EMDE	$ 14,660,746	$ 14,007,997	$ 14,294,209
GRDA	$ 25,891,875	$ 26,032,862	$ 25,312,950
KCPL	$ 43,661,239	$ 44,709,872	$ 45,060,781
OKGE	$ 118,952,010	$ 116,849,771	$ 122,735,245
MIDW	$ 5,277,346	$ 5,170,672	$ 5,469,320
MIPU	$ 19,618,726	$ 19,420,118	$ 15,471,824
SWPA	$ 9,431,500	$ 9,431,500	$ 9,431,500
SWPS	$ 104,700,870	$ 102,989,030	$ 107,781,536
SUNC	$ 16,092,722	$ 15,934,343	$ 16,377,746
WEFA	$ 25,545,806	$ 25,077,005	$ 26,389,469
WRI	$ 128,845,823	$ 129,135,340	$ 134,286,149
MKEC	$ 7,723,354	$ 7,557,124	$ 8,022,505
LES	$ 8,877,057	$ 8,718,252	$ 8,313,564
NPPD	$ 53,140,390	$ 53,181,895	$ 53,125,563
OPPD	$ 38,645,990	$ 38,661,265	$ 39,227,136
	$ 805,484,404	**$ 802,641,325**	**$ 814,465,382**

Portfolio 3-E "Adjusted"



Portfolio 3-E with Reno Co – Summit, without Chesapeake

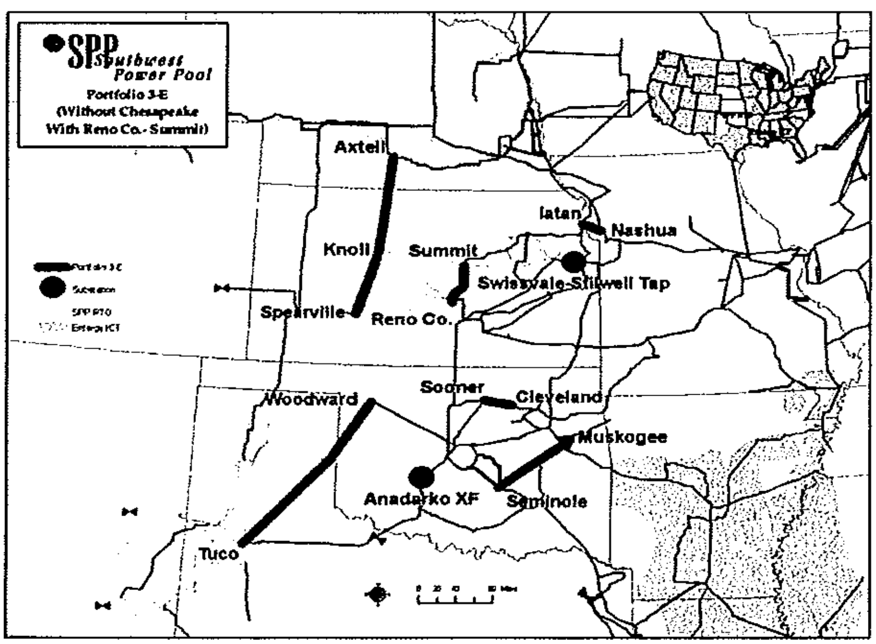


EXHIBIT 6

Recommendation

The CAWG endorsed portfolio 3-E "Adjusted" (without Chesapeake, without Reno Co – Summit). Portfolio 3-E "Adjusted" provides a significant benefit vs. cost to the SPP region, as well as having lower balance transfer requirements. Portfolio 3-E "Adjusted" contains a comprehensive group of economic projects addressing many of the top constraints in the SPP. The projects associated with portfolio 3-E "Adjusted" are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The supporting material for portfolio 3-E was presented to the Markets and Operations Policy Committee (MOPC) in April 2009. The MOPC reviewed and discussed the portfolio options and the impact on the footprint. After discussion, the MOPC endorsed the recommendation for Balanced Portfolio 3-E "Adjusted" pending issuance of the final report, according to the SPP Tariff.

Portfolio 3-E "Adjusted" provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58. Additionally, it should be noted that the Portfolio could incur a construction cost increase of up to 113%, or more than double the estimated construction cost, and still provide a benefit to cost ratio of 1.0 for the region. Therefore, the Balanced Portfolio could have a total E&C final cost of over $1.4B and still provide benefits greater than costs.

Estimated SPP average customer impact (based on 1,000 kWh/month usage)

Existing Zonal ATRR	Base Plan		New Base Plan NTCs		P-3E Costs
	1/3	2/3	1/3	2/3	Annual
$688M	$7M	$14M	$33M	$66M	$106 M
Total: $808M					13%
Avg. Cost Per Customer Per Month: $7.58					88 ¢

P-3E "Adjusted" Benefit = $1.66

The CAWG and MOPC recommendation of Portfolio 3-E "Adjusted" was presented to the SPP Regional State Committee (RSC) during their April 27, 2009 meeting in Oklahoma City where Portfolio 3-E "Adjusted" was endorsed by the RSC. Staff then presented to the MOPC and RSC the recommended Portfolio during the SPP Board of Directors meeting on April 28th. The SPP Board approved the projects in Balanced Portfolio 3-E "Adjusted" for inclusion in the SPP Transmission Expansion Plan. The SPP Board went on to direct staff to finalize the Balanced Portfolio Report in accordance with the SPP tariff. Furthermore, the Board directed that Notification To Construct letters for the Projects in the Balanced Portfolio be issued once the required Balanced Portfolio Report is finalized after CAWG review and MOPC approval.

Balanced Portfolio Stakeholder Process
The SPP Regional State Committee (**RSC**) requested the Cost Allocation Working Group (CAWG) to consider alternative cost allocations for economic upgrades.

Cost Allocation Working Group (CAWG)
The CAWG has been the primary stakeholder group overseeing development of the Balanced Portfolio. The CAWG created the Economic Concepts whitepaper. Many representatives from other SPP stakeholder groups attend the CAWG's monthly meetings.

Trapped Generation Task Force (TGTF)
This CAWG Task Force determined wind assumptions in the Adjusted Production Cost (**APC**) models.

Economic Modeling and Methods Task Force (EMMTF)
The EMMTF focused on the planning process and development of additional economic benefit metrics. It initially worked to acquire detailed data on generation units in the model. The EMMTF addressed confidential issues. The EMMTF is currently the Economic Studies Working Group (ESWG)

Regional Tariff Working Group (RTWG)
The RTWG facilitated acquiring FERC approval of Attachment O language for the Balanced Portfolio process.

Markets and Operations Policy Committee (MOPC), Board of Directors (BOD), Regional State Committee (RSC)
These groups will review and approve the Balanced Portfolio.

Planning Summits
Proposed Balanced Portfolios and related concepts were shared at planning summits in May and August.

Posting
Portfolios and associated information are posted on SPP.org:
http://www.spp.org/section.asp?pageID=120

Appendix

Final Benefit to Cost Results for the Balanced Portfolio

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Portfolio 3-E "Adjusted" 10 yr B/C with Reliability Impact

Portfolio 3-E "Adjusted"			Total Benefit	Incremental Benefit	Million of Dollars Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
2012			$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017			$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022			$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

The following three tables break out the benefits from the economic analysis. These tables do not include the reliability benefits. The numbers represent a change between the change and base cases, with the change case including the Balanced Portfolio. A negative number denotes a reduction in cost which is considered a benefit. Likewise a positive number is a cost increase.

2012 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$21,285,000	($14,003,000)	$31,439,000	($24,155,000)
EMDE	$2,990,000	($2,096,000)	$207,000	$687,000
GRDA	$72,000	$159,000	$982,000	($751,000)
KCPL	$4,273,000	($637,000)	$9,994,000	($6,358,000)
LES	$1,297,000	$1,226,000	$0	$2,523,000
MIDW	($350,000)	($8,783,000)	$0	($9,133,000)
MIPU	$6,027,000	($3,968,000)	($5,000)	$2,064,000
MKEC	($7,563,000)	($2,015,000)	($925,000)	($8,653,000)
NPPD	$6,519,000	($28,000)	$11,726,000	($5,235,000)
OKGE	($85,787,000)	$52,737,000	($9,386,000)	($23,664,000)
OPPD	$2,165,000	$160,000	$4,247,000	($1,922,000)
SPRM	$734,000	($42,000)	$668,000	$24,000
SUNC	($5,206,000)	($2,096,000)	($5,171,000)	($2,131,000)
SWPS	($70,516,000)	$31,769,000	($519,000)	($38,228,000)
WEFA	($13,163,000)	$4,105,000	($375,000)	($8,682,000)
WRI	($5,257,000)	($359,000)	$2,131,000	($7,747,000)

2017 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$55,943,000	($17,738,000)	$71,548,000	($33,344,000)
EMDE	$3,525,000	($3,272,000)	$100,000	$153,000
GRDA	($28,000)	$163,000	$889,000	($754,000)
KCPL	$6,229,000	($3,576,000)	$11,897,000	($9,244,000)
LES	$2,019,000	$1,970,000	$0	$3,989,000
MIDW	($764,000)	($14,046,000)	$0	($14,810,000)
MIPU	$5,483,000	($3,915,000)	$79,000	$1,489,000
MKEC	($10,893,000)	($2,667,000)	($793,000)	($12,767,000)
NPPD	$5,842,000	($779,000)	$10,741,000	($5,678,000)
OKGE	($129,794,000)	$88,180,000	($14,032,000)	($27,582,472)
OPPD	$3,030,000	$276,000	$5,663,000	($2,357,000)
SPRM	$603,000	($60,000)	$251,000	$292,000
SUNC	($7,575,000)	($2,386,000)	($6,776,000)	($3,185,000)
SWPS	($80,497,000)	$18,914,000	($924,000)	($60,659,000)
WEFA	($22,863,000)	$14,785,000	($468,000)	($7,610,000)
WRI	($14,392,000)	($1,073,000)	$1,674,000	($17,139,000)

2022 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange In Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$67,322,000	($22,618,000)	$83,884,000	($39,181,000)
EMDE	$4,703,000	($4,421,000)	$91,000	$191,000
GRDA	($480,000)	$123,000	$1,003,000	($1,360,000)
KCPL	$6,624,000	($2,828,000)	$14,974,000	($11,178,000)
LES	$2,249,000	$2,150,000	$0	$4,399,000
MIDW	($736,000)	($14,659,000)	$0	($15,395,000)
MIPU	$2,680,000	($1,044,000)	($19,000)	$1,655,000
MKEC	($14,429,000)	($1,525,000)	($287,000)	($15,667,000)
NPPD	$6,488,000	($1,250,000)	$10,748,000	($5,510,000)
OKGE	($138,499,000)	$85,998,000	($22,388,000)	($30,113,000)
OPPD	$3,787,000	$378,000	$6,258,000	($2,093,000)
SPRM	$637,000	($317,000)	$301,000	$19,000
SUNC	($7,360,000)	($2,495,000)	($3,923,000)	($5,932,000)
SWPS	($89,381,000)	$2,205,000	($1,184,000)	($85,992,000)
WEFA	($20,837,000)	$13,197,000	($575,000)	($7,065,000)
WRI	($11,595,000)	($6,705,000)	$2,730,000	($21,030,000)

The following table demonstrates the benefits, costs and transfers on an annualized basis after the resulting reliability impacts, both the advancement and deferral, are accounted for. The net B/C impact of the reliability projects was an approximate marginal increase of .01 of the total Portfolio.

Portfolio 3-E "Adjusted" Annualized Benefits, Costs and Transfers, including Reliability Impacts

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 6 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	**1.1**
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	**1.0**
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	**1.0**
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	**1.0**
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	**14.1**
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	**1.0**
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	**8.3**
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	**1.6**
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	**1.0**
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	**2.7**
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	**3.9**
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	**2.0**
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	**1.0**
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	**1.0**
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	**1.0**
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	**1.0**
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

The spreadsheet which was used to calculate the transfers in the above table can be found on the Balanced Portfolio section of the SPP Website.[††]

[††] http://www.spp.org/section.asp?pageID=120

The table shown below demonstrates the MW-mi impact of the deferred reliability projects. This impact is used to determine who receives the benefit for the deferral of each reliability project from the portfolio.

Portfolio 3-E – Reliability Impact MW-mi analysis

	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	CLEARWATER-GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	EL RENO- EL RENO SW 69KV CKT 1 - Upgrade	LONGVIEW-WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps
Date	2015	2015	2016	2017	2018
AEPW		1.6%			
EMDE					
GRDA					
KCPL					
MIDW	46.7%	16.2%			
MIPU					100.0%
MKEC	19.4%	36.0%			
OKGE	1.3%	5.3%		24.7%	
SPRM					
SUNC	9.9%	10.9%			
SWPS		4.4%			
WEFA				75.3%	
WRI	22.6%	22.1%	100.0%		
NPPD		3.6%			
OPPD					
LES					
	100.0%	100.0%	100.0%	100.0%	100.0%

Reliability Results

The reliability results for the Portfolio 3E "Adjusted" are shown in the following table. The projects are broken into "deferred" and "mitigated" issues and "new" issues. Additionally, projects are shown for potential third party impacts. Note that a project highlighted in yellow (e.g. EARLSBORO – FIXICO) indicates that the project is merely advanced in time and not an entirely new issue.

Portfolio 3e without Chesapeake

Costs of STEP Projects Solved by Portfolio 3e, with STEP date

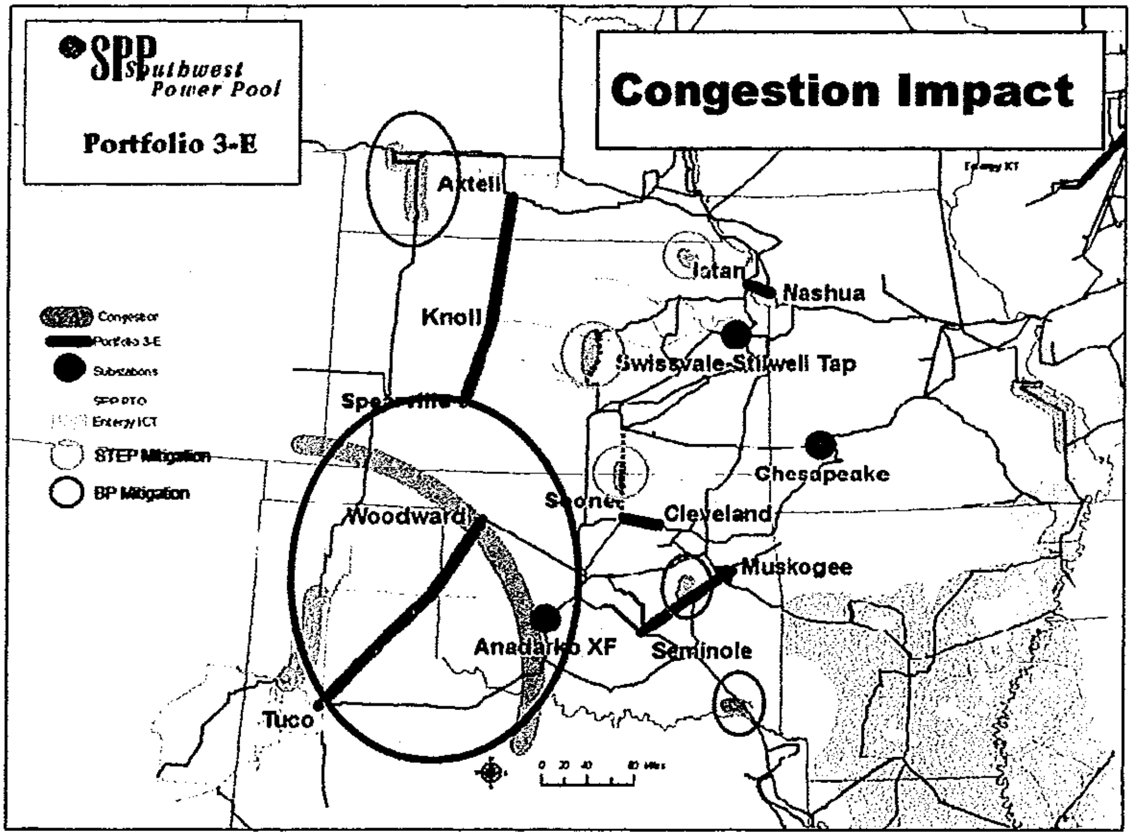
Issue Type	Project Name	Area	STEP Date	Deferred costs to TO: STEP projects solved by BP
Overload	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	WERE	16SP	$3,324,375
Overload	EL RENO - EL RENO SW 69KV CKT 1 - Upgrade	WFEC	17SP	$1,950,000
Overload	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	WERE	15SP	$12,487,500
Overload	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	MIDW	15SP	$7,965,000
Overload	LONGVIEW - WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps	MIPU	18SP	$50,000
Voltages	None			
			Totals	$25,776,875

Cost of potential mitigation for New issues due to implementation of portfolio improvements

Description	Project Name	Area	Date of Needed Mitigation	SPP New Issues, Cost	Third Party Issues: Cost
Overloads-SPP	EARLSBORO - FIXICO 69KV CKT 1 - Increase limits (trap, CT ratio)	OKGE	13SP	$150,000	
Overloads-SPP	MED LODGE-PRATT, ST.JOHN-GREATBENDTAP 115 KV LINE REBUILD	MKEC	18SP	$15,840,000	
Overloads-Third Party	PLATTE CITY 161/69KV TRANSFORMER CKT 1 - Replace AECI XFMR	MIPU-AECI	13WP		$7,500,000
Voltages	None				
			Totals	$15,990,000	$7,500,000
			Grand Total	$23,490,000	
			Net: Solved Minus SPP New	$9,786,875	
			Net: Solved Minus Total New	$2,286,875	

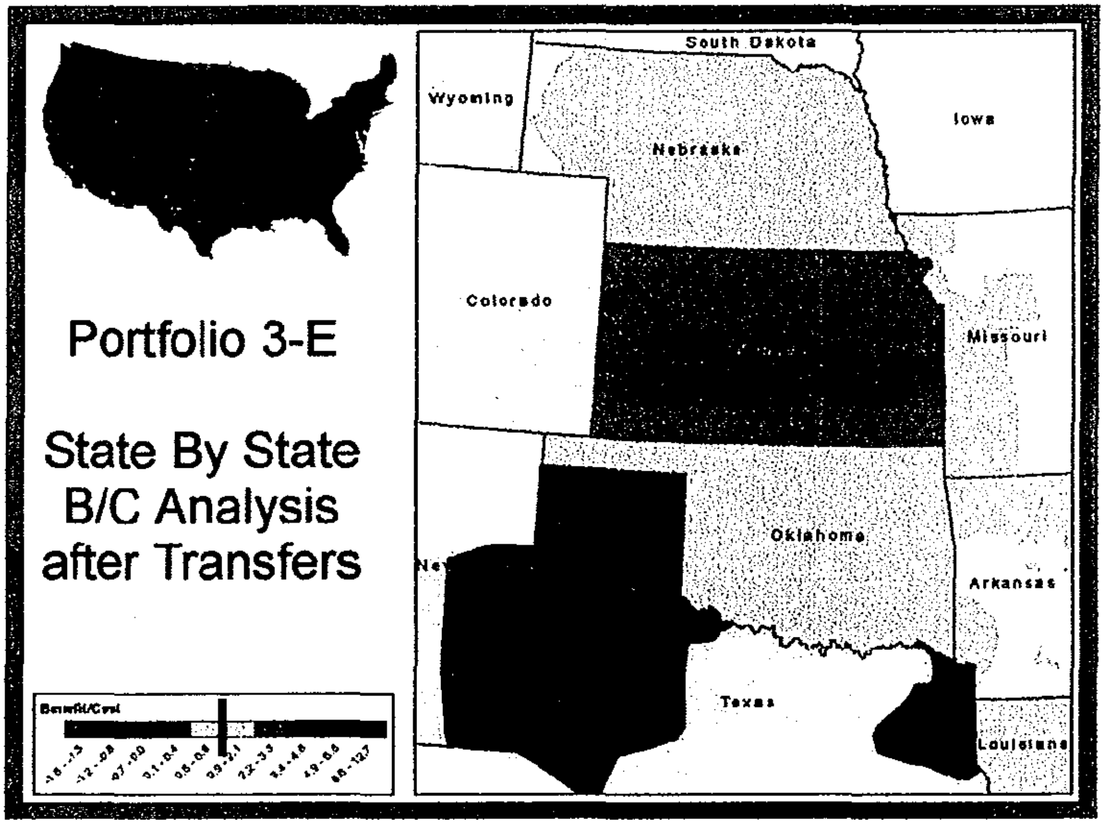
It should be noted that the third party impact of Platte City 161/69 kV transformer was coordinated with Associated Electric Cooperative, Inc. (AECI) staff. AECI staff did not see the same issue in their analysis.

Congestion Impact



The graphic shown above represents the top flowgates in the SPP EIS Market as they exist today. Congestion here is shown as an orange highlight. Portfolio projects, shown on the map as bold red highlight lines, relieve or mitigate much of the congestion that exists today. The congestion relief provided by the portfolio is shown as a green circle. Projects in the 10-year STEP plan that provide additional congestion relief are shown in light blue.

B/C by State



The diagram above demonstrates the B/C ratio of the Balanced Portfolio divided by state boundaries. While it should be noted that the portfolio of projects provides broad, regional benefits to all SPP members, this diagram is a good representation of the balance aspect of the portfolio broken into the respective state boundaries. This picture represents the balance of the portfolio after transfers have taken place in order to balance all zones. As can be seen from the diagram, all states have a B/C ratio greater than 1

SPP Balanced Portfolio Report

	Zone	OKGE	OKGE	OKGE	SPS	KCPL	NPPD	ITC	KCPL	OKGE
	Project	Sooner - Cleveland	Seminole - Muskogee	Tuco - Woodward	Tuco - Woodward	Iatan - Nashua	Knoll - Axtell	Spearville - Knoll - Axtell	Swissvale - Stilwell Tap	Anadarko Sub
	Projected In-Service Date	12/31/2012	12/31/2013	5/1/2014	5/1/2014	6/1/2015	6/1/2013	6/1/2013	6/1/2012	12/31/2011
Cost	Total Cost	$33,530,000	$129,000,000	$79,000,000	$148,727,500	$54,444,000	$71,377,015	$165,180,000	$2,00,000	$8,000,000
	Cost Per Mile	$900,000	$1,250,000	$900,000	$688,750	$1,214,800	$1,416,667	$846,000		$666,666
	Miles	36	100	72	178	30	45	170		3
	Substation Cost	$1,130,000	$4,000,000	$15,000,000	$26,130,000	$18,000,000	$6,827,000	$16,800,000		
	Fixed Charge Rates	15.1%	15.1%	15.1%	12.1%	15.1%	13.5%	12.0%	15.1%	15.1%
Conductor	Size	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1192.5, 38/19 Grackle TW	2 Conductor Bundle 477 T2 Hawk	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	138 kV line
	Design	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit		
	Electrical Capacity	2578 Amps 1540 MVA at 345kV	3000 Amps 1800 MVA at 345kV	2578 Amps 1540 MVA at 345kV	2468 Amps Normal	4,100A	2,324 amps per bundle	3,000 amps		
	Other	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire					
Structure	Type	H-frame	Single Pole	H-frame	H-frame	H-frame	Single Pole	H-frame		
	Materials	Steel	Steel	Steel	Steel	Steel	Steel	Steel		
	Base	Direct buried w/ aggregate backfill	Steel base plate reinforced concrete	Direct buried w/ aggregate backfill	Direct buried with aggregate or natural backfill	Direct Embed	Poured concrete anchor bolt	Direct embed concrete piers		
	NESC Assumption	Heavy	Heavy	Heavy	Heavy	Heavy	Heavy, 1.5 inch ice load			
	Dead Ends	Unknown	Unknown	Unknown	Unknown @ $65,000 each	16 @ $50,000 each	20 @ $140,000 each	60 @ $50,000 each	2 to 3 Deadends	
	Under build	No	No	No	No	No	No	No		
Substations	Transformers	Breakers and Relays	Two 345/138kV	345/138kV 50 MVAR reactor bank	345/230kV 560 MVA	600 MVA	None	345/230kV 200 MVA		345/138 kV
	Breaker Scheme	Ring-bus	Ring-bus, replace 2 2,000 A breakers	Ring-bus	345kV Ring	Ring-bus	Ring-bus	Ring-bus	2 breakers, breaker disconnects, line panels	
	Protection Scheme	included in sub cost	included in sub cost	included in sub cost	$1,000,000	$400,000	$156,000	$220,000		included in sub cost
	Voltage Control			+/- 50 MVAR						
	Cost (millions)	$1	$4	$15	$26	$18	$4	$14		
Construction Labor	Amount	1/3 of line construction	1/3 of line construction	1/3 of line construction						
	Cost (millions)	$14	$52	$27	$18	$7	$17	$49		
Eng Design, Project Management, Permitting	ROW	150ft @$5,500 an acre	200ft @$5,500 an acre	150ft @ $5,500 an acre	150ft	160ft	200ft	150ft		
	ROW Condition	rural, pasture	rural, pasture, hill, rock, high tree clearing cost	rural, pasture	Farmland and Pasture	50% Urban 50% Rural	rural farmland rainwater basin	rural, agri, pasture, range land	No ROW acquisition required	
	Permitting/Certifications	RR and Highway	RR and Highway	RR and Highway	Texas CCN, Highway, storm water, RR, County roads	Yes	NE Power Review Board, NPSC, RR, Airport, etc	Included		
	Escalation Rate	2.5% per year	2.5% per year	2.5% per year		2.5% per year	3% per year	0% for 2 years		
	Eng. Design / Proj. Mang.				Included	$349,000	$8,798,000	$13,770,000		
	Total Cost (millions)	cost included	cost included	cost included	$15	$26	$18	$24		
Loadings and Overheads	Type 1	included in total cost	Included in total cost	Included in total cost	Included in total cost	$123,000	Included in total cost	20% of line and substation work, $26.7 million		
Other Cost Factors and Notes			$25,000/ mile cost included for tree clearing		Included in substation cost is $6.52 mil for mid-point reactor station	Large portion involves developed urban areas	Environmentally sensitive areas, possible double-circuit for 10 miles	$4.56 mil addition contingency added		

Study Assumptions

Fuel Price Assumptions – Fuel price assumptions are taken from EIA forecasts and updated according to member specific data for particular plants. For the purpose of this study, the average gas price is $6.50/MMBtu starting in 2012. The price is then escalated for inflation for the years 2017 and 2022 at the rate of 1.81%.

Environmental Costs - Carbon sensitivities have been conducted, but were not included in the portfolio selection process. A price of $15 and $40 per metric ton was used in these sensitivities. No sensitivity analysis was conducted for higher SO_2 or NO_X prices. SO_2 and NO_X were priced at $466.50 and $1742.16 per ton respectively.

Plant Outages – Stakeholders provided outage and maintenance rates to SPP staff through the EMMTF data collection effort. Forced outages were taken as a single draw and locked for the change and the base case. Similarly, maintenance outages were also locked down from a single scheduled pattern. These outage rages were plant specific and provided by each member.

Load Forecast – Load forecasts for the region were provided by each stakeholder in early 2009 for the projected years of 2012, 2017 and 2022 through the EMMTF update effort. These non coincident peak loads for the region were, in aggregate, as follows: 2012 - 43,068MW, 2017 – 47,109 MW, 2022 – 51,530 MW. The zonal shares of the 2012 load submittals were used to allocate the costs on a load ratio share basis.

Resource Forecast – The CAWG and EMMTF determined the criteria for inclusion of new resources into the Balanced Portfolio analysis. It was determined that only plants with firm transmission service and signed agreements or plants that were currently under construction would be included in the analysis. The following units are those which were included as a future resource.

- Turk (618 MW)
- Whelan Energy Center 2 (220 MW)
- Iatan 2 (900 MW)
- Central Plains (99 MW)
- Cloud County (201 MW)
- Flat Ridge (100 MW)
- Red Hills (120 MW)
- Smoky Hills (359 MW)

Hurdle Rates – A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW was used to commit resources across regional boundaries.

Demand Side Management – Interruptible load was modeled as supplied by the LSE's.

Market Structure – The simulation was conducted considering a single balancing authority and a day-ahead market structure for the SPP region.

Flowgate Assumptions – The NERC Book of Flowgates was used as the source for flowgates used in the analysis.

DC Tie Profiles - Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

Wind Profiles – Historical wind profiles were used to simulate the wind output at each wind farm.

Load Profiles – Load profiles were simulated as supplied by each LSE through the EMMTF effort.

RMR Requirements – Each Balancing Authority submitted their respective Reliability Must Run (RMR) requirements to be simulated in the analysis.

Operating Reserves – SPP's current reserve sharing program (as of 2008) was used in the simulation for operating reserves.