MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-11-395 and PU-11-396

Rebuttal Testimony
of
Andrea L. Stomberg

**Q. Please state your name and business address.**

A. My name is Andrea L. Stomberg and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

**Q. What is your position with Montana-Dakota Utilities Co.?**

A. I am the Vice-President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

**Q. What is the purpose of this rebuttal testimony?**

A. My testimony is intended to provide further support for Montana-Dakota's proposal to construct an 88 MW combustion turbine at the Heskett Station in Mandan, North Dakota in response to the Initial Testimony of Advocacy Staff witness Richard Hahn. In particular, I will elaborate on the benefits of an owned on-system generation resource located at the Heskett site.

**Q. Do the North Dakota Advance Determination of Prudence (ADP) and Certificate of Public Convenience and Necessity (CPCN) statutes require least cost, as suggested by Mr. Hahn?**

A. No. Least cost is not a requirement for issuing an advanced determination of prudence or a certificate of public convenience and necessity. Not all prudent resources are necessarily least cost resources and vice versa. Montana-Dakota seeks the best overall value for its customers, which may mean the selection of a resource that does not carry the least cost price tag. Also, the statute contains a rebuttable presumption that resources located in the state are prudent and requires the Commission to consider the benefits of having the resource located in the state. These provisions clearly imply that the resource need not be least cost to be deemed prudent.

**Q. Did Mr. Hahn consider these qualitative benefits in his analysis and recommendation?**

A. Mr. Hahn's analysis and testimony focuses on the modeling conducted by the Montana-Dakota in the development of its 2011 IRP. He offers various changes that he believes could have or should have been made to the modeling; some of which the Company agrees and some of which it disagrees as discussed in the Rebuttal Testimony of Mr. Neigum. Based on his analysis of the modeling results, Mr. Hahn recommended that Montana-Dakota's applications be denied because the modeling identified the Illinois power purchase proposal as a lower cost resource alternative.

It is important to recognize that the modeling is designed to identify the least cost resource alternatives based upon the assumptions built into the model. It is not intended to be the final or definitive step in determining the best generation alternative for the customers. After the modeling has identified the least cost alternatives, the Company must consider subjective and qualitative factors in making final selections of the best alternatives. Mr. Hahn's testimony did not address this aspect of the selection process.

**Q. What are the benefits of an on-system resource compared to an off-system generating resource?**

A. Resources located on the Montana-Dakota integrated system, in contrast to those located outside of this system, particularly those located outside the states of Montana-Dakota's service area, provide many benefits to customers and communities including:

- Increased system reliability,
- Job creation and employment opportunities,
- Higher state income tax revenue,
- Higher local property tax revenue, and
- Indirect revenue additions to local communities from purchases of materials and services.

**Q. Do off-system out-of-state generating resources provide these same benefits to the states and communities that Montana-Dakota serves?**

A. No, they do not.

**Q. Are there other benefits of an owned resource rather than a power purchase agreement (PPA) that are not reflected in the modeling analysis?**

A. Certainly. The modeling analysis captures a 20-year period and extends those benefits over a 50-year time frame. If a PPA was entered into for the entire 20 years, clearly, another resource or PPA would have to be available at the end of that term. Because the cost of the replacement resource is unknown, the model prices the resource at the same cost as the PPA that it replaced. Obviously, that is an unlikely assumption that can provide, as it does in this instance, a modeling bias in favor of power purchase arrangements. A generating resource such as a combustion turbine is expected to have at least a 40 year life, and hence provides longer-term cost certainty. For instance, Montana-Dakota's Miles City combustion turbine, a 25 MW resource that was constructed in 1972, has provided value to customers for 39 years. It has a current monthly value of $0.91/kw, compared to the Illinois proposed resource at $4.55/kw. In this example, replacing the Miles City combustion turbine capacity today with a PPA priced at the Illinois proposal would cost Montana-Dakota customers an additional $1.1 million dollars annually. Montana-Dakota customers have received the cost benefits of Montana-Dakota's ownership of this resource for a number of years and will continue to receive this value until the turbine is retired. This value would not have been reflected in any least cost modeling of generation alternatives conducted in 1972.

**Q. What are the reliability benefits that a 88 MW combustion turbine located near Mandan, North Dakota will have for the integrated system?**

A. A new generating resource located near the Heskett Station will provide reliability benefits by adding an additional resource in an area that is experiencing growth. While this resource will help meet the growing capacity and energy needs of Montana-Dakota's interconnected system customers, it adds particular value to Montana-Dakota's largest electric load area, the Bismarck-Mandan area.

In the Bismarck-Mandan area, transmission outages at the East Bismarck Substation or Heskett Substation can impact the Company's ability to reliably serve its customers. On December 5, 2011, Montana-Dakota experienced the failure of a transformer at Heskett Unit #1 which caused both Heskett coal-fired power units to trip off-line. The failure of this transformer led to the failure of a larger transformer at the Heskett Substation. The resultant loss of generation in the Bismarck-Mandan area coupled with the inability to inject power into the area from the Heskett Substation because of the larger transformer failure, caused Montana-Dakota, to announce a public appeal to conserve energy as well as request the running of all distributed generation in the Bismarck-Mandan area on the December 6, 2011.

**Q. How would the proposed 88 MW combustion turbine (Heskett CT) been used during that event?**

A. Had the proposed Heskett CT been available, it would have been started to quickly provide additional energy support into the Bismarck-Mandan area and avert the public appeal to conserve energy on the sixth of December. The Heskett CT will be connected to the 115kV transmission system and would have been able to support loads in the Bismarck-Mandan area even with the failed transformer at the Heskett Substation. It takes around 24 hours to restart Heskett Unit #2, while the new CT is expected to be able to achieve full load within 30 minutes.

**Q. What would have happened if Heskett Unit #2 had not been available to restart or if a transmission problem had occurred at the East Bismarck Substation?**

A. If Montana-Dakota had not have been able to start the Heskett Unit #2 generator or if a transmission problem had occurred at the East Bismarck Substation, we would have had to implement load-shedding procedures in the Bismarck-Mandan area.

**Q. Are there other reasons this location is important?**

A. Yes. For many years, Montana-Dakota's integrated system customers have benefitted from transmission facilities Montana-Dakota shares with the Western Area Power Administration (WAPA) under a transmission service agreement. This agreement will expire permanently on December 31, 2015, and Montana-Dakota will be required to take additional transmission service from the WAPA Integrated Transmission System (IS) for loads that the Company is unable to serve without support from the IS, particularly in the western portion of its service territory. An additional generating resource at Heskett Station will help offset the need to use the IS to serve customer load requirements east of Beulah, North Dakota. The monetary benefit of having an 88 MW combustion turbine at the Heskett location is the potential avoidance of paying $3.1 million (in

2011 dollars) annually to the WAPA IS, based on Montana-Dakota's projected usage of the IS lines.

**Q. Does a generating resource in Illinois provide these same benefits?**

A. No, it does not.

**Q. Does selection of a combustion turbine at the Heskett site offer other benefits and opportunities?**

A. Montana-Dakota has evaluated the Heskett site for a possible future combined cycle application of the proposed 88 MW Heskett CT in conjunction with the Heskett Unit #1 steam turbine. The Heskett Unit #1 plant has been in service since 1954. When this plant is ultimately retired, the steam turbine equipment will be well-suited to be used in a combined cycle application with the proposed 88 MW Heskett CT. In this scenario, the Company would only need to install a heat recovery steam generator onto the exhaust of the 88 MW Heskett CT to continue to power the Heskett Unit #1 steam turbine and generator. This solution allows Montana-Dakota to bring continuing value from this depreciated asset to our customers. As discussed in the Application for an Advance Determination of Prudence, even without the addition of the combined cycle application, the Heskett location offers opportunities for synergies by being co-located at the site with the Heskett coal plants.

**Q. Did the EGEAS modeling for the 2011 IRP reflect the economic efficiencies of combining the 88 MW Heskett CT with the Unit #1 steam turbine and generator?**

A. No. The economic opportunities of this combination were not reflected in the EGEAS modeling in order for the model to select least cost alternatives before consideration of these opportunities and other qualitative factors.

**Q. Would the inclusion of the synergies such as staffing and infrastructure existing at the Heskett Station strengthen the economic analysis for selection of the 88 MW Heskett CT project?**

A. Yes, it would have strengthened the economic analysis, but these synergies were excluded in order not to bias the model.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
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Before the Public Service Commission of North Dakota

Case No. PU-11-395 and PU-11-396

Rebuttal Testimony
of
Darcy J. Neigum

**Q. Please state your name and business address.**

A. My name is Darcy J. Neigum and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

**Q. What is your position with Montana-Dakota Utilities Co.?**

A. I am the System Operations and Planning Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

**Q. Are you the same Darcy J. Neigum that submitted Direct Testimony in this proceeding?**

A. Yes, I am.

**Q. What is the purpose of this rebuttal testimony?**

A. The purposes of my rebuttal testimony is to respond to the Initial Testimony of Mr. Richard Hahn filed on behalf of the North Dakota Public Service Commission Advocacy Staff on December 12, 2011 in this proceeding. I will address why the Company's request for an Advance Determination of Prudence (ADP) and a Certificate of Public Convenience and Necessity (CPCN) for an 88 MW simple cycle combustion turbine near the R.M. Heskett Station in Mandan, North Dakota (CT Project) is in the best interest of Montana-Dakota's customers. I will demonstrate that the need for additional resources identified by the Company and accepted by Mr. Hahn are best met with the addition of an on-system resource. I will address Mr. Hahn's comments relative to resource alternatives modeled by the Company and the results of Mr. Hahn's Alternative Analysis.

**Q. Would you please summarize why the Commission should not adopt Mr. Hahn's recommendation and instead approve the Company's request for an ADP and a CPCN for the CT Project as a needed and prudent resource for meeting the generation capacity requirements of its customers?**

A. Yes. As explained in more detail below, Mr. Hahn's Alternative Analysis indicating that a power purchase agreement from an Illinois combustion turbine resource (IL Proposal) is significantly less costly than the Company's 88 MW Combustion Turbine Project substantially overstates any cost advantage of the IL Proposal and does not address the benefits associated with addition of a generating resource within the Company's integrated system. Mr. Hahn's allegation that the Company's modeling unduly biased the 88 MW Combustion Turbine Project is not correct as I will discuss in detail below and the risks associated with the purchase power agreement located outside Montana-Dakota's service area have not been adequately addressed by Mr. Hahn.

Finally, the use of capacity credits from the IL Proposal is only a paper transaction that does not provide the ability to physically deliver the energy from the project to Montana-Dakota's service area and is not a prudent long-term resource for Montana-Dakota's customers.

## NEED FOR THE RESOURCE

**Q. Does Mr. Hahn dispute Montana-Dakota's need for capacity resources in the future?**

A. No, as Mr. Hahn indicates on Page 17 of his Initial Testimony, "The load forecast combined with the expiration of existing contracts in the 2011 to 2015 time period demonstrate a need for some new capacity."

**Q. What is causing Montana-Dakota's need for capacity resources in 2015?**

A. Montana-Dakota's need for capacity resources is driven by customer growth and the expiration of the We Energies capacity purchase agreement in May of 2015 at which point the Company is forecasted to be deficit 149 MWs or 149 MISO planning resource credits (PRCs) representing 25.3 percent of the total required PRCs.

**Q. What were the Company's growth projections in the 2011 Integrated Resource Plan (2011 IRP)?**

A. The five year growth levels included in the 2011 IRP were 5.2 percent for energy requirements and 2.3 percent for demand requirements, which is reduced by the forecasted impact of new demand response programs.

**Q. What are the actual growth levels that the Company has seen in 2011?**

A. Even with an unseasonably cool summer, retail sales through November 2011 are 1.5 percent above those for the same period in the 2011 IRP. The Company also set an all-time summer peak of 535 MW in August which is 10 MWs over the previous all-time summer peak. As a note, 537 MW is the forecasted peak demand for 2013 in the 2011 IRP.

**Q. Why do the Company's 2011 IRP load growth rate projections decline after 2016?**

A. Due to territorial limitations in many of the communities that Montana-Dakota serves, it is forecast that saturation of Montana-Dakota's market space will slow growth rates to historical growth levels after 2016. However, with the continued growth of oil field activity in the Bakken area and the potential for significant commercial load growth within Montana-Dakota's service areas in response to the oil activity, the potential exists to see growth levels similar to the EGEAS High Customer Growth Scenario for several years.

**Q. What is the current view of excess capacity available in the MISO market?**

A. As Mr. Hahn indicates on Page 10 of his Initial Testimony, MISO's 2010 Long Term Resource Assessment states: "The projected Midwest ISO reserve margin ranges from 25.4 percent in 2010 to 16.1% in 2019. This margin never drops below the Midwest ISO system Planning Reserve Margin of 15.4 percent established for the 2010-2011 planning year."

However, in MISO's recently completed "EPA Impact Analysis-Impacts from the EPA Regulations on MISO" dated October 2011 and provided as Exhibit No.___(DJN-1), MISO's current capacity margins and potential capacity margins with potential retirements due to EPA regulations places the MISO System reserve margins between 10.9 percent and 23.3 percent in 2015 when Montana-Dakota's capacity purchase agreement with We Energies expires and dropping to a low of 6.6 percent in 2021. As reflected in MISO's analysis, the impact of potential EPA regulations are causing uncertainty about the future of existing generation resources, particularly coal, which could have a significant impact on reserve margins.

**Q. What is the potential impact of proposed EPA regulations on the MISO market?**

A. In the MISO Study provided in Exhibit No.___(DJN-1), MISO looked at the potential effects of EPA's proposed regulations for:

a. Cooling Water Intake Structures,
b. Coal Combustion Residuals,
c. Clean Air Transport Rule, and
d. Mercury and Air Toxics Standards.

Combined, MISO estimated these proposed regulations could cause the retirement of 2.9 GW to 12.6 GW of coal-fired generation. Retirements of this level of coal-fired generation will significantly reduce the MISO capacity reserve margins and lead to the construction of new natural gas-fired generation. The net effect is that the cost of purchased capacity will increase sharply and the cost for new natural gas-fired plants will rise faster than inflation due to increased demand.

**Q. Has the uncertainty from pending EPA regulations affected Montana-Dakota's ability to purchase capacity from its previous capacity suppliers?**

A. Yes, one of Montana-Dakota's historical capacity suppliers will not bid anything longer than a one year term because of concerns with what the EPA or other governmental entities could impose regarding environmental regulation in the future. This supplier has not submitted responses to either of Montana-Dakota's last two requests for proposals.

The other recent capacity supplier was only able to offer its wholesale tariff rate in response to the 2010 RFP due to environmental uncertainty.

In short, we believe these uncertainties regarding EPA and other government regulations are limiting the availability of long-term contracts for capacity resources.

## THE 2009 AND 2011 IRPs

**Q. What were the results of Montana-Dakota's modeling in the 2009 Integrated Resource Plan (2009 IRP)?**

A. The EGEAS modeling in the 2009 IRP showed the need for the Big Stone II resource and a 75 MW combustion turbine in 2015. The 75 MW combustion turbine was further studied after the 2009 IRP and the size of the resource was increased to 88 MW.

**Q. What were the results of the EGEAS modeling used in the 2011 IRP?**

A. Montana-Dakota's study activities for the 2011 IRP showed that the construction of an 88 MW combustion turbine near Heskett Station in 2015 was prudent along with investment in the Big Stone AQCS project and the execution of a 25 MW commercial and industrial demand response program.

**Q. Did the modeling activities in the 2011 IRP also show the need for a second combustion turbine to be constructed in 2015?**

A. In all cases, the modeling activities showed the need for multiple combustion turbines in 2015. The Company's plan is to issue another request for proposal in 2012 for its remaining customer demand requirements in 2015. With the addition of the 88 MW combustion turbine, the investment in the Big Stone AQCS project, and the execution of a 25 MW commercial and industrial demand response program; the current projected capacity deficit in 2015 is 36 MWs (6.1 percent of all capacity requirements) as compared to the original 149 MWs of additional capacity requirements in 2015.

## OTHER SUPPLY OPTIONS

### a. A 43 MW Aero-Derivative Combustion Turbine

**Q. On page 22 of his Initial Testimony, Mr. Hahn questioned the Company's modeling of the equivalent forced outage rate (EFOR) for the 43 MW Aero-Derivative Combustion Turbine (43 MW CT). Why**

**did the Company model a 22.31 percent EFOR for the 43 MW CT and did it affect the outcome of the modeling?**

A. The 22.31 percent EFOR[1] for the 43 MW CT represents a published MISO average forced outage rate for turbines of that size and class. This was a conservative approach that was applied in the same manner as a similar MISO average forced outage factor for the 88 MW CT.

In response to a request by La Capra, the Company produced a model with the EFOR for the 43 MW CT reduced to 6.45 percent. This change in the EFOR did not cause the model to select the 43 MW CT over the 88 MW CT in 2015, as shown in Summary of Additional EGEAS cases provided in Exhibit No.__(DJN-2).

**Q. Why does the Company's EGEAS model select such a high number of 43 MW CTs in the sensitivity analysis as noted by Mr. Hahn on Page 38 of his Initial Testimony?**

A. The EGEAS model selects an economic balance of low-cost capacity and high efficiency generation resources that complement Montana-Dakota's system, which relies heavily on low-cost coal-fired generation units. The 43 MW CT provides the best solution, after the 88 MW CT in 2015, for meeting both the energy and capacity requirements as compared to a higher cost combined cycle generating unit or a lower cost and less efficient frame type generating resource. Small coal or

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[1] MISO 2011-2012 Pooled EFORd Class Average, https://www.midwestiso.org/Library/Repository/Report/Resource%20Adequacy/2011%20-%202012%20Pooled%20Class%20EFORd%20Table.pdf.

integrated gasification combined cycle units are too expensive as compared to natural gas generation to warrant consideration.

**Q. Is the ADP and CPCN application requesting approval to build all of the future combustion turbines identified in the Company's resource plan?**

A. No, at this time the Company is only seeking to construct one 88 MW CT in 2015 which is selected by all of Montana-Dakota's modeling runs. As indicated previously, the Company's plan is to issue another request for proposal in 2012 for its remaining 36 MWs (6.1 percent of all capacity requirements) of customer demand requirements as compared to the original 149 MWs of capacity requirements in 2015.

**b. A Wind Resource**

**Q. How did Montana-Dakota model wind resource alternatives in the EGEAS runs for the 2011 IRP?**

A. The Company modeled wind resource alternatives in the 2011 IRP as either a power purchase agreement or a self-build resource. The pricing for the power purchase agreement alternative came from a proposal received in the 2010 RFP. The proposal was for a wind generation project that is already constructed and connected to the Company's transmission system. Accordingly, the Company viewed this is an accurate reflection of pricing for such a power purchase agreement.

The pricing for the self-build wind option was based on the Company's experience with its Diamond Willow and Cedar Hills wind projects.

**Q. What is the effect of the inclusion of the fixed O&M component for the purchased wind energy proposal as Mr. Hahn described on Page 23 of his Initial Testimony?**

A. The Company originally modeled the purchased wind proposal as a capacity and energy resource as bid in the 2010 RFP. A capacity credit was modeled with a number of available PRCs (MISO capacity credits) from the proposal along with a fixed O&M cost to represent the cost of this purchased capacity. The EGEAS modeling did not pick this configuration as a least cost resource. The Company then modeled this wind proposal as an energy only project by removing the available PRCs and making the energy available in either 2015 or 2020, however, the fixed O&M cost was not removed as should have been done to model this resource as an energy only resource.

Removal of the fixed O&M cost associated with the wind proposal in a follow-up EGEAS run requested by La Capra did not cause the purchased wind proposal to be selected as an energy resource, as shown in Exhibit No.___(DJN-2).

**Q. What is the effect on the EGEAS model if the cost of self-built wind is reduced to $1,750 per kW?**

A. Reducing the installed cost of wind generation to $1,750 per kW, coupled with the extension of the Federal PTC, will cause the EGEAS model to select self-built wind generation to meet the Company's future energy requirements and combustion turbines like the 88 MW Heskett CT to meet its capacity requirements.

Montana-Dakota, however, does not agree that $1,750 per kW is a realistic long-term cost estimate for wind generation. The current cost of wind generation is depressed due to a lack of demand and the availability of pre-purchased wind turbine equipment for sale in the market. When the market for pre-purchased wind turbines is evaporated and/or demand increases, the price for installed wind turbine will likely rise to pre-2010 levels.

**Q. On page 41 of his Initial Testimony, Mr. Hahn indicates that if the Company had included in its modeling a ND wind project that was bid into the 2010 RFP, the model would not have selected the 88 MW combustion turbine. Describe the ND wind project and why it was not included in the modeling.**

**A.** The ND wind project that was bid in response to the 2010 RFP was for a new 150 MW wind project to be located near Hettinger, North Dakota (ND Proposal). At the time the 2010 RFP screening runs were performed, the ND Proposal was part of a System Impact Study that MISO was performing for several new wind generator interconnection requests in the area. The amount of system network upgrades assigned to the ND Proposal was **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**. The inclusion of these system network upgrade costs would have made the ND Proposal more expensive than other similar projects included in the 2010 RFP screening runs, including the previously described fully constructed and on-line wind project which was included for modeling.

If Montana-Dakota were the off-taker for the ND Proposal, the Company would have to take out a transmission service request with WAPA as the Company does not have sufficient transmission capacity in the Hettinger area to move all of the energy to Montana-Dakota's customer load. This would also increase the cost of the ND Proposal by as much as $4.80 per MWh (in 2011 dollars).

**Q. On Page 27 of his Initial Testimony, Mr. Hahn states that the Company should have considered the lower network upgrade costs in the January 13, 2011 report for the Company's analysis of the ND Proposal. How was this information considered?**

A. On January 13, 2011, MISO released its "Montana and North Dakota DPP Cycle 5 Definitive Planning Phase" report that reduced the level of required transmission system network upgrades for the ND Proposal to $22.9 million. Even after this release in January 2011, Montana-Dakota still had concerns with the costs associated with the network upgrades for the ND Proposal and its dependence on flows on the WAPA transmission system. WAPA has taken a firm position with MISO utilities in the area that if a sufficient MISO transmission path cannot be shown for a wind generator that resource must take transmission service from the WAPA IS Tariff.

The Company believed that the purchased wind energy proposal in the EGEAS model for the 2011 IRP was an accurate and better representation of the current market price for a wind resource because that resource was already constructed, online, and had sufficient MISO transmission available for its use. Montana-Dakota's concerns with the ND Proposal made it riskier and more expensive than the purchased wind energy proposal in the 2011 IRP which was not selected as a least cost resource.

**Q. Would the inclusion of the ND Proposal have affected the EGEAS model selection of the 88 MW CT as a least cost resource?**

A. No, the ND Proposal is an energy only resource and does not support the Company's capacity needs. In fact, the selection of the ND Proposal in the EGEAS model as an energy resource would bias the model to select the 88 MW CT, because of its lower capacity cost, over the 43 MW CT and the 140 MW CCCT.

**Q. What would be the effect if Montana-Dakota would add 150 MW of purchased wind into its resource supply mix?**

A. Adding 150 MW of purchased wind generation would quadruple the amount of Montana-Dakota's wind generation and likely cause the Company to consider shutting down its smaller coal plants during the spring and fall months when customer loads would frequently be less than on-line generation (wind generation plus coal-fired generation at minimum load). Other utilities in the area have had to resort to this strategy in recent years. Moreover, wind generation is predominately an energy resource and selection of a wind resource does not change the need for capacity by the Company. The EGEAS model will continue to select combustion turbines like the 88 MW Heskett CT to meet the Company's capacity requirements with or without the addition of a wind resource.

**Q. How did the Company model the expiration or extension of the Federal Production Tax Credit (PTC) for wind generation beyond 2012?**

A. Montana-Dakota modeled the PTC to expire at the end of 2012 without extension for the self build wind generation resource. With current federal budget constraints it seems likely that if the PTC is extended, it will likely be at a reduced funding level.

The modeled wind purchased resource, however, is already online and its pricing includes the benefits of the existing PTC.

**c. A Combined Cycle Combustion Turbine Resource**

**Q. What is the effect of the discrepancy in the modeled cost of the 140 MW combined cycle combustion turbine (CCCT) that Mr. Hahn discussed on Pages 24 and 25 of his Initial Testimony?**

A. As Mr. Hahn indicated in his Initial Testimony, the Company improperly modeled the incremental cost of the 140 MW CCCT in the EGEAS runs developed for the 2011 IRP and used a value developed as part of the 2009 IRP. Montana-Dakota adjusted the incremental cost for the 140 MW CCCT in a follow-up EGEAS run to the 2011 IRP and there was no change in the model results.

**Q. Does the incremental method used to model the combined cycle resource bias the model towards the 88 MW CT as Mr. Hahn suggests on Page 25 of his Initial Testimony?**

A. No, if properly priced the decision to add or not add the combined cycle addition is based purely on economics. The model can add both the 88 MW and the incremental 140 MW CCCT resource in the same year. The net effect would be the addition of a 140 CCCT MW resource at $1,150 per kW (or $1,300 per kW as modeled in the 2011 IRP). Montana-Dakota believes that this modeling strategy for the CCCT provides economic options and does not create a selection bias towards the 88 MW CT. The model is not picking the CCCT option at this time because the incremental cost is adding an energy resource while the Company's primary need at this time is for capacity. The selection of the 88 MW CT at this time makes the availability of the CCCT in combination with the CT more economical as a future energy resource.

**Q. Why did the Company allow the selection of only one 140 MW CCCT unit in the EGEAS modeling used in the 2011 IRP?**

A. The EGEAS model did not select one 140 MW CCCT unit, therefore there is no need to make more than one 140 MW CCCT available. If more than one 140 MW CCCT option was available, it would increase the solution time as the model has more options to consider. If the model did select one 140 MW CCCT, then the Company would increase the number of 140 MW CCCT resources available in the model to determine if a second CCCT resource would be selected.

**d. The Calpine Proposal**

**Q. Would changing the energy price for the Calpine proposal from** [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, as suggested by Mr. Hahn on Page 26 of his Initial Testimony, change the EGEAS modeling results for the Calpine resource?**

A. No, the Calpine proposal is primarily a capacity resource, similar to the 88 MW CT, and there are other energy resources in the EGEAS model that will dispatch first at a lower cost per MWh than the Calpine proposal.

**e. The Illinois Proposal**

**Q. Please describe the Illinois Proposal.**

A. Montana-Dakota issued Request for Proposals on June 1, 2010 (2010 RFP) seeking proposals for generation resources. One of these proposals submitted in response to the 2010 RFP was from an existing 176 MW simple cycle combustion turbine (SCCT) project located along the Illinois and Indiana boarder (IL Proposal).

**Q. Was the IL Proposal included in the screening runs for the 2010 RFP?**

A. The IL Proposal was not included in the screening runs for the 2010 RFP because of its physical location on the eastern side of MISO, located along the border of Illinois and Indiana. At the time of the EGEAS screening runs for the 2010 RFP in September of 2010, MISO was working with stakeholders through several issues on a new capacity market (resource adequacy) construct initiative. Changes to the capacity market and system reserve requirements discussed by stakeholders included the development of a mandatory annual capacity auction and the development of local resource zones (LRZs) for studying capacity deliverability within the MISO footprint. Concerns with the long-term ability to deliver capacity and energy from the IL Proposal to Montana-Dakota's customers caused the Company to not include the IL Proposal in the initial EGEAS screening runs for the 2010 RFP.

**Q. Did the Company include the IL Proposal into subsequent EGEAS modeling runs for the 2010 RFP?**

A. Yes, the proposal was included, as bid, in a post screening EGEAS run to see if it would be selected as a least cost resource. As bid, the proposal was selected as a least cost resource. No adjustments were made in the EGEAS modeling assumptions for the IL Proposal related to the deliverability issues that the Company had with this resource.

**Q. What is your response to the characterizations that Mr. Hahn makes in his Initial Testimony regarding the ability of Montana-Dakota to utilize the IL Proposal as part of MISO's new resource adequacy construct?**

A. Mr. Hahn, on Page 30 of his Initial Testimony, implies that the self-scheduling option in MISO's Resource Adequacy Construct would fully hedge any pricing differences between local resource zones (LRZs) if Montana-Dakota would try to use the capacity from an IL resource in LRZ

#4 to meet the Company's load obligations in LRZ #1 (See Figure 1). This is incorrect as the "self-scheduling" and "opt-out" options only work for generation and load located in the same LRZ or which has dedicated transmission between LRZs.

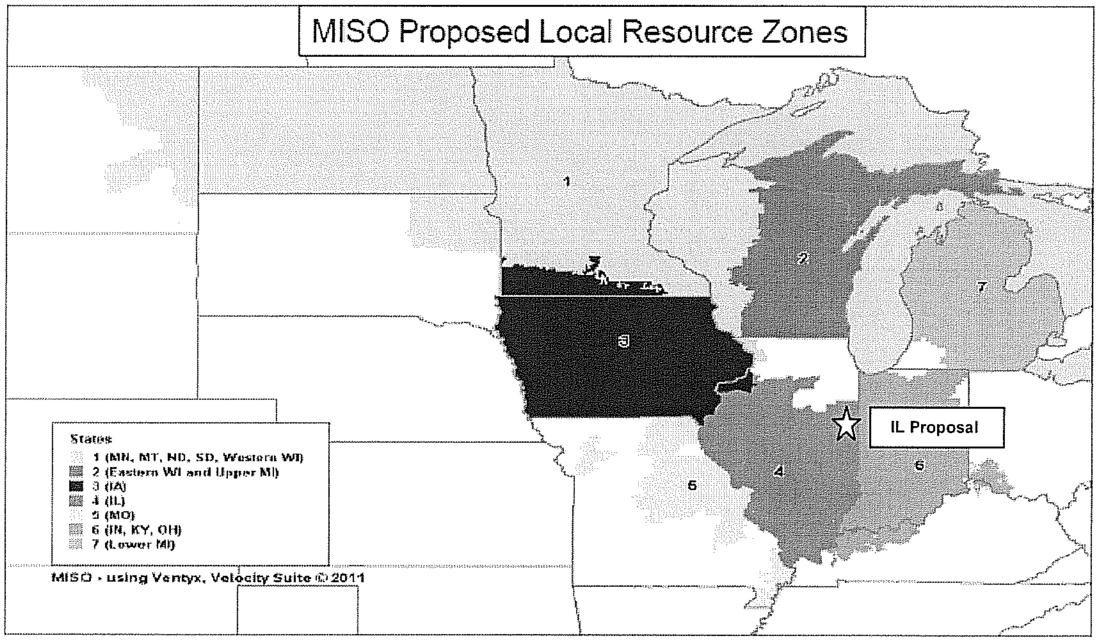



Figure 1

**Q. What are the hedging mechanisms in MISO's new resource adequacy construct?**

A. Load-serving entities (LSE) like Montana-Dakota, can "opt-out" of the annual capacity auction if they have dedicated transmission between LRZs and/or "self-schedule" if their load and capacity resources are located within the same LRZ. Excess capacity or load deficiencies would be subjected to the annual auction.

**Q. Would "self-scheduling" and "opt-out" apply to the IL Proposal?**

A. No. Montana-Dakota's load is located within LRZ #1 and the IL Proposal is located within LRZ #4. Montana-Dakota does not have a transmission path between the IL Proposal and its pricing zone.

**Q. What happens when excess capacity in an LRZ goes to zero?**

A. If sufficient capacity is not available within an LRZ, the LSE would be subjected to the cost of new entry (CONE) penalty which is currently $95,000 per MW-year.

**Q. What is the financial risk if Montana-Dakota tried to use capacity (PRCs) from LRZ #4 to meet load obligations in LRZ #1?**

A. Under MISO's new resource adequacy construct, MISO will annually study the amount of load requirements needed and capacity resources available in each LRZ. Next, MISO will determine the transfer capability of PRCs between neighboring LRZs.

The IL Proposal is not located in a neighboring LRZ but is located two LRZs away from Montana-Dakota's LRZ. If sufficient transfer capability does not exist between LRZ #1 and LRZ #3, and between LRZ #3 and LRZ #4, then Montana-Dakota may not be able to fully utilize the PRCs from the IL Proposal that it purchased.

**Q. What could be the dollar spread between PRCs in IL and PRCs in ND as part of MISO's annual energy auction?**

A. A worst case scenario would be where a) LRZ #1 is deficient capacity resources and the MISO Auction prices of PRCs in LRZ #1 would be the cost of new entry (CONE) and b) LRZ #4 would have excess PRCs and the auction price for PRCs in LRZ#4 would be zero. In this situation the PRCs from the IL Proposal would have no value to Montana-Dakota's customers and Montana-Dakota would be required to purchase additional PRCs from the MISO Auction at CONE.

**Q. Do you see this as a probable scenario?**

A. I believe that this is not a highly probable scenario but the situation does exist given the economic development occurring in LRZ#1. With the twenty year term of the IL Proposal, it is impossible to presume that things will work smoothly over the entire term of the agreement.

**Q. How does MISO's recently approved 2011 Candidate Multi-Value Projects (2011 MVP) affect the ability to move capacity from Illinois to North Dakota?**

A. The 2011 MVPs are not forecasted to be completed until at least 2019, which is five years into the term of the IL Proposal. The 2011 MVPs only bring transmission to the eastern edge of Montana-Dakota's service territory at Ellendale, North Dakota (see Figure 2).

**MISO 2011 Candidate Multi-Value Projects**

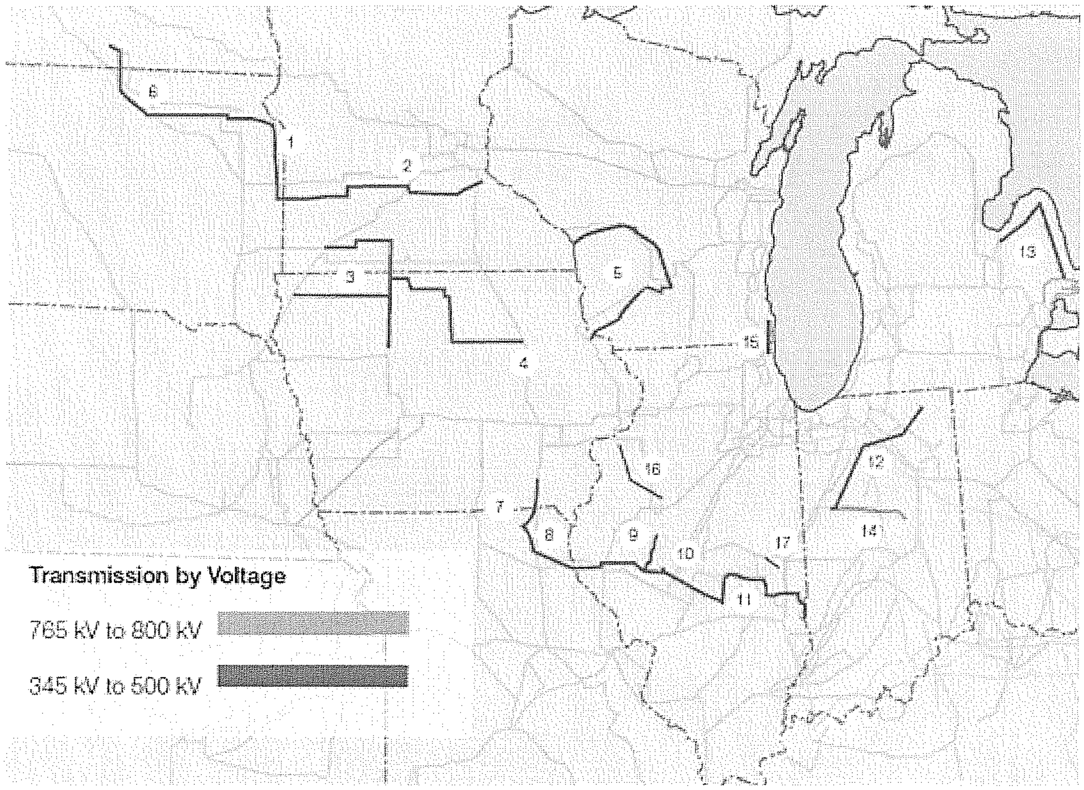



Figure 2

The 2011 MVPs in the central and eastern regions of MISO are designed to address congestion in the on-peak case while the MVPs in the western region of MISO address off-peak constraints.

Congestion exists throughout the MISO footprint, as seen in Figure 3 which is a chart from MISO's 2011 Top Congested Flowgate Study.

**Top Congested Flowgates in PROMOD Run**

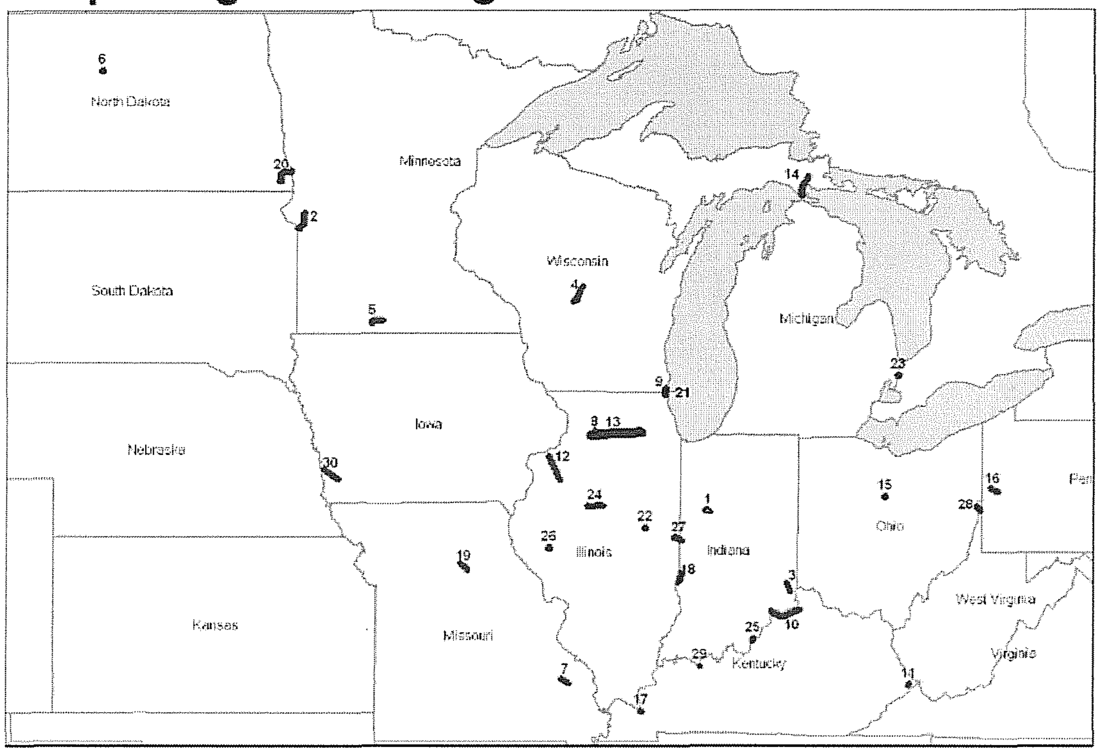



Figure 3

It is overly simplistic to assume that the 2011 MVPs will alleviate all congestion between Illinois and North Dakota and that Montana-Dakota should not be concerned with the ability to utilize PRCs from the IL Proposal to meet its load serving requirements in Montana, North Dakota, and South Dakota. Furthermore, while the MVP Portfolio was recently adopted by the MISO Board, the cost allocation treatment for the MVPs is currently in front of the Seventh Circuit Court of Appeals and the 2011 MVP portfolio is likely to be challenged by several states and stakeholders in the federal court system as well.

**Q. What other factors could affect the ability to use a capacity resource from Illinois?**

A. Changes in MISO membership, whether that is Montana-Dakota or others, could impact the ability to utilize capacity from Illinois. For example, Montana-Dakota's only connection to MISO is contingent upon Otter Tail Power Company's (Otter Tail) continuation as a MISO member. If either Montana-Dakota or Otter Tail were to withdraw from MISO, Montana-Dakota would be required to secure a transmission service request, if available and if economic, to show deliverability of the capacity resource from Illinois to North Dakota to utilize capacity from an Illinois resource.

Just a year ago, any network resource in MISO was fully deliverable across the footprint for capacity obligation purposes. MISO's new resource adequacy construct recognizes that capacity is not universally deliverable and congestion and transfer capabilities across the MISO footprint must be considered. There is no guarantee that the MISO tariff will not change again within the next twenty years which could adversely affect the ability of Montana-Dakota to use capacity from the IL Proposal.

**Q. Is the IL Proposal deliverable to Montana-Dakota's local balancing authority?**

A. No, the use of the capacity credits from the IL Proposal is a paper transaction without the ability to physically deliver the energy to Montana-Dakota. Therefore, the contract will provide no reliability benefits to Montana-Dakota's system.

**Q. Does Montana-Dakota currently have any power purchase agreements from third parties outside of its local resource zone (LRZ)?**

A. Yes, the We Energies purchased power agreement is outside of LRZ #1.

**Q. What concerns does Montana-Dakota have with this power purchase agreement?**

A. This agreement was entered into with We Energies in 2009 and was intended to replace the NSP purchased power agreement which ends in 2011. This agreement will be used to meet Montana-Dakota's capacity resource requirements. Prior to entering into the agreement, Montana-Dakota was concerned with the ability to use this resource for capacity obligations without a transmission service request. After reviews of the MISO tariff and conversations with MISO, Montana-Dakota was comfortable that it could use the capacity without a transmission service request although the ability to move the energy back to Montana-Dakota's pricing zone would incur congestion costs. Because this agreement was entered into prior to 2011, the capacity credits will be exempt from the annual LRZ transportability restrictions.

**Q. How do system constraints affect movement of energy from the western regions of MISO to the east?**

A. Congestion exists throughout the MISO footprint, see Figure 3, and is not strictly a problem between Illinois and Iowa as Mr. Hahn indicates on Page 29 of his Initial Testimony. For example, constraints to the east of the Big Stone Plant frequently affect the pricing for the Big Stone pricing node. The construction of MISO 2011 Candidate MVPs will likely move current congestion on the system to new points of constraints.

**Q. Please describe the results from the additional EGEAS modeling runs that the Company performed that are included in Exhibit RSH-6 of Mr. Hahn's Initial Testimony and Confidential Exhibit No. ___(DJN-3) of your Rebuttal Testimony.**

A. In La Capra Data Request Set 3, the Company was requested to perform additional EGEAS modeling runs using the Base Case from the 2011 IRP to account for various discrepancies and requests that Mr. Hahn described in his Initial Testimony on Page 40. The following is a summary of those changes made to the 2011 IRP Base Case model.

- Included two additional responses from the 2010 RFP to be considered as resource alternatives:
  - 150 MW North Dakota wind proposal (ND Proposal)
  - 176 MW Illinois combustion turbine proposal (IL Proposal)
- Lowered the forced outage rate for the 43 MW Combustion Turbine from 22.31 percent to 6.45 percent
- Lowered the capital cost for the self-built wind options from $2,400/kW to $1,750/kW
- Assumed the federal production credit was extended through 2020 as compared to 2012
- Set the fixed O&M for the purchased wind energy option to $0 from $12/kW-yr

- Lowered the variable O&M for the self-built combined cycle option to $3.00/MWh from $6.00/MWh

Mr. Hahn also requested the Company remove the Keystone XL pipeline load from the demand and energy forecast used in the EGEAS model. The Company indicated in a response to La Capra Data Request 3-3 that the Keystone XL Pipeline load was not removed from the additional EGEAS models. This would have required a large amount of work and the removal of the Keystone XL Pipeline load falls within the Low Growth scenario. Also, the Company's load forecast for 2012-2031 will likely contain enough additional new growth to make-up for any loss or delay of the Keystone XL Pipeline.

The results of the La Capra Modified Base (Additional Case 1) provided in Exhibit No.__(DJN-2) page 2 showed that the IL Proposal, as originally bid, was selected to meet the Company's demand requirement in 2015 and the ND Proposal was selected to meet the Company's future energy requirements in 2015. Removal of the IL Proposal and ND Proposal from the La Capra Modified Base (Additional Case 2) showed that the resource selections in 2015 delayed the installation of one 43 MW CT by two years and continued to select the 88 MW Heskett CT as a least cost resource.

**Q. Do you agree with Mr. Hahn's usage of the additional EGEAS modeling runs to quantify the dollar value difference between the IL**

**Proposal and the Company's 88 MW CT proposal on Page 41 of his Initial Testimony?**

A. No. The EGEAS model is not a good measure of the relative dollar value difference between the IL Proposal and the 88 MW Heskett CT in this situation. The model does not account for the reliability benefits of locating an 88 MW CT at Heskett Station or any potential difference in zonal capacity prices between LRZ #1 and LRZ #4. The EGEAS model chooses future resource additions over a 20 year study period and then extends those costs out for an additional 30 years. This is done so that if a large capital resource is selected in year 20, the model will depreciate its costs and spread its benefits over the next 30 years and not bias the model into delaying high capital cost resources beyond the 20 year study period.

In the EGEAS model, the IL Proposal was modeled as a 20 year power purchase power agreement. The expiration of the 20 year power purchase agreement occurs after the 20 year study period and the model assumes that a similar sized and priced resource will be available through the 50 year modeled timeframe. This is not the case as it would effectively mean that the IL Proposal is a 45 year agreement (selected in Year 5) with flat (no escalation) Capacity and Fixed O&M pricing.

**Q. Have you had a chance to review to review the side-by-side comparison that Mr. Hahn developed in his Confidential Exhibit RSH-7 and described on Page 42 of his Initial Testimony?**

A. Yes, I have and I would say that the cost differential is over stated by Mr. Hahn for several reasons. First, the Company is only requesting to construct one 88 MW CT while Mr. Hahn's analysis assumes that the Company is constructing two 88 MW CTs. Second, the energy from the IL Proposal is not deliverable without incurring congestion costs and should be considered a capacity only resource. This would remove the Variable O&M and Fuel Costs from the analysis. Third, the proposed term of the IL Proposal is 20 years and not 16 years as Mr. Hahn uses in his analysis. Lastly, with the expiration of the Western Area Power Administration (WAPA) Transmission Service Agreement on December 31, 2015, Montana-Dakota will be required to take additional network transmission service from the WAPA Integrated Transmission System (IS) for loads that the Company is unable to service without support from the IS. A generating resource at Heskett Station would help ensure that the Company has sufficient transmission and generating resource available to serve all customer load and deliverability requirements east of Beulah, North Dakota. The reliability and monetary benefit of having an 88 MW combustion turbine at Heskett Station is the potential avoidance of annually paying $3.12 million (in 2011 dollars) to the WAPA IS.

As shown in Confidential Exhibit No.__(DJN-3) with the above described changes, the 88 MW CT, including AFUDC, is less expensive than the IL Proposal on a total expenditures basis and only **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** more expensive on a net present value basis.

On a side-by-side comparison basis, the 88 MW CT should be considered a prudent resource addition for the technical and economic reasons described here and in Andrea Stomberg's Rebuttal Testimony.

## OTHER CONCERNS

**Q. How does the Company account for AFUDC in its EGEAS modeling?**

A. The installed cost for self-built supply side resources is assumed to contain AFUDC. Otherwise the EGEAS model would have to account for cash flow, construction schedules, and financing.

The detailed cost build-up for the 88 MW Heskett CT in the 2011 IRP did not contain AFUDC. Further refinements for the estimate of the 88 MW CT included adding AFUDC, removing the SCR requirement, and increasing the natural gas pipeline costs. These refinements were included in the application for the ADP and CPCN in this proceeding. The updated cost of the 88 MW Heskett CT in the ADP and CPCN filing fell within the modeling costs, assumptions, and scenarios used in the 2011 IRP.

**Q. Have you reviewed Mr. Hahn's Initial Testimony on Page 38 where he states "the modeling may have been biased toward building new peaking capacity and not units that produce significant amounts of energy" and how would you respond?**

A. I do not think that the modeling is biased, but it responds to a situation where the Company has few options to economically meet both the demand and energy growth requirements that are forecasted for the

Company. In 2009, the Company's IRP model picked capacity and energy from a large coal-fired generating project as least cost. That alternative is not available today and with the uncertainty surrounding coal-fired generation there are few options besides simple cycle generation resources. Combined cycle projects are too expensive today as compared to efficient combustion turbine technology in this r region. The forecasted low runtime on a combined cycle generating plant does not justify the additional cost.

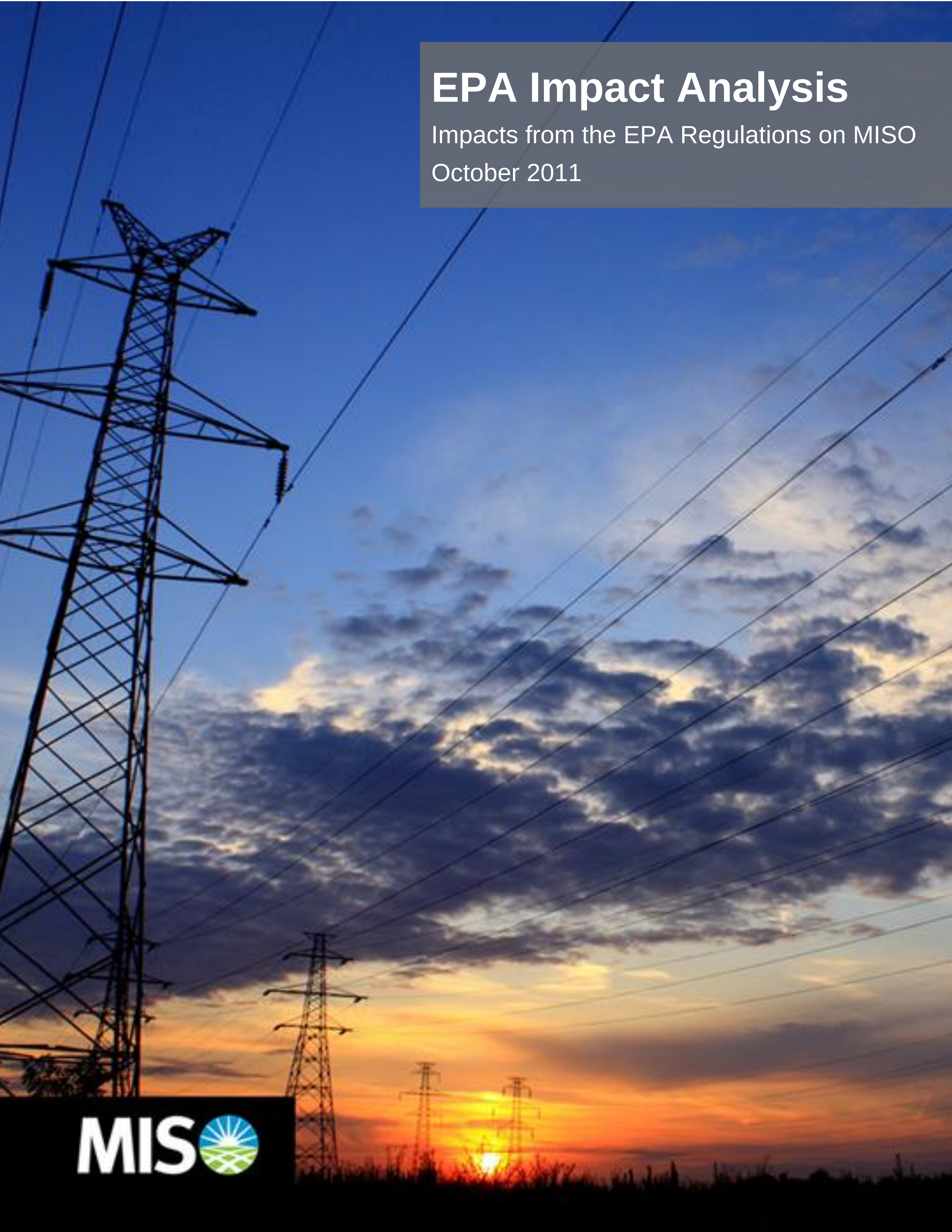
**Q. On Page 39 of his Initial Testimony, Mr. Hahn states the Company did not consider two important scenarios in its sensitivity analysis (1) high coal retirements in MISO and (2) renewal of wind PTCs. How would the model respond to these two scenarios?**

A. A high coal retirement scenario will cause market energy prices to rise as natural-fired generation will set the marginal energy price a higher percentage of the time. A high coal retirement scenario will also cause a reduction in the excess capacity market in MISO and the cost of purchased capacity will approach the cost of a new simple cycle unit. The EGEAS model will probably look more favorably at the installation of some level of combined cycle generation to replace the retired coal generation, which requires the 88 MW CT addition.

If the Federal PTC incentive for renewable generation is extended, the MISO energy prices will remain low during off-peak periods which will bias the market towards simple cycle combustion turbines. In this scenario, a future baseload resource would look like the combination of wind turbines and simple cycle generating units which also supports the installation of the 88 MW CT.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.



# EPA Impact Analysis

Impacts from the EPA Regulations on MISO

October 2011

## Contents

# 1. Study disclaimer

The objective of the MISO EPA Regulation Impact Analysis is to inform stakeholders. MISO has no intention or authority to direct generation unit strategies as that authority belongs exclusively to the individual asset owners. The MISO analysis provides an overview of the impacts from the MISO regional perspective. Any sub regional evaluation of the data would be an incorrect interpretation and application of the results.

The detailed results of the analysis were derived from a limited set of economic assumptions that included low demand and energy growth, low gas prices and variation of carbon prices with sensitivities performed on gas and carbon prices. Retirement impacts can change with different assumptions for these variables. The study also assumes that the natural gas Transmission System is sufficient to accommodate the increased dependence on the natural gas fleet. This addresses some of those issues, but can't capture all future outcomes. To better understand the affects of changing inputs and risks of the uncertainty of carbon, additional analysis needs to be performed.

An additional caveat - since completion of this analysis - the EPA finalized the Cross State Air Pollution Rule (CSAPR). In general, the final regulation mandated more restrictive emission limits for some states than was modeled in this analysis. The final CSAPR has stronger state limitations in most cases but allows for a national trading program, which may allow for more flexibility in meeting the limits. In general, the rule appears to have the greatest impact in the near-term (1-3 years) operation of the generation fleet due to the reduction in the number and availability of both $SO_2$ and $NO_X$ allowances. The magnitude of this change on the MISO system is being evaluated in a follow-up study.

The EPA Regulation Impact Analysis was based on assumptions for *proposed* EPA regulations. Finalization of the remaining three regulations has the potential to introduce the risk of additional change and uncertainty, similar to what occurred with the CSAPR regulation. Any of the final regulations could differ from what was modeled in this analysis.

# 2. Executive summary

Over the last two years the U.S. Environmental Protection Agency (EPA) issued four proposed regulations that will affect the MISO system. One of the rules was finalized in July while the other three are still in draft form. The regulations will impact unit operations in the near-term (1-3 years) in addition to requiring utilities to retrofit their generators with environmental controls or retire them in the 2015 timeframe. At the direction of its members, stakeholders and Board of Directors, MISO evaluated the impacts of the new regulations, including carbon requirements. This study evaluated the impacts on capacity cost, Resource Adequacy, cost of energy and transmission reliability.

MISO evaluated the four proposed regulations separately and in combination with each other over a nine month study period. This report focuses on the four rules as they were developed in draft form. The impact of the finalized Clean Air Transport Rule/Cross State Air Pollution Rule will be undertaken in an exhaustive follow-on study that is currently underway.

The four proposed regulations are:

- Cooling Water Intake Structures (CWIS) – section 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS), formerly known as EGU Maximum Achievable Control Technology (MACT).

## 2.1 EPA impact results summary

A survey of MISO's current fleet revealed that a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs outweigh the benefits of continued operation. Figure 2.1-1 shows that there are 298 coal units affected by these four proposed regulations and that the majority of the units (63 percent) are affected by three or all four regulations.

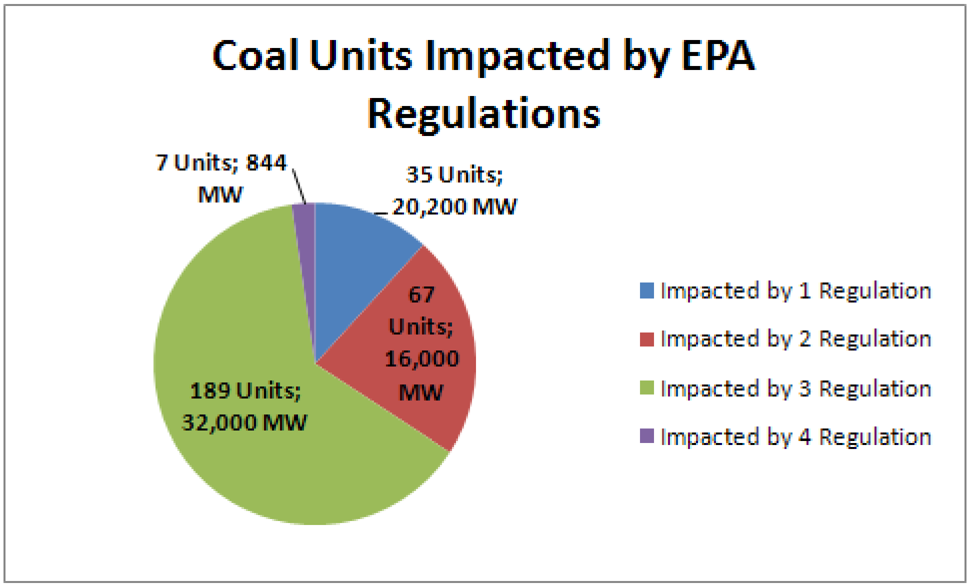



**Figure 2.1-1: Number of units affected by EPA regulations**

The studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) commonly used by utility generation planners. MISO performed more than 400 sensitivity screens using the EGEAS capacity expansion model to identify the units most at-risk for retirement. The sensitivities consisted of variation in costs for natural gas, cost uncertainty risk and retrofit compliance.

MISO identified nearly 13,000 MW of units at risk for retirement. Those units were offered to the EGEAS model as an economic choice to retrofit for compliance or retirement. The model makes this decision by comparing alternatives and selecting an expansion forecast that minimizes costs, capital investment, production, emissions and annual fixed operations and maintenance.

MISO ran two economic alternatives. The first evaluated a $4.50 natural gas cost, compliance for all the identified regulations and an expected cost for compliance with the regulations based on MISO stakeholder feedback through the study process. The second analysis evaluated increased compliance costs on the system. These increased costs are represented through a production cost adder coupled with the production of carbon on the system and is proxy for costs associated with the uncertainty around rules not finalized, additional life extension costs needed for balance of plant as well as the considered risk around the uncertainty of the treatment of green-house gases. It is expected that one or all are within the assumption error bounds for this analysis and the impacts will be considered in the fleet strategies of the asset owners. The results of the EGEAS analysis produced:

- **2,919 MW** of coal fleet capacity at-risk for retirement under all likely scenarios. As of the publishing of this study, retirement requests of the coal fleet have amounted to 2,500 MW in the MISO Attachment Y process.
- **12,652 MW** of coal fleet capacity at-risk for retirement identified to be within prudence considerations and error bounds for the assumptions of the MISO study.

The EGEAS retirement analysis minimizes the total system net present value costs over a twenty year planning period plus a forty year extension period. When the 2,919 MW and 12,652 MW of retired capacity were forced into the model, it was shown that the overall net present value of system costs varied by approximately 1 percent. This value is within the tolerance of assumption error. Additionally, MISO did not consider unit life extension costs in its evaluation. Because of these two considerations, it is expected that the higher value of nearly 13,000 MW is more realistic of the potential retirements on the system.

Using a suite of planning products, MISO's evaluation on the range of potential impacts indicates the following:

- Total 20-year net present value capital cost of compliance may range from **$31.6 billion** for 2,919 MW of retirement to **$33.0 billion** for 12,652 MW of retirement. Both values are in 2011 dollars and include the cost of retrofits on the system, replacement capacity, fixed operations and maintenance and transmission upgrades. The perceived balance in total system capital investment occurs because the average cost for installation of control technologies for a unit is approximately equivalent to the cost of a new combustion turbine that represents an alternative solution to compliance with the rules.
    - Capital costs for retrofits are **$28.2 billion and $22.5 billion**, respectively.
    - Maintenance of the Planning Reserve Margin (PRM) is obligated under the MISO tariff. So it is expected that any capacity retirements would eventually be matched with replacement capacity to support PRM requirements. To maintain this requirement, it is estimated that the replacement costs would be **$1.7 billion and $9.6 billion.**
    - The bulk of the capital investment for the generation fleet is expected to occur in the 2014/2015 time frame to meet 2015/2016 requirements established through the proposed MATS regulation. This includes potential need for replacement resources as 12,652 MW of capacity retirements would erode the current installed reserves to below planning reserve margin values by 6 to 7 percentage points, Table 2.1-1.

- The annual fixed operations and maintenance affects the cost by **$1.1 billion and $0.0**, respectively.
- Retirement of units will have an impact on localized Transmission System reliability. To ensure voltage and transmission thermal support on the system, an estimated **$580 million and $880 million**, respectively, of additional transmission upgrades could be necessary to maintain system reliability. The transmission numbers depend on location and any change from the study assumptions could result in different costs. This assumes that no replacement capacity is at the retired units. If it is, the transmission upgrade costs will likely decrease.

- By replacing traditionally less reliable capacity with new resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by having a more reliable fleet. Loss of Load Expectation (LOLE) analysis showed reductions of **0.2 to 1.0 percent**. However, if no replacement capacity is identified for Resource Adequacy purposes, then analysis shows that the LOLE on the system could be on the order of **0.21 to 1.028 days/year**. The current target is 0.1 days/year.
- There will also be an increase in the MISO load-weighted LMP of between **$1.2/MWh-$4.8/MWh** (2011 dollars). This is driven by two key factors: (1) newly retrofitted units are less efficient because of the emission controls, and (2) retired coal facilities are replaced with natural gas fired capacity resulting in a greater dependence on the higher cost energy.
- Identifying all the costs to maintain regulation compliance and system reliability, retail rates could increase **7.0 to 7.6 percent**.

| | | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| No retirements | Reserve Margin (MW) | 23,930 | 22,438 | 22,064 | 21,368 | 20,760 | 20,065 | 19,287 | 19,950 | 19,031 | 18,032 |
| | Reserve Margin (percent) | 27.0% | 24.8% | 24.2% | 23.3% | 22.5% | 21.5% | 20.5% | 21.0% | 19.9% | 18.6% |
| 2.9 GW Retirements (impacts adjusted for expected derates) | Reserve Margin (MW) | 21,603 | 20,111 | 19,737 | 19,041 | 18,433 | 17,738 | 16,960 | 17,623 | 16,704 | 15,705 |
| | Reserve Margin (percent) | 24.3% | 22.2% | 21.7% | 20.8% | 19.9% | 19.0% | 18.1% | 18.6% | 17.5% | 16.2% |
| 12.6 GW Retirements (impacts adjusted for expected derates) | Reserve Margin (MW) | 12,544 | 11,052 | 10,678 | 9,982 | 9,374 | 8,679 | 7,901 | 8,564 | 7,645 | 6,646 |
| | Reserve Margin (percent) | 14.1% | 12.2% | 11.7% | 10.9% | 10.1% | 9.3% | 8.4% | 9.0% | 8.0% | 6.6% |

**Table 2.1-1 Potential system reserve margin impacts of retirements compared to the MISO 2011 Long Term Resource Assessment**

The generation capacity cost components include both the costs to retrofit and to build new capacity to eventually replace that which is retired. From the previous information, this twenty year net present value cost for 12,652 MW of retirement is approximately $32.1 billion. Table 2.1-2 shows where those costs are incurred in reference to the fleet to meet the proposed regulations. The investment identified is expected to occur prior to implementation of the MATS regulation and the lead time for the addition of control technology or new resources will include planning, regulatory approval, engineering, procurement, construction and installation that may require three to five years to implement on the system.

| Technology | Impacted Capacity (MW) | Average Costs ($/kW) |
|---|---|---|
| No Action Required | 9,569 | 0 |
| Require Fabric Filters (Baghouse) | 27,921 | 150 |
| Require DSI and ACI or FGD | 20,427 | 478 |
| Replacement Greenfield Combustion Turbine Capacity for Retirement | 12,652 | 663 |

**Table 2.1-2 Average overnight construction costs to comply with the proposed regulations.**

There is a compliance risk with the proposed regulations. Additional investment in the generation fleet and the Transmission System will maintain bulk power system reliability – at a cost. However, another risk not addressed directly that must be recognized is the time in which units must be compliant. Figure 2.1- demonstrates a high level timetable of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take at least two to three years to build a combustion turbine to replace it. Also, if Transmission System reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to become operational. The time from final regulation to compliance may be difficult for some situations throughout the system.

Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed compliance equipment. Given the tight window for compliance, much of the capacity on the MISO system will need to take their maintenance outages concurrently. The need to take multiple units out of service on extended outage has significant potential to impact resource adequacy.

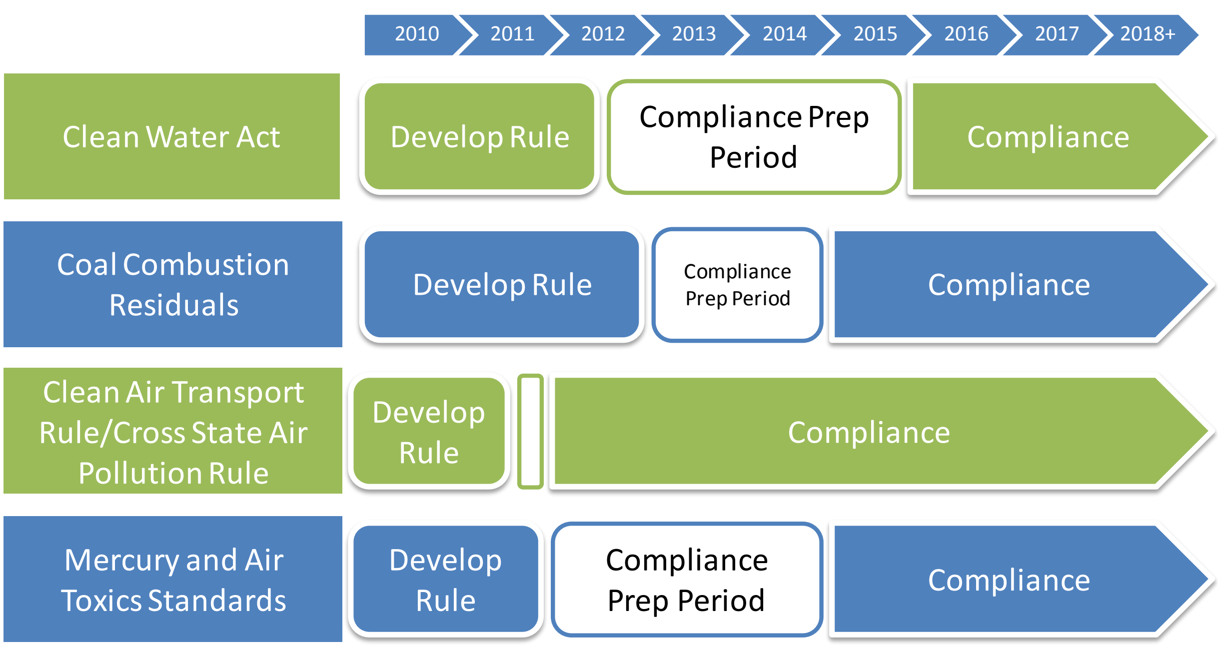



**Figure 2.1-2: Estimated timeline for regulation development and implementation**

## 2.2 Sensitivities impact

Just as in the MISO Transmission Expansion Plan (MTEP), MISO uses a scenario planning process in the analysis and evaluation of these EPA regulations. Evaluating the impact requires that many conditions be considered separately and in combination. MISO evaluated six scenarios with 77 sensitivities for each of the scenarios:

- Base conditions, no new regulations.
- Cooling Water Intake Structures section – 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT).
- Combination of all four regulations.

Figure  demonstrates the sensitivities evaluated for each analysis. Since there are six regulation scenarios there would be six branches to this decision tree, yet only the first branch is shown in Figure 2.2-1.

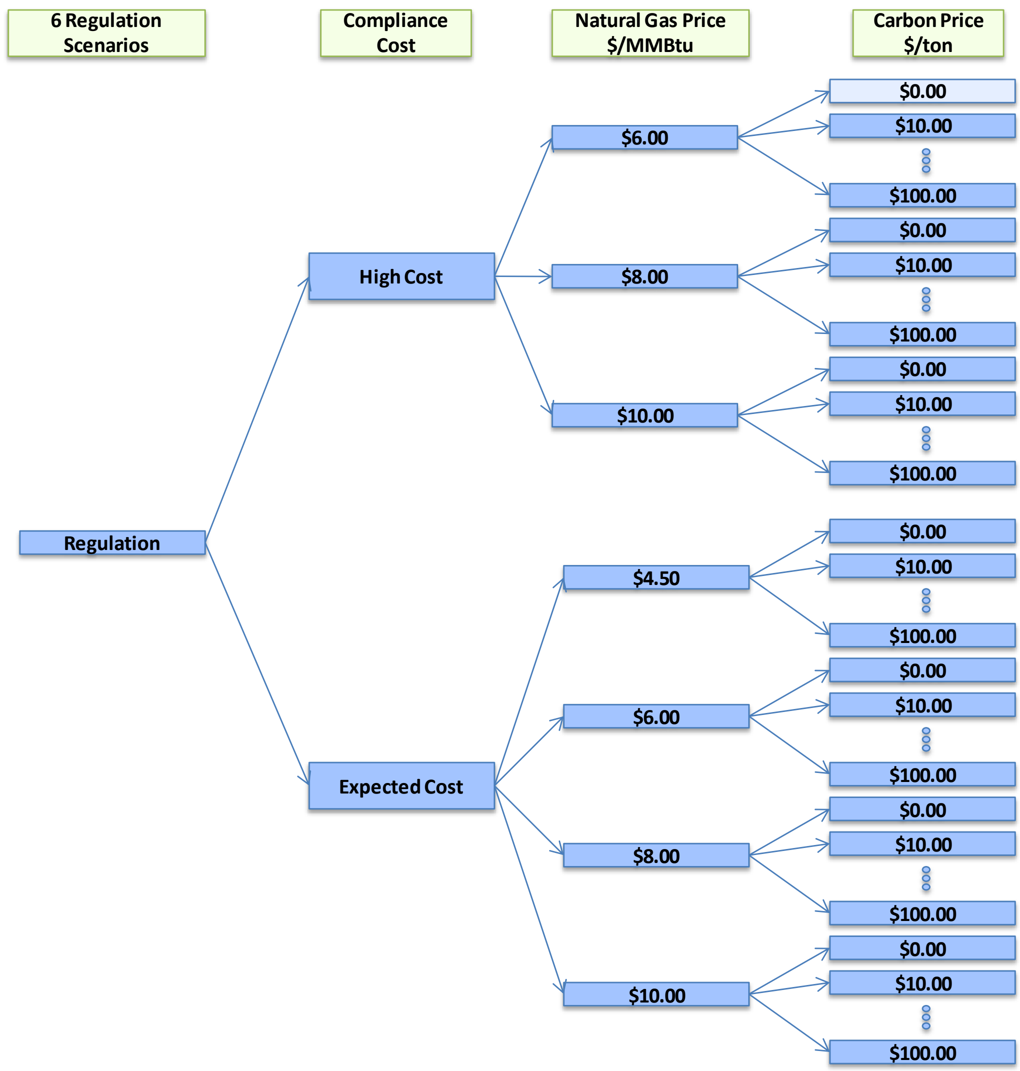



**Figure 2.2-1: Decision tree of EPA cases**

For each of the scenarios, 77 sensitivity cases consisting of two variations in compliance costs, natural gas costs and uncertainty risk costs represented as a cost to carbon production were modeled to produce a combined total of more than 400 sensitivity cases. The results indicated that up to 23,000 MW of coal capacity could be at-risk because of regulation compliance.

From these sensitivity cases, a few general conclusions can be made.

- **EPA regulation impacts:** Compliance associated with the Mercury and Air Toxics Standards (MATS) produces the most at-risk units, since its compliance costs and emission reductions have the greatest impact of the proposed regulations.

- **Stringent rule application:** Higher compliance costs to meet more stringent rules result in more at risk units. Evaluating all natural gas and carbon sensitivities for the stringent rule application cases resulted in up to 23,000 MW of at-risk capacity. However, running the same sensitivities at the more expected compliance costs as recommended and reviewed through the MISO stakeholder process, up to 13,000 MW of capacity was considered to be at risk.
- **Natural gas costs:** Lower natural gas prices produced more at-risk capacity than higher gas prices. The lower natural gas prices provide more incentive to retire capacity as the alternative resources provide competitive energy costs for the system. Conversely, when gas prices are high, the coal units find enough revenue on the system to cover compliance costs and keep general energy prices lower.

- **Risk costs:** MISO evaluated the risks associated with uncertainty in regulation compliance through costs added to megawatt-hour production. This cost was represented by adding a price to carbon. Because of this, higher compliance costs put more economic pressure on the coal units within the system, and the economics favor natural gas and carbon neutral capacity. So more coal units are at-risk for retirement with the higher compliance costs applied.

The units at-risk for retirement range from 0 MW to 23,000 MW based on the economic assumptions within the sensitivities. Cases where no units were identified to be at-risk for retirement include low compliance costs, higher gas prices and no risk costs applied. This occurs because it minimizes cost for compliance while increasing potential revenue within the energy market through higher natural gas prices. Cases that produce at-risk generation of up to 23,000 MW include stringent rule application, low gas prices and varying levels of risk costs.

Figure 2.2-2 depicts an example of the impacts of the cost of compliance, gas, and risk from the identified potential retirements of 2,919 MW with all four EPA regulations.

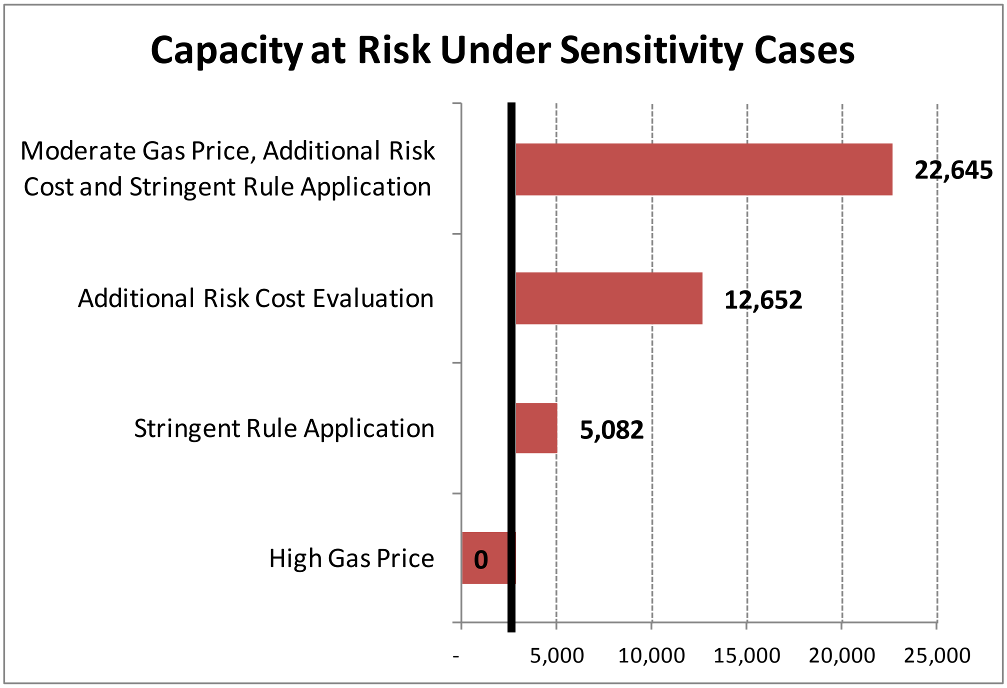



**Figure 2.2-2: Tornado chart demonstrating the impacts of sensitivities on potential capacity retirements**

## 2.3 Rate impact

In general, the retail rates on the system are driven by the costs of generation production, generation capital, transmission capital and distribution capital. The MISO EPA regulation analysis identifies costs that impact three of the four components of the rates.

The greatest impact on the rates comes from the capital cost component. The capital cost increase comes in two forms, the EPA capital compliance cost and the capital cost for replacement capacity. Figure 2.4-1 demonstrates the comparison of the rate impact of the two retirement scenarios with the current average system rate. The overall increase in the rates because of compliance with the EPA regulations is approximately 7.0 to 7.6 percent.

The relatively small rate increase difference between the two scenarios is due to the balance of capital cost configurations. The total EPA regulation related capital cost comes in three forms - 1) control equipment, 2) capital cost for replacement capacity and 3) transmission capital cost needed for retired capacity. The relationship between the three costs is a balance between retired capacity to forgo costs for control equipment while adding replacement capacity and transmission costs for the forgone capacity, versus more control costs to retrofit generation. In other words, as retirements increase, the total control equipment cost decrease, while replacement capacity and transmission costs increase – and vice versa. A balance of all three costs occurs to end up with the least cost strategy.

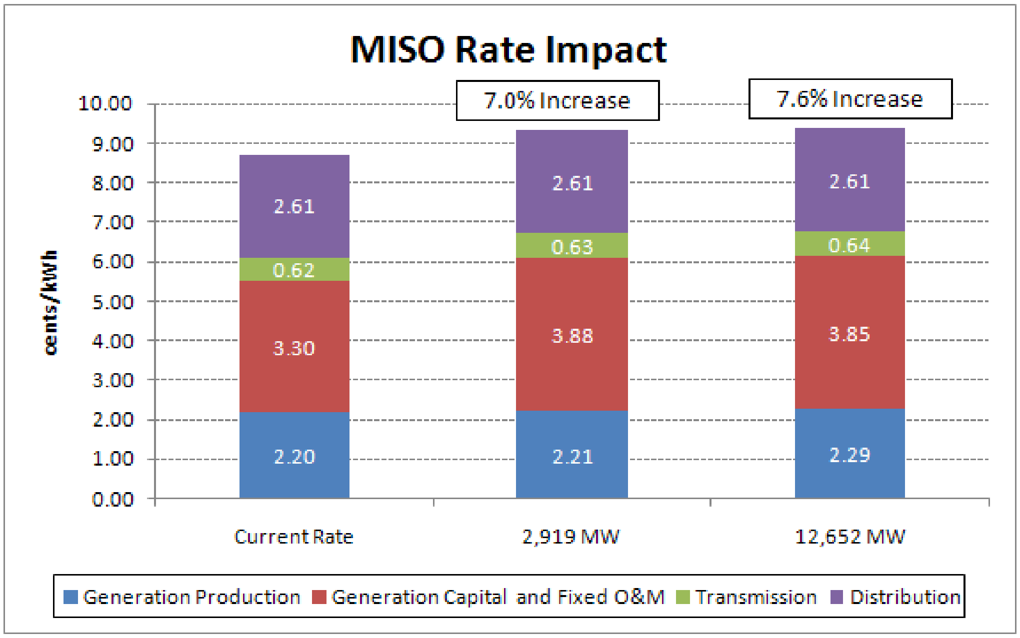



**Figure 2.4-1: MISO rate impact excluding the cost of carbon in the production costs**

# 3. MISO

MISO is an essential link in the safe, cost-effective delivery of electric power across all or parts of 12 U.S. states and the Canadian province of Manitoba. As a Regional Transmission Organization, MISO assures consumers of unbiased regional grid management and open access to the transmission facilities under MISO's functional supervision. Our cornerstones anchor our mission to pursue operational excellence and to drive value creation through transparent reliability/market operations, planning and innovation.

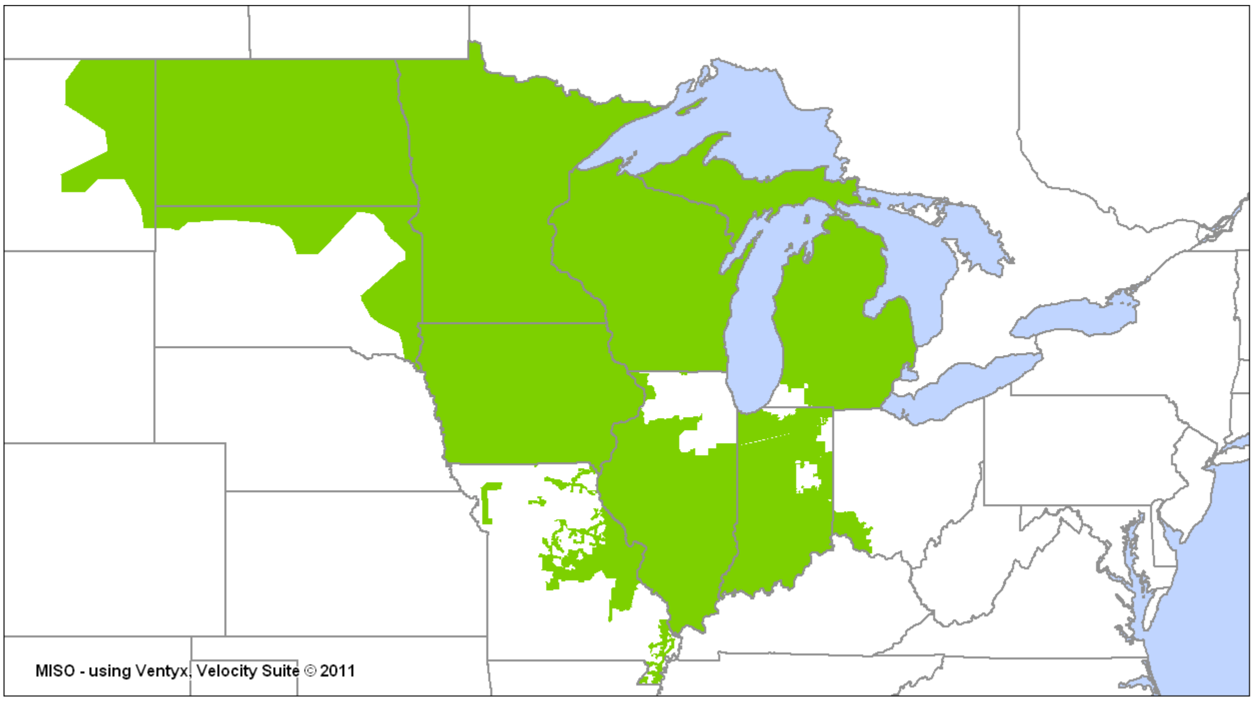



**Figure 3-1: MISO market footprint**

Membership gives Stakeholders a voice in the committee process, inviting them to provide advice and input on strategic and operational business decisions. It also guarantees participation in the election of MISO's Board of Directors. Each member gets a single vote and can represent one company or several. A list of MISO members can be found on the MISO website under the stakeholder center section.

## 3.1 Generating assets

MISO contains 134,900 MW of generating capacity in its market footprint, for which about 53 percent consists of coal-fired generation. Average age of the coal fleet is 45 years old. Coal units range from 2 - 1,300 MW in size.

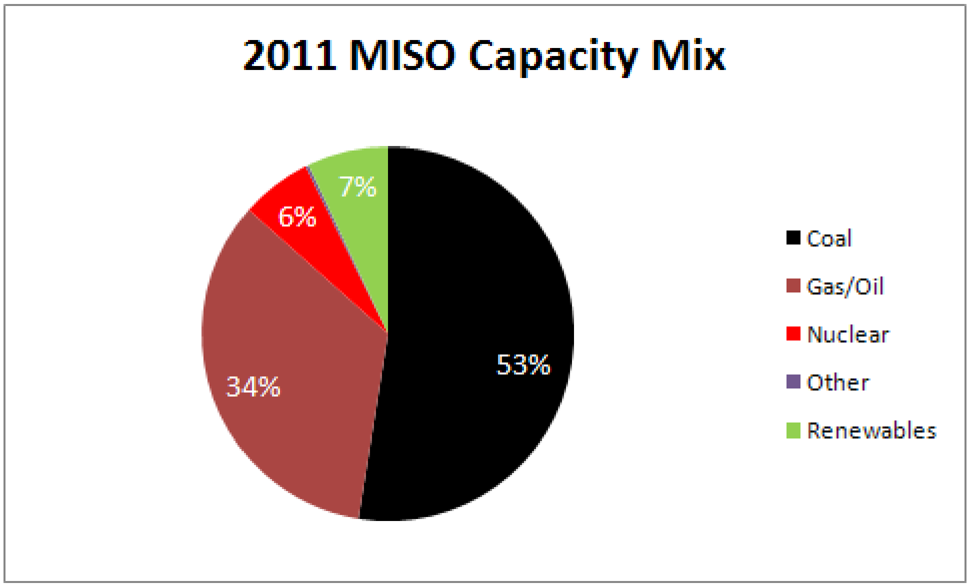



**Figure 3.1-1: MISO capacity mix**

Of the 70,000 MW of coal-fired capacity in the MISO market, less than half does not have plans for $SO_2$ controls. Furthermore, 38 percent have no $SO_2$ controls or $NO_X$ controls, and 38 percent have no $SO_2$ controls or Fabric Filters.

| | Capacity in MISO (MW) |
|---|---|
| Total Coal | 70,568 |
| No $SO_2$ Controls | 31,162 |
| No SCR or SnCR | 41,922 |
| No $SO_2$ and No SCR or SnCR | 26,643 |
| No $SO_2$ and No Fabric Filter | 26,714 |

**Table 3.1-1: Coal units existing or planned emission controls**

# 4. EPA regulations

The EPA finalized the Clean Air Transport Rule and is in the process of finalizing the three remaining proposed regulations that affect the electric industry:

- Cooling Water Intake Structures – section 316(b) of the Clean Water Act (CWA), the final rule is expected at the end of 2012.
- Coal Combustion Residuals (CCR), the final rule is expected at the end of 2011.
- Clean Air Transport Rule (CATR) as proposed in 2010. This regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July, 2011 after the study work was finalized.
- Mercury and Air Toxics Standards (MATS) formerly known as Electric Generating Unit (EGU). Maximum Achievable Control Technology (MACT), the final rule is expected at the end of 2011.

Each regulation is unique and has specific goals. As such, MISO evaluated the impacts on its system for each regulation separately and on all four combined. The study determined the impact and cost on the MISO system for capacity, Resource Adequacy, energy and transmission reliability.

## 4.1 Clean Water Act, Section 316(b)

Section 316(b) of the Clean Water Act (CWA) establishes the Best Technology Available (BTA) for Cooling Water Intake Structures to "minimize impingement and entrainment of aquatic organisms," in other words, preventing their encroachment. It a possible that BTA could be defined as re-circulating cooling system retrofits for all units employing once-through cooling systems. This is likely a worst case scenario. In the MISO analysis BTA is defined as retrofits to re-circulating cooling systems only if the retrofit is drawing its cooling source from an ocean, tidal river or estuary.

## 4.2 Coal Combustion Residuals

The purpose of the CCR is to regulate the coal fly ash under one of two methodologies. The first is to treat the ash as a special waste under subtitle C (hazardous waste) of the Resource Conservation and Recovery Act (RCRA). Under this option, facilities would need to close their surface ash impoundments within five years and dispose of the ash (past and future) in a regulated landfill with groundwater monitoring.

The second methodology is to regulate ash disposal as a non-hazardous waste under subtitle D of RCRA. This alternative would require the facility to remove the solids and retrofit the impoundment pond with a liner, protecting against groundwater contamination. Landfill coal combustion residuals disposal would require liners for new landfill and groundwater monitoring of existing landfills.

The second methodology is evaluated in this study.

## 4.3 Clean Air Transport Rule/Cross State Air Pollution Rule

The transport proposal reduces emissions that contribute to fine particle (PM2.5) and ozone non attainment that often travel across state lines. Sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) contribute to PM2.5 and ozone transport. A number of states plus the District of Columbia are affected by transport rule and illustrated in Figure . The rule allows units in each state to meet the emissions targets in any way the state sees fit, including unlimited trading of emissions allowances through an interstate trading program.

To assure emissions are reduced quickly, the EPA is proposing federal implementation plans, or FIPs, for each of the states covered by this rule. A state, however, may choose to develop its own plan to achieve the requirements, and may choose which types of sources to control.

Emission budget schedule implementation:

- Annual $SO_2$
  - Phase 1 group - 2012 cap that lowers in 2014
  - Phase 2 group - 2012 cap
  - Set emissions budget for each state
- Annual $NO_X$
  - 2012 state specific cap
- Ozone Season $NO_X$
  - 2012 state specific cap

The final CSAPR regulation came out after the analytics of this study were completed. The analysis and results presented in the study are from previous proposals of what was known as the Clean Air Transport Rule (CATR). Figures 4.3-1 and 4.3-2 show the applicable cap limitations to each state under the proposed CATR and final CSPAR regulation.

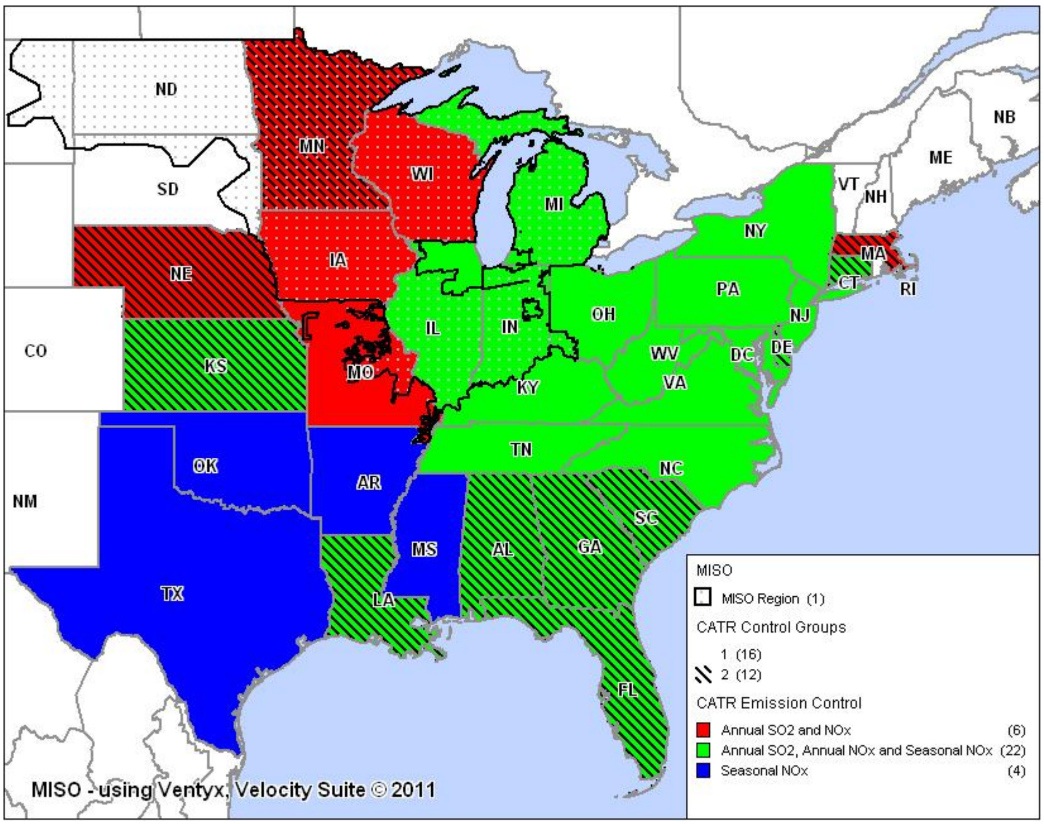



**Figure 4.3-1: Proposed Clean Air Transport Rule implementation**

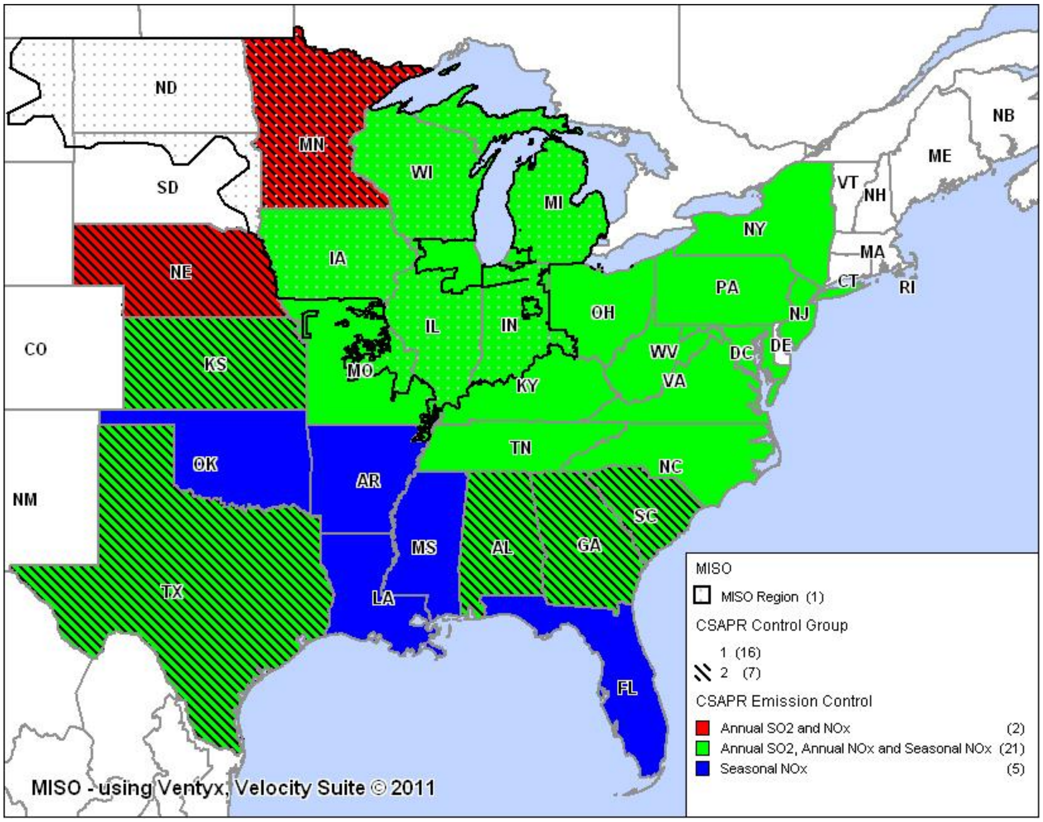



**Figure 4.3-2: Final Cross State Air Pollution Rule implementation**

## 4.4 Mercury and Air Toxics Standards

The primary focus of the Mercury and Air Toxics Standards is the reduction of emissions from heavy metals and acid gases. The heavy metals include mercury (Hg), arsenic, chromium and nickel; and, the acid gases include hydrogen chloride (HCl) and hydrogen fluoride (HF). A final rule will be expected towards the end of 2011. The following represent a few key highlights of the proposal:

- For all existing and new coal-fired Electric Generating Units (EGUs), the proposed MATS regulations would set numerical standards for mercury, Particulate Matter (PM), and HCl.
- For all existing and new oil-fired EGUs, the proposed toxics rule would establish numerical emission limits for total metals, HCl, and HF. Compliance with the metals standards is through fuel testing.
- For new units, proposed revisions to the New Source Performance Standards (NSPS) would include revised numerical EGU emission limits for PM, $SO_2$, and $NO_X$.

There are many technologies available to power plants to meet the emission limits, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems and baghouses.

## 4.5 Regulation timing

Figure demonstrates a high level timetable of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take a minimum of two to three years to build a combustion turbine to replace that capacity. Also, if Transmission System reliability requires bulk transmission upgrades, it could take at least five years for a transmission line to come into service. The time from regulation to compliance may be difficult for some situations throughout the system.

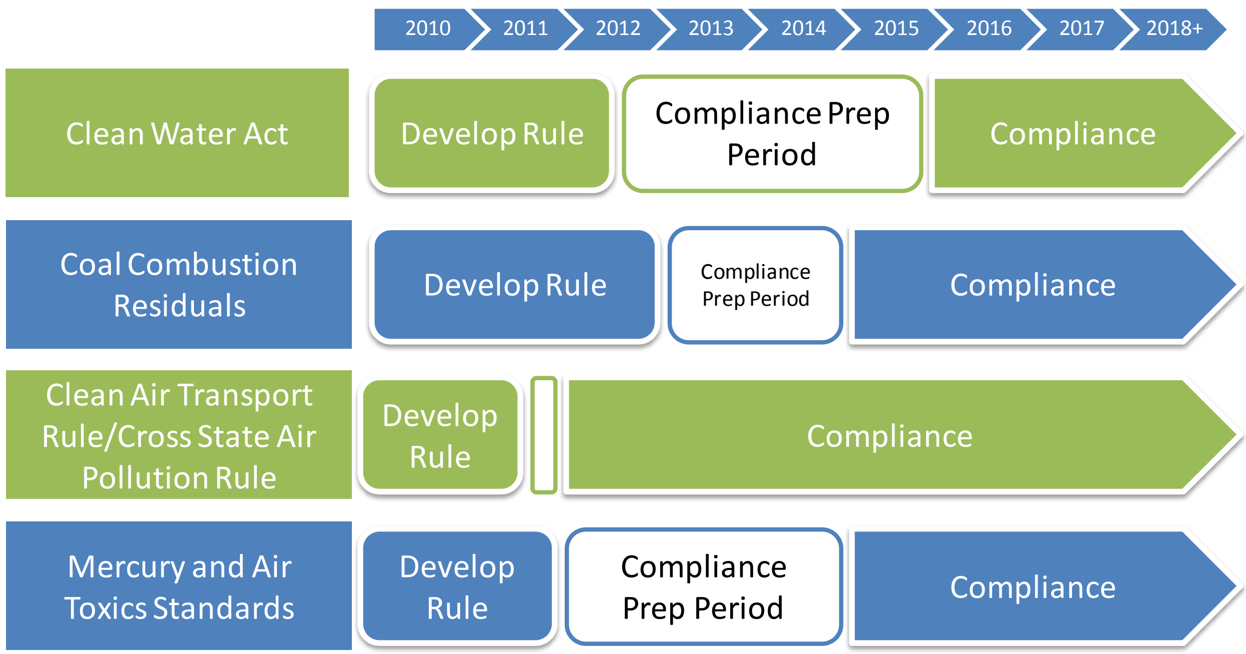



**Figure 4.5-1: Estimated timeline for regulation development and implementation**

## 4.6 Carbon restrictions

There are no regulations directing the amount of carbon produced from the existing fleet. However, recent endangerment findings that classify greenhouse gases as a hazardous air pollutant obligates the EPA to regulate its production. There have also been legislative proposals with certain targets for the reduction of carbon. One requires that the output of carbon should reduced by 40 percent from 2005 levels by 2030, and 83 percent by 2050. Although carbon is not currently regulated, prudence dictates that it be considered in the evaluation of the proposed EPA regulations.

# 5. Models

## 5.1 EGEAS

The Electric Generation Expansion Analysis System (EGEAS) software from the Electric Power Research Institute (EPRI) is used for long-term regional resource forecasting. EGEAS develops generation (and demand-side management) expansion plans based on long-term, least-cost optimizations with multiple input variables and alternatives. Optimizations can be performed on a variety of constraints, such as Resource Adequacy (loss-of-load hours), reserve margins or emissions constraints. The EPA study optimization is based on minimizing the 20-year capital and production costs, with a reserve margin requirement indicating when new capacity is required.

## 5.2 PROMOD IV®

PROMOD IV® is an integrated electric generation and transmission market simulation system that incorporates extensive details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions and market system operations. It performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV® forecasts hourly energy prices, unit generation, fuel consumption, bus-bar energy market prices, regional energy interchange, transmission flows and congestion prices. It uses an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, spinning reserve requirements and customer demand.

## 5.3 PSS®E

PSS®E is an integrated, interactive program simulating, analyzing and optimizing power system performance. PSS®E allows for detailed analysis of single hour operation based on defined system conditions such as system topology, demand and generation dispatch. This tool will allow the user to evaluate system reliability requirements with the transmission thermal limitations and required voltage levels at different points of the system.

## 5.4 GE-MARS

GE Energy’s Multi-Area Reliability Simulation (GE-MARS) is a transportation-style model based on a sequential Monte Carlo simulation that steps through time chronologically and produces a detailed representation of the hourly loads and hourly wind profiles in comparison with the available generation, in addition to interfaces between the interconnected areas.

GE-MARS calculates, by area or area group, the standard reliability indices of daily or hourly loss of load expectation (LOLE, in days per year or hours per year) and expected unserved energy (EUE, in megawatt-hours per year).

The basic calculations are done at the area level, which is how much of the data are specified and aggregated. Loads, wind profiles and generation are assigned to areas, and transfer limits are specified between areas.

# 6. Scope

The objective of the EPA Impact Analysis is to identify potential aggregate impacts of the EPA proposed regulations on the fleet within the MISO footprint. Specific key questions that are answered by the study are:

- Are there Resource Adequacy risks?
- Are there transmission adequacy risks?
- What are the impacts on the energy markets?
- What are the impacts on capital costs to the system?

Evaluation of study questions and results will be expressed at the MISO level only. It is understood that retrofit/retirement decisions are the responsibility of the asset owners. MISO will not share unit specific information with any entity outside of the asset owner at their request.

Figure 6-1 shows the three-phase study scope. The first phase screened the approximate 2,000 units in the MISO system to determine which of those units would be most at risk for retirement. The second phase used those results to determine the energy and congestion impacts on the system. The third phase developed the compliance and capital cost requirements, and evaluated the impact of Resource Adequacy, system reliability and customer rates.

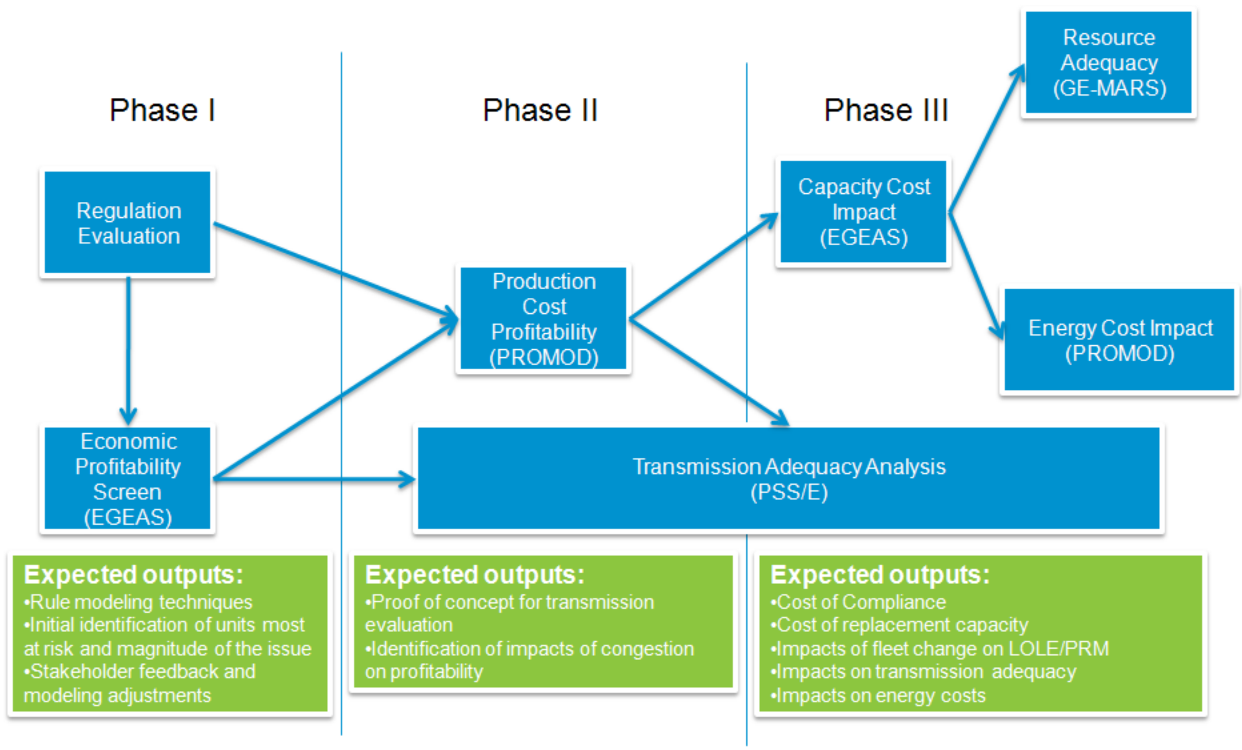



**Figure 6-1: Flow diagram of EPA Impact Analysis**

# 7. Phase I

Phase I consisted of three tasks: modeling techniques, profitability screening and MISO stakeholder interaction. MISO researched the proposed regulations and recent evaluations of the regulations. The research focused on the development of the modeling techniques used within the various models. This included looking at compliance technologies and their impacts on the operation and costs of units that may need to be retrofitted. MISO also surveyed asset owners on the control equipment already on the units.

The profitability screening utilized the EGEAS model. Existing system characteristics, compliance assumptions, sensitivities on gas prices and costs for carbon regulation were applied. This meant more than 400 screening cases had to be run to identify units on the system at-risk for retirement.

Stakeholders were given the opportunity to comment on inputs and outputs from the screening runs through the MISO Planning Advisory Committee. Their suggestions on compliance technologies and costs enhanced the analysis.

## 7.1 Phase I assumptions

The MTEP11 Business as Usual with Low Demand and Energy Growth Rate future was used as the base model in the regulation impact analysis. The demand growth rate was 0.78 percent and the energy growth rate was 0.79 percent. Both values are the effective growth rates determined through the MTEP process that include the impacts of projected demand response and energy efficiency resources. Detailed assumptions of the MTEP11 futures can be found in Appendix E2 of the MTEP11 report.

The EGEAS model is used in Phase I because of the ability to run 20-year study cases in a quick and efficient manner. For the EPA Impact Analysis study MISO ran more than 400 EGEAS cases, representing sensitivities on combinations of the proposed regulations:

- Base conditions, no new regulations.
- Cooling Water Intake Structures – section 316(b) of the Clean Water Act (CWA).
- Coal Combustion Residuals (CCR).
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR).
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT).
- Combination of all 4 regulations.

Figure  demonstrates the sensitivities evaluated for each regulation analysis. There are six regulation scenarios, so there would be six branches to this decision tree. Only the first branch is shown in this graphic.

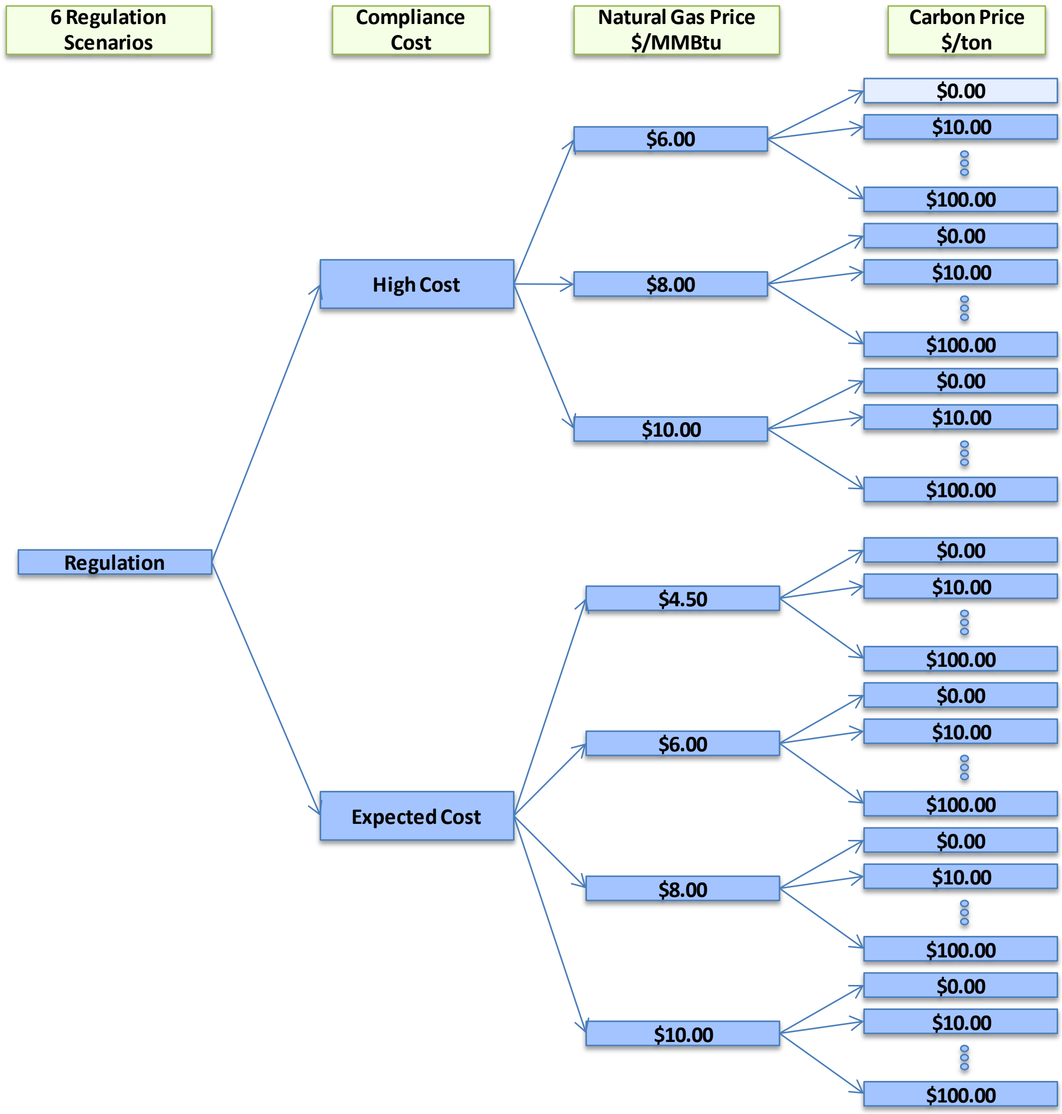



**Figure 7.1-1: Decision tree of EPA Cases (total of 77 sensitivities per regulation evaluated)**

## MATS, CWIS and CCR assumptions

To increase the efficiency of the EGEAS analysis, a rule set was developed for which control technologies to model based on unit characteristics. This allows MISO to model the entire system and provide a reasonable set of alternatives for the retrofit versus retire comparisons. Table 7.1- demonstrates the rule set that was created.

The Great Lakes were considered as “oceans” for this analysis. This provided some impact of the intake structure regulation on the land locked footprint of MISO. A tidal river is defined as a river which its flow is influenced by the tides. An estuary is a partly enclosed coastal body of water with one or more rivers or streams flowing into it, and with a free connection to the open sea.

| EPA Rule | Unit Type | Dry Scrubber | Dry Sorbent Injection | Activated Carbon Injection | Fabric Filter/Bag House | Recirculating Cooling | Fine Mesh Screens | Ash Conversion |
|---|---|---|---|---|---|---|---|---|
| MATS | Coal Units <=200MW | | Yes | Yes | Yes | | | |
| | Coal Units >200 MW | Yes if no Wet Scrubber | | | Yes | | | |
| CWIS | Oceans, Estuaries or Tidal rivers | | | | | Yes | | |
| | **Not** on Oceans, Estuaries or Tidal rivers | | | | | | Yes | |
| CCR | Coal Units | | | | | | | Yes |

**Table 7.1-1: Retrofit rule set for EPA regulations**

Generating unit operating affects from installation of various control technologies was also introduced into the EGEAS model. Stakeholders and public sources provided data. Ultimately the values used in this EPA Impact Analysis were provided and agreed to by the stakeholders. Table 7.1-2 shows the generating unit operating impacts after the installation of various control technologies.

| Control Technology | Capital Cost ($/kw) | Fixed O&M ($/kw-year) | Variable O&M ($/MWh) | Heat Rate (percent) | Max Capacity (percent) | Removal Rate (percent) |
|---|---|---|---|---|---|---|
| **Wet Scrubber** | 525 @ 500 MW | +10 | +1 | +1.5 | -1 | 95 percent $SO_2$ with .08 lbs/MMBtu floor |
| **Dry Scrubber** | 450 @ 500 MW | +8 | +1.5 | +1.5 | -0.7 | 90 percent $SO_2$ with .08 lbs/MMBtu floor |
| **Dry Sorbent Injection** | 40.6 @ 200 MW | +3.40 | +9.7 Bituminous Coal +4.4 Lignite and Sub-Bituminous Coal | +.02 | -.02 | 70 percent $SO_2$ with .08 lbs/MMBtu floor |
| **Activated Carbon Injection with Fabric Filter** | 275 @ 500 MW | +4 | +1 | N/A | N/A | 90 percent Mercury |
| **Fabric Filter/Bag House** | 150 @ 500 MW | N/A | N/A | N/A | N/A | 90 percent PM |
| **Recirculating cooling conversion** | 150 @ 500 MW | +1.5 | N/A | +1.5 | -1 | N/A |
| **Fine Mesh Screens** | 90 @ 500 MW | N/A | N/A | N/A | N/A | N/A |
| **Wet to Dry Ash conversion** | $30 Million + $80 w/ FGD or $200 w/o FGD | N/A | +1 | N/A | N/A | N/A |

**Table 7.1-2: Unit impacts due to control technologies**

## CATR assumptions

The proposed Clean Air Transport Rule (CATR) was the guiding regulation used within this analysis. The finalized Cross State Air Pollution Rule (CSAPR) limits are more stringent than those in this study. There is a possibility that with the newer limits the impact is greater than seen in this report. The CATR regulation sets statewide emission limits for $SO_2$, $NO_X$, and $NO_X$ Ozone. MISO is able to model state limitations within the EGEAS model. EGEAS will take those limits and dispatch the units in each state to meet the state limits. This closely models the unlimited intrastate trading with no interstate trading.

For this study EGEAS is run at an RTO/ISO level and as such some states might span across multiple RTO/ISO's. Just applying the state limit would cause the limit to be too high in some cases. An example would be a state that has ten units but only one is in MISO. That would mean one unit would have a limit set intended for ten units. To accommodate multi-regional states, the emission limits were prorated by the capacity of the units in each RTO/ISO.

Table 7.1-3 demonstrates the state and region emission budgets under the draft CATR. These were the numbers applied to the impact analysis. The CSAPR was finalized in July, 2011 and as such those numbers in are represented in Table 7.1-4 for comparison purposes only. Initial analysis suggests that the emission budgets are reduced for some states and re-categorized for other states.

| State | GROUP | 2012-2013 $SO_2$ Annual Limit (Tons) | 2014+ $SO_2$ Annual Limit (Tons) | 2014+ $NO_X$ Annual Limit (Tons) | 2014+ $NO_X$ Ozone Annual Limit (Tons) |
|---|---|---|---|---|---|
| Illinois | I | 208,957 | 151,530 | 56,040 | 23,570 |
| Indiana | I | 400,378 | 201,412 | 115,687 | 49,987 |
| Iowa | I | 94,052 | 86,088 | 46,068 | - |
| Kentucky | I | 219,549 | 113,844 | 74,116 | 30,908 |
| Michigan | I | 251,337 | 155,675 | 64,932 | 28,253 |
| Minnesota | II | 47,101 | 47,101 | 41,322 | - |
| Missouri | I | 203,689 | 158,764 | 57,681 | - |
| Ohio | I | 464,964 | 178,307 | 97,313 | 40,661 |
| Wisconsin | I | 96,439 | 66,683 | 44,846 | - |
| Other States | I/II | 1,907,404 | 1,340,599 | 778,307 | 468,235 |
| Total | I/II | 3,893,870 | 2,500,003 | 1,376,312 | 641,614 |

**Table 7.1-3: State emission budget for draft CATR as used within the analysis**

| State | GROUP | 2012-2013 $SO_2$ Annual Limit (Tons) | 2014+ $SO_2$ Annual Limit (Tons) | 2014+ $NO_X$ Annual Limit (Tons) | 2014+ $NO_X$ Ozone Annual Limit (Tons) |
|---|---|---|---|---|---|
| Illinois | I | 234,889 | 124,123 | 47,872 | 21,208 |
| Indiana | I | 285,424 | 161,111 | 108,424 | 46,175 |
| Iowa | I | 107,085 | 75,184 | 37,498 | 15,886 |
| Kentucky | I | 232,662 | 106,284 | 77,238 | 32,674 |
| Michigan | I | 229,303 | 143,995 | 57,812 | 24,233 |
| Minnesota | II | 41,981 | 41,981 | 29,572 | - |
| Missouri | I | 207,466 | 165,941 | 48,717 | 20,440 |
| Ohio | I | 310,230 | 137,077 | 87,493 | 37,792 |
| Wisconsin | I | 79,480 | 40,126 | 30,398 | 12,420 |
| Other States | I/II | 1,657,409 | 1,139,204 | 639,886 | 360,377 |
| Total | I/II | 3,385,929 | 2,135,026 | 1,164,910 | 571,205 |

**Table 7.1-4: State emission budget for final CSAPR**

## 7.2 Phase I results

To identify at-risk capacity on the system, MISO had to develop a methodology to evaluate the profitability of the units. This was achieved through the calculation of annual revenues and costs for each generating unit and determining net margins for the units. The units with a net margin of less than $0/kW were deemed to be either Tier I at-risk units or Tier II potentially at-risk units.

The net margin for each generating unit is calculated by subtracting annual costs from annual revenues. The next step is to list all the generating units in order of decreasing net margin for each year of the study period. From this ordered list of generating units, the marginal unit can be determined. The marginal unit is the unit at which the cumulative capacity equals the capacity requirements to meet the planning reserve margin (PRM) criterion. The offset adder expressed in $/kW is the required amount of net margin adder that will make the marginal unit whole. For example, as shown in **Table** 7.2-1, the net margin of the marginal unit, $U_n$, is -$450/kW, and the offset adder would be $450/kW to make the marginal unit whole. This offset adder is then applied to all units in the ordered list.

| Unit | Net Margin | Capacity | Cumulative Capacity | Reserve Margin |
|---|---|---|---|---|
| $U_1$ | $200/kW | 400 MW | 400 MW | |
| $U_2$ | $175/kW | 650 MW | 1050 MW | |
| $U_3$ | $130/kW | 160 MW | 1210 MW | |
| … | … | … | … | |
| … | … | … | … | |
| $U_{898}$ | $0/kW | 330 MW | 100,000 MW | |
| $U_{1000}$ | -$45/kW | 80 MW | 110,000 MW | |
| $U_n$ | -$450/kW | 125 MW | 118,000 MW | 17.40 percent |
| $U_{n+1}$ | -$550/kW | 30 MW | 118,030 MW | 17.4 percent + |

**Table 7.2-1 Pictorial representation of Tier I and Tier II units**

Two different sets of offset adders were calculated and used to determine which generating units are to be classified as Tier I and Tier II units. The Tier I offset adders are based on the EGEAS cases for each specific EPA regulation, whereas the Tier II offset adders are based on the results of the EGEAS Base Case assuming no EPA Regulations. By definition, the Tier I offset adders are greater than the Tier II offset adders, since the Tier II offset adders do not include the added costs for the various EPA control systems needed to meet compliance. Table 7.2-2 provides an example of the Tiers. Units at risk are those at the bottom of the dispatch order, where the revenue intake may or may not cover the costs of compliance. Since MISO does not capture all revenue for a unit, this methodology provides reasonable cut-offs based on the PRM system reliability objective.

| Unit | Net Margin from Regulation Case | Net Margin with EPA Regulation Offset Adder ($200/kW) | Net Margin with Base Conditions Offset Adder ($100/kW) | At-Risk Status |
|---|---|---|---|---|
| U1 | $200/kW | $400/kW | $300/kW | Not at-risk |
| U2 | $100/kW | $300/kW | $200/kW | Not at-risk |
| U3 | $50/kW | $250/kW | $150/kW | Not at-risk |
| U4 | $0/kW | $200/kW | $100/kW | Not at-risk |
| U5 | -$50/kW | $150/kW | $50/kW | Not at-risk |
| U6 | -$100/kW | $100/kW | $0/kW | Not at-risk |
| U7 | -$150/kW | $50/kW | -$50/kW | Tier II |
| U8 | -$200/kW | $0/kW | -$100/kW | Tier II |
| U9 | -$250/kW | -$50/kW | -$150/kW | Tier I |
| U10 | -$300/kW | -$100/kW | -$200/kW | Tier I |

**Table 7.2-2: Example of Tier I and Tier II identification**

If a unit is identified as a Tier I unit in any of the sensitivity cases, it is classified as Tier I for the entire set of runs. Therefore, not any one scenario will result in the total identified Tier I list, but a combination of the unique units from all of the sensitivity cases.

## Stringent rule applications

MISO ran more than four hundred sensitivities on the EPA regulations where Tier I and Tier II units were identified. Most of the sensitivities focused on combinations of gas and carbon prices. They were run on two variations of compliance with the EPA rules. Compliance with the rules was modeled at a high cost application and a more expected cost application. The differences in the two methods of modeling can be seen in Table 7.2-3.

| High Cost Application | Expected Cost Application |
| --- | --- |
| Compliance costs applied in 2011 with 10 year recovery period | Compliance costs applied in 2015 with 20 year recovery period |
| SCR required to meet MATS | SCR NOT required to meet MATS |
| Closed loop cooling applied to all steam units | closed loop cooling applied to oceans, tidal rivers and estuaries |
| FGD applied to all units <=200MW | DSI applied to all units <=200MW |
| Carbon prices applied in 2011 | Carbon prices applied in 2015 |
| No $4.5/MMBtu gas price in sensitivities | $4.5/MMBtu gas price in sensitivities |

**Table 7.2-3: Modeling differences between compliance modeling methodologies**

Modeling of the compliance high cost application resulted in the identification of 102 Tier I coal units amounting to 5,082 MW of capacity and an additional 116 Tier II coal units amounting to 22,645 MW of capacity. Figure  provides a histogram of the units identified by Tier. The most at-risk units identified in Tier I are less than 200 MW while the Tier II units can get up to larger sizes. The modeling runs identify that the most at-risk units come from the application of compliance costs combined with lower gas prices, where the higher values of those units in the Tier II list tend to show up as potentially at-risk because of the application of costs to carbon. It was also found through the sensitivity analysis that the MATS regulation is the primary driver in placing units at risk for retirement.

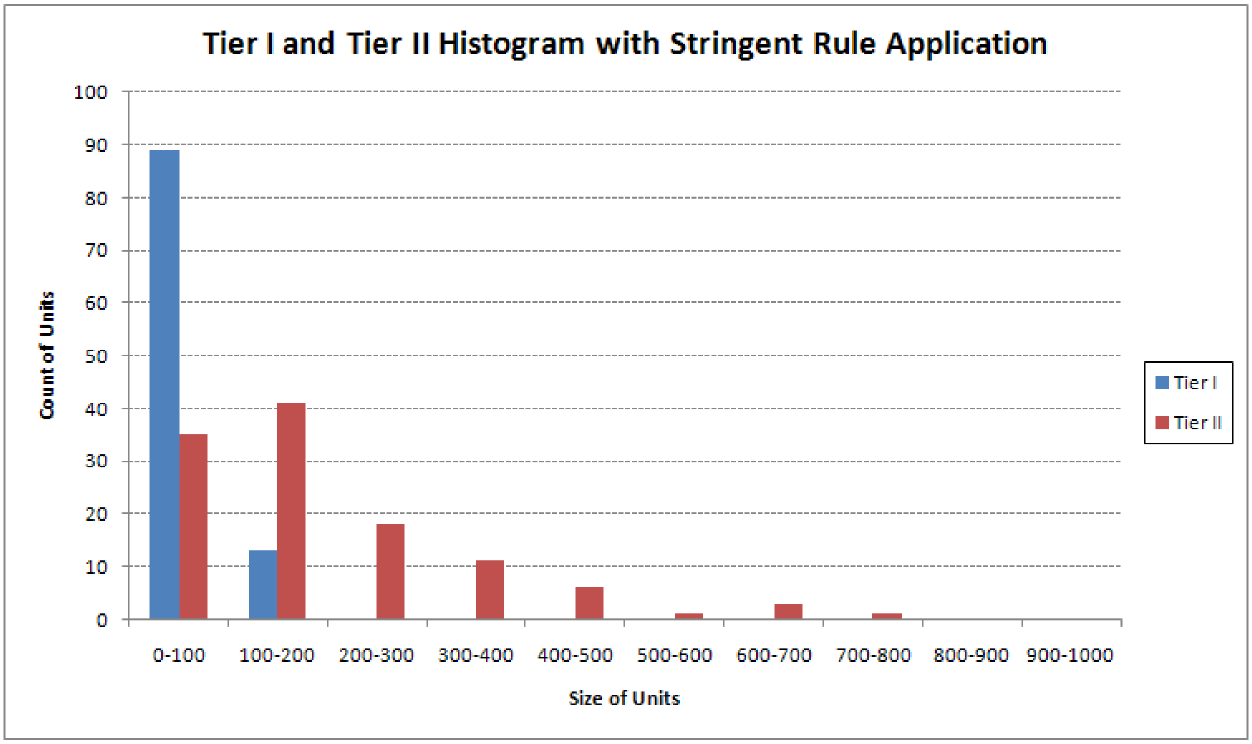



**Figure 7.2-1: Tier I and Tier II histogram stringent rule application**

## Expected compliance cost application

The modeling of the lower, more realistic compliance application reduced affected generation on the Tier I and Tier II lists. In this set of sensitivity cases, Tier I accounts for 53 coal units amounting to 2,764 MW of capacity and Tier II accounts for an additional 98 coal units amounting to 9,885 MW of capacity. The adjustment in capacity cost modeling identifies more of the smaller coal units on the system as Tier II rather than Tier I as seen in the compliance cost application cases, Figures 7.2-1 and 7.2-2. The expected compliance cost application also identifies no units greater than 300 MW in either of the Tiers. The average age of the units identified is 52 years.

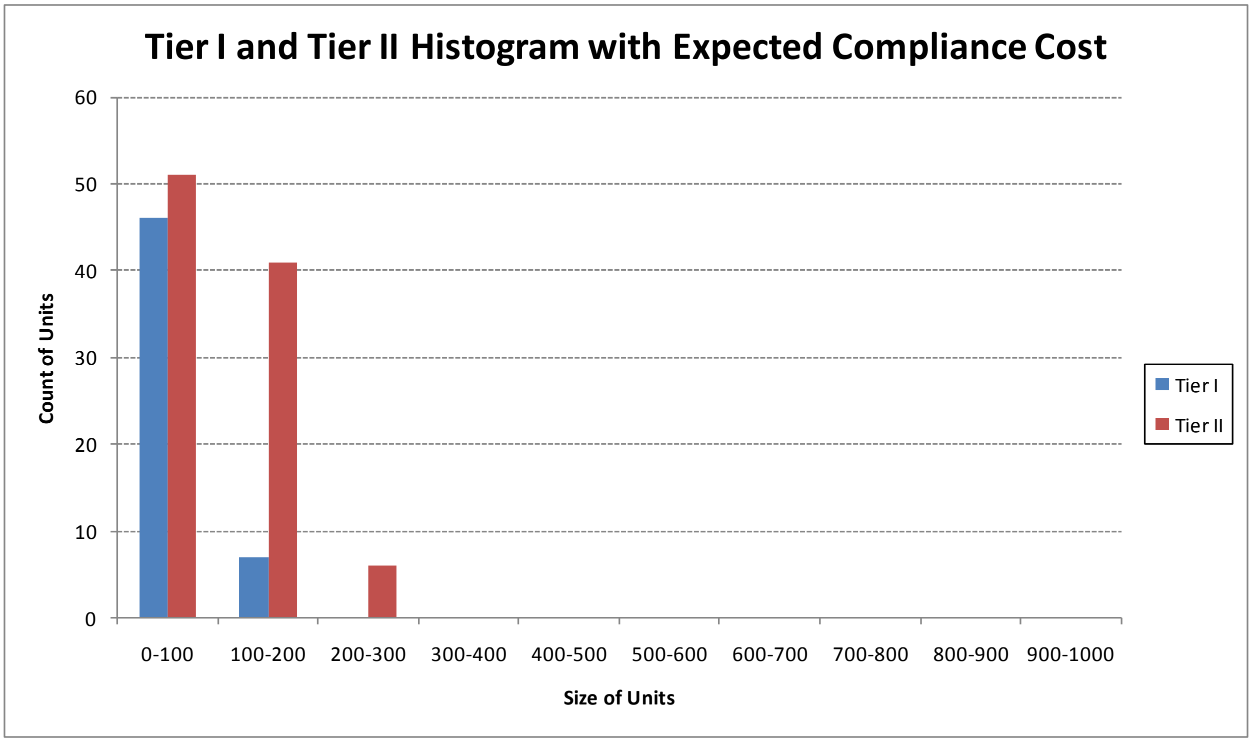



**Figure 7.2-2: Tier I and Tier II Histogram for expected compliance cost application**

## 7.3 General observations of sensitivity screens in Phase I

The sensitivity cases help identify which variables have the greatest impact on whether coal-fired generators may be at-risk:

- A greater cost for compliance will cause more coal units to be at risk.
- Lower gas prices cause a greater amount of at-risk coal capacity. This is due to lowered revenue on the system since the clearing energy price for peaking capacity is lower. Higher gas costs provide more revenue for coal units and lower the risk for retirement on the system.
- Carbon costs drive more coal units to be at risk. However, carbon costs combined with higher gas prices could mitigate the amount of at-risk capacity.

# 8. Phase II

EGEAS does not include the detailed Transmission System within the modeling capability. So it was determined that PROMOD IV® would be utilized to identify if congestion on the Transmission System could provide additional revenue to generators to remove them from the list of Tier I and Tier II units identified in Phase I.

## 8.1 Phase II assumptions

Four sets of sensitivities were modeled within the PROMOD IV® model, as shown in Table 8.1-1. These cases represent results from Phase I that maximized and minimized retirements under the MATS only cases and the cases representing a combination of all the studied regulations. The MTEP11 2016 summer peak model was used for the transmission model. The years evaluated included 2016, 2021 and 2026.

| Phase II PROMOD IV® Cases |
|---|
| MATS Regulation, Expected Compliance Costs, $4.50 Gas and $100 Carbon |
| MATS Regulation, Expected Compliance Costs, $10 Gas and $0 Carbon |
| Combined Regulations, Expected Compliance Costs, $4.50 Gas and $100 Carbon |
| Combined Regulations, Expected Compliance Costs, $10 Gas and $0 Carbon |

**Table 8.1-1: Phase II analysis assumptions**

Because MISO models the Eastern Interconnection within the PROMOD IV® models, high level EPA evaluation and EGEAS runs had to be made for the entire model footprint. This is done to maintain appropriate cost balances between MISO and the other regions.

Each PROMOD IV® case was run under copper sheet (no transmission limitations) and constrained conditions. The difference between the generation revenue and generation cost for those cases provides the transmission impact on the revenue and cost, or net margin, for each unit on the MISO system. Comparing these results from the Phase I results will show the transmission impact on the Tier I and II list.

## 8.2 Phase II results

Phase II results indicate that some of the units on the Tier I and II lists are in locations where greater revenues can be received due to congestion. Of the Tier I units identified in the expected compliance cost set of sensitivities, 12 units amounting to 594 MW result in a positive net margin with the addition of transmission congestion revenue. In Tier II, 28 units amounting to 2,957 MW become profitable.

The congestion revenue information is important because it shows that congestion on the system may provide additional revenue for some generating units. However, the following Phase III analysis does not include the additional congestion revenue. The revenue number identified is a one year representation from the production cost model runs where the capacity expansion looks at the interaction of retirement and retrofit decisions over a 20 year period. Additional analysis will be needed to include a transmission congestion component in the future.

## 8.3 General observations of PROMOD IV® Analysis

The Phase II provided analysis shows the following results.

- A total of 3,551 MW could possibly be in transmission sensitive areas.
- Transmission congestion could provide additional revenue that is not captured in the MISO EGEAS analysis of the retirements of at-risk capacity.

# 9. Phase III

Phase III of the analysis answers four questions posed at the beginning of the study.

- What are the impacts on capital costs to the system?
- Are there Resource Adequacy risks?
- What are the impacts on the energy markets?
- Are there transmission adequacy risks?

These questions are answered utilizing four different models. EGEAS was used to evaluate the capital investment costs. These costs include both compliance retrofit costs and replacement capacity costs for retired capacity. The GE-MARS model was used to evaluate the impacts of retirements and retrofits on the Loss of Load Expectation (LOLE) analysis. The PROMOD IV® was used to determine energy cost impacts. Finally, the PSS®E model was used to evaluate Transmission System adequacy for the retirement of units on the system.

## 9.1 Phase III assumptions

The EGEAS retirement versus retrofit analysis was performed on the case that included expected compliance cost application, a gas cost of $4.50/MMBtu and $0/ton carbon cost. Additionally, increasing levels of carbon costs were also modeled to capture the impacts of the uncertainty of future carbon regulation on the retirement decision.

To perform the EGEAS analysis, two model runs were made for each unit from the expected compliance cost application Tier I and II list. One modeled the unit and its retrofit controls and one modeled the retirement of the unit with replacement capacity. The output with the lowest cost determined the strategy of the unit tested.

The outputs of the EGEAS analysis are passed to the other models. The inputs to those models will include the retirement versus retrofit decision as well as compliance technology impacts and future replacement capacity.

## 9.2 Phase III results

MISO ran two economic alternatives. The first evaluated a $4.50 natural gas cost, compliance for all the identified regulations and an expected cost for compliance with the regulations based on MISO stakeholder feedback through the study process. The second analysis evaluated increased compliance costs on the system. These increased costs are represented through a production cost adder, and is proxy for costs associated with the uncertainty around rules not finalized, additional life extension costs needed for balance of plant as well as the considered risk around the uncertainty of the treatment of green-house gases. It is expected that one or all are within the assumption error bounds for this analysis and the impacts will be considered in the fleet strategies of the asset owners. The results of the EGEAS analysis produced:

- **2,919 MW** of coal fleet capacity at-risk for retirement under all likely scenarios. As of the publishing of this study, retirement requests of the coal fleet have amounted to 2,500 MW in the MISO Attachment Y process.
- **12,652 MW** of coal fleet capacity at-risk for retirement identified to be within prudence considerations and error bounds for the assumptions of the MISO study.

The EGEAS retirement analysis minimizes the total system net present value costs over a twenty year planning period plus a forty year extension period. When the 2,919 MW and 12,652 MW of retired capacity were forced into the model with no cost of carbon applied, it was shown that the overall net present value of system costs varied by approximately 1 percent. This value is within the tolerance of assumption error. Additionally, MISO did not consider unit life extension costs in its evaluation. Because of these two considerations, it is expected that the higher value of nearly 13,000 MW is more realistic of the potential retirements on the system.

## Capacity cost impact

Table 9.2-1 demonstrates the 20-year net present value of capital cost affects of the EPA regulations from the EGEAS modeling runs in 2011 dollars. The comparison of the costs are based on the retirement impacts of 2,919 MW from the non-carbon analysis and 12,652 MW from the carbon analysis compared to the non-carbon, no EPA regulation compliance base case. It's assumed that capacity retires in the year 2015. As can be seen, compliance capital costs are in the range of $22.5 billion to $28.2 billion. Capacity capital fixed charges increase by $1.7 billion to $9.6 billion and fixed operations and maintenance costs range from no increase to $1.1 billion. The total capital cost for compliance with the EPA regulations ranges from $31.0 billion to $32.1 billion.

| | No Regulation Case | 2,919 MW of Retirements | 12,652 MW of Retirements |
|---|---|---|---|
| EPA Compliance Retrofit Capital Costs | $0.0B | $28.2B | $22.5B |
| New Capacity Capital Fixed Charges | $68.8B | $70.5B | $78.4B |
| Fixed O&M Costs | $45.7B | $46.8B | $45.7B |

**Table 9.2-1: 20-year NPV capital cost impact of EPA regulations (2011 dollars)**

## Resource Adequacy impact

The impact of EPA regulations on the Resource Adequacy of the MISO system is dependent on how the system is maintained during the retirement or replacement of affected units. Assuming a controlled replacement of capacity as it is retired, system reliability is actually improved. As the older and less reliable units are removed, the system average forced outage rate decreases marginally. This decrease in outage rates (less than 1 percent in both cases) when applied to the entire system results in Planning Reserve Margin decreases of up to 1 percent from 17.4 percent with the current system to 16.4 percent in a system where 12,652 MW of capacity is replaced with system average units.

As an analysis of the base reliability of the MISO system, if all units within the footprint were assumed committed to Resource Adequacy, the Loss of Load Expectation (LOLE) would be roughly 0.088 days per / year. If the capacity flagged for retirement in this section was removed and not replaced, the loss of 2,919 MW would decrease the base reliability to the point where the LOLE would be 0.21 days per year, twice the current target of 0.1 days per year or one day in 10 years. If all 12,652 MW of capacity were removed from the system and not replaced the resulting LOLE would yield a system with 10 times the probability for outage as the current benchmark or 1.028 days per year.

Removal of capacity without replacement is an unlikely scenario and maintenance of the Planning Reserve Margin is obligated under the MISO tariff. In order to analyze the effects of a system where the reserve margin was maintained, all removed capacity was replaced by theoretical new units which had an outage rate equivalent to the system average after unit removal. In this case when 2,919 MW of capacity was retired and the reserve margin maintained the LOLE improved from the target of 0.1 to 0.093 days per year. When 12,652 MW was retired and replaced in the same fashion the reliability improved even more to 0.068 days per year.

This is indicative of the improved average forced outage rates experienced when less reliable units are removed and replaced with more reliable units. The starting system average forced outage rate was 8.0248 percent where the removal of 2,919 MW improved average forced outage rate to 7.9983 percent and 12,652 MW of retirements resulted in a 7.9864 percent.

As a final analysis of the impact of unit retirement and replacement with system average units, a hypothetical reserve margin was established. Since the system average forced outage rates declined after the retirements, it can be assumed that Planning Reserve Margins would drop. This was indeed the case as starting from the 17.4 percent reserve margin established in the base case, 2,919 MW of retirements lowered the reserve margin to 17.2 percent. Likewise the retirement of 12,652 MW resulted in a decrease in reserve margin to 16.4 percent. In either case it was assumed that retired units would be replaced by units that matched the system average forced outage rates. The reliability of the system is ultimately dependant on many factors including the availability of the units. If the units identified as at risk for retirement are all replaced with units that have better availability, system reliability will improve.

## Energy cost impact

The EPA regulations have two primary impacts on the cost of energy on the system. First, the production of energy by coal units that require retrofits for compliance will be negatively affected. The impacts on heat rates and variable operations and maintenance costs will make many units less efficient and more expensive. Also, units selected for retirement will remove the lower cost coal energy from the system. They will eventually be replaced by the higher cost natural gas energy replacement units. This will put a greater dependence on the natural gas units to meet the system energy requirements at higher production costs.

Both identified retirement scenarios were modeled within PROMOD. Figure shows that both scenarios increase the average cost of energy on the MISO system. The retirement of 2,919 MW of capacity will result in a slightly less than $1 per MWh average cost increase in 2011 dollars. The retirement of 12,652 MW of capacity on the system leads to an average cost of energy increase near $5/MWh in 2011 dollars.

When carbon costs are added to the cost of energy, the average LMPs on the system increase by approximately $30/MWh. In Figure , it can be seen that the 2,919 MW of retirement case results in greater energy costs than the 12,652 MW retirement case. This occurs because the higher retirement case was optimized with carbon costs considered and the higher retirements reduce carbon emissions by replacing coal capacity with natural gas capacity.

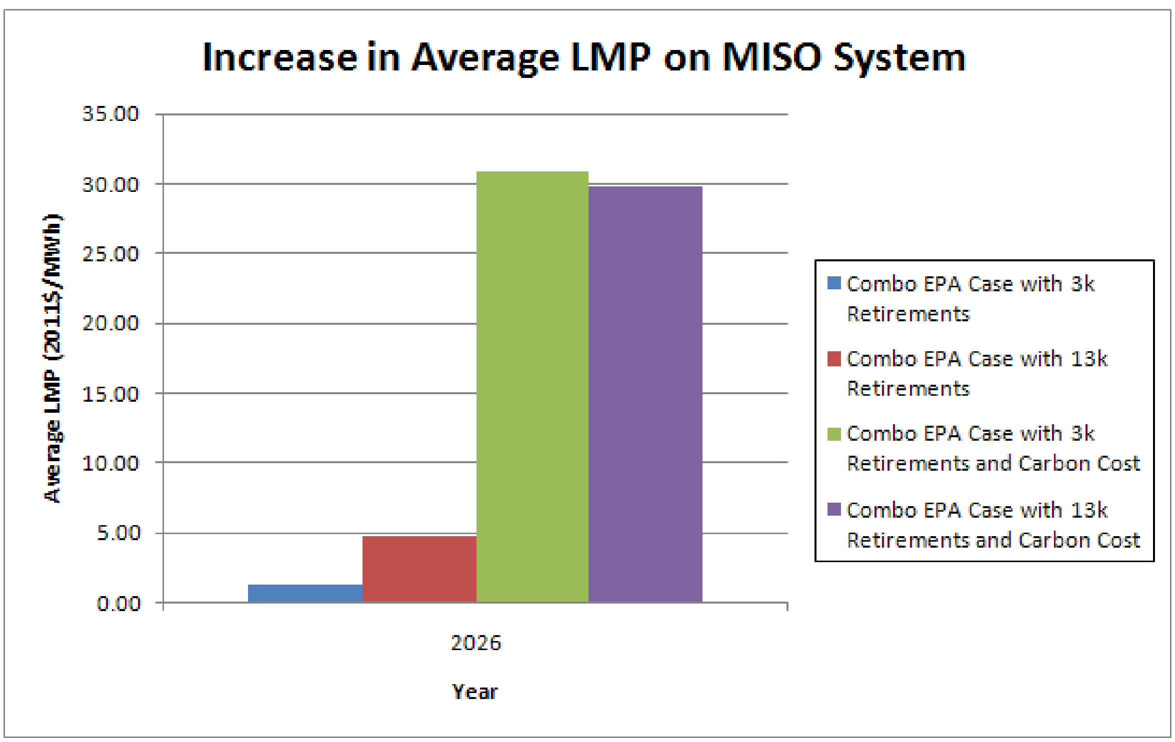


**Figure 9.2-2: MISO average LMP impact**

## Transmission reliability cost impact

Transmission investment that would be needed to meet applicable reliability criteria after the retirement of 2,919 MW and 12,652 MW were studied as separate scenarios, based on the expected summer peak system configuration in 2015. This analysis assumed that none of the retired units that caused transmission problems was replaced with new generation. Replacement generation dispatch was assumed to be sourced within the MISO footprint.

Analysis indicated that although the total cost of transmission upgrades needed to ensure reliable system operations is relatively small, some of these upgrades may not be able to be implemented by the time some of the units would need to be retired due to EPA regulations. In such events, the units would need to make arrangements to continue operation, or firm load service could be at risk during certain hours of the year until the transmission upgrades could be implemented.

The total expected transmission investment under the 2,919 MW retirement scenario involving 22 generating stations is $580 M, of which $500 M represents estimated upgrades required for retirements at one station.

The 12,652 MW scenario involved an additional 51 stations, and could require an estimated additional $300 M in transmission upgrades, for a total of about $880 M in transmission investment.

Overall 160 units at 73 stations are considered more likely candidates to be considering retirement. Transmission system upgrades are expected to be required to maintain system reliability after retirement of 32 of the 160 units impacted, representing 2,901 MW of capacity. It is further expected that the upgrades associated with 24 of these 32 units may be able to be implemented before 2015 if these upgrades were committed to by the end of 2011 or early in 2012. These involve upgrades such as capacitor bank installations, short lower voltage transmission line additions, modest reconductoring jobs, or transformer upgrades at existing stations.

The 2,919 MW retirement scenario considered the possible retirement of 45 units at 22 stations. 15 of these units representing 1237 MW are expected to require transmission system upgrades if retired. The total cost of these upgrades is about $80 M with the exception of the one plant with the estimated $500 M upgrade. It is expected that the $80 M of upgrades may be able to be implemented before 2015, again, if these upgrades were committed to by the end of 2011 or early in 2012.

None of the impacted units are designated Black-Start units. Sixty-eight (68) units are on primary cranking paths of system restoration plans, and the restoration plans should be updated due to the unavailability of these units. One plant is identified in the system restoration plan as critical for voltage support for nuclear power plants, and alternative plans will need to be developed that would not require these units.

# 10. Conclusion

The proposed EPA regulations will have an impact on the MISO system. It is up to the individual utilities to make the decisions on the retrofit or retirement decision. Many factors will need to be considered for this decision. They will include the cost of retrofit compliance, the cost of replacement capacity to meet Resource Adequacy requirements and the cost of energy on the system. Asset owners will also consider the cost of needed transmission upgrades, transmission congestion, timelines for compliance and future regulatory uncertainties such as carbon. MISO addressed these issues, but the results should be considered indicative to what could happen throughout the system. Asset owners will have to take all the factors into consideration.

This study identified a set of retirements based on a low natural gas price and various levels of carbon costs. Future natural gas and carbon prices have a direct correlation to the amount of retirements that will occur. Low gas prices encourage retirement of coal units because the replacement energy costs are not significantly higher. However, as gas costs increase, the decision for retirement may become less. Increase of costs for carbon compliance could increase coal unit retirement. Uncertainty around the future economic and regulatory conditions makes the retirement decisions difficult for the asset owners.

This analysis identified impacts on the resource fleet, system energy costs and the Transmission System. Under tariff reliability requirements, it is required that the bulk power system will maintain generation and transmission reliability. The EPA regulations add a constraint to the system that must be mitigated. Because of this, the risk of implementing the EPA regulations is not reliability, but the cost to maintain that reliability. Table 10-1 shows those costs identified within the MISO analysis.

| | 2,919 MW of Retirements | 12,652 MW of Retirements |
|---|---|---|
| Energy Cost Impacts without Carbon | $1.0/MWh | $5/MWh |
| Energy Cost Impacts with Carbon | $31.0/MWh | $30/MWh |
| EPA Compliance Retrofit Capital Costs | $28.2B | $22.5B |
| New Capacity Capital Fixed Charges | $1.7B | $9.6B |
| Fixed O&M Capital Costs | $1.1B | $0.0B |
| Transmission Capital Costs | $0.6B | $0.9B |
| **Total Capital Costs** | **$31.6B** | **$33.0B** |

**Table 10-1: System costs because of implementation of EPA regulations (2011 dollars)**

The 20 year costs for both sets of retirement scenarios are less than 10 percent different in this analysis. The primary difference in the outputs is where the costs are allocated. It is difficult to judge which plan is "better." This analysis reviewed the uncertainty around carbon regulation. To determine a more likely scenario between the two would require additional iterations of analysis around gas, carbon and other sensitivity evaluation. The cost of energy within the system contains feedbacks that the models used can't capture. For example, higher dependence on the natural gas fleet could result in higher natural gas prices. At some point, equilibrium will exist at a point with a proper balance of new natural gas resources and gas prices.

In addition to the cost impact there is a compliance risk with the proposed regulations. Additional investment in the generation fleet and the Transmission System will maintain bulk power system reliability – at a cost. However, another risk not addressed directly that must be recognized is the time in which units must be compliant. If it is determined that capacity should be retired, it would take at least two to three years to build a combustion turbine to replace it. Also, if Transmission System reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to become operational. The time from final regulation to compliance may be difficult for some situations throughout the system.

Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed compliance equipment. Given the tight window for compliance, much of the capacity on the MISO system will need to take their maintenance outages concurrently. The need to take multiple units out of service on extended outage has significant potential to impact resource adequacy.

# 11. Next steps

This analysis did not take into account sensitivities around demand and energy growth or wind penetration. Higher demand and energy growth may result in greater impacts around the cost of system compliance, as new resources to replace any retirement selection would affect the system capital investment and energy costs at an earlier time. Increased wind resources could suppress energy costs on the system, making coal retirements more likely. Both conditions could impact the amount of retirements further.

Additionally, further iterations around the cost of natural gas and carbon need to be evaluated with the identified retirements from this analysis. This would provide additional information on the robustness of the results provided for what the future may hold for costs on the system.

This analysis also assumes that the natural gas Transmission System is sufficient for the increased dependence on natural gas. This may or may not be true. This question is being pursued in a separate study to determine if there are costs being left out of the analysis.

Finally, a follow-on study specifically focusing on the CSAPR is underway.  This evaluation will look at the near term impacts that will be associated with meeting the 2012 through 2014 system requirements for the production of $SO_2$, $NO_X$ and Seasonal $NO_X$.

# Montana-Dakota Utilities Co.
# Summary of Additional EGEAS Cases

## 2011 IRP Base

- The Base Case results from the 2011 Integrated Resource Plan

## Additional Case 1 – La Capra Modified Base

Used the "Base Case" with the following additions:

- Included two additional responses from the 2010 MDU RFP to be considered as resource alternatives:
  - 150 MW North Dakota wind proposal
  - 176 MW Illinois combustion turbine proposal
- Lowered the forced outage rate for the 43 MW Combustion Turbine from 22.31% to 6.45%
- Lowered the capital cost for the self-built wind options from $2,400/kW to $1,750/kW
- Assumed the federal production credit was extended through 2020 as compared to 2012
- Set the fixed O&M for the purchased wind energy option to $0 from $12/kW-yr
- Lowered the variable O&M for the self-built combined cycle option to $3.00/MWh from $6.00/MWh

## Additional Case 2 – La Capra Modified Base without ND Wind and IL Proposal

Used the same assumptions as the "Additional Case 1" except:

- Removed the 150 MW North Dakota proposal
- Removed the 176 MW Illinois combustion turbine proposal

## Additional Case 3 – La Capra Modified Base with IL Proposal and no PTC extension or ND Wind

Used the "Base Case" with the following additions:

- Included the 176 MW Illinois combustion turbine as a resource alternative
- Lowered the forced outage rate for the 43 MW Combustion Turbine from 22.31% to 6.45%
- Set the fixed O&M for the wind energy option to $0 from $12/kW-yr
- Lowered the variable O&M for the self-built combined cycle option to $3.00/MWh from $6.00/MWh

## Additional Case 4 – La Capra Modified Base without IL Proposal and no PTC extension or ND Wind

Used the "Base Case" with the following additions:

- Lowered the forced outage rate for the 43 MW Combustion Turbine from 22.31% to 6.45%
- Set the fixed O&M for the wind energy option to $0 from $12/kW-yr
- Lowered the variable O&M for the self-built of the combined cycle to $3.00/MWh from $6.00/MWh

## Montana-Dakota Utlities Co.
## EGEAS Additional Case Results

| Year | 2011 IRP Base | Additional Case 1<br>La Capra Modified Base | Additional Case 2<br>LaCapra Modified Base without ND Wind and IL CTs | Additional Case 3<br>La Capra Modified Base with IL CTs and no PTC extension or ND Wind | Additional Case 4<br>La Capra Modified Base without IL CTs and no PTC extension or ND Wind |
|---|---|---|---|---|---|
| 2011 | | | 4-Wind Built[2] | | |
| 2012 | | | | | |
| 2013 | 1-Purchase | 1-Purchase | | 1-Purchase | 1-Purchase |
| 2014 | 2-Purchase | 2-Purchase | | 2-Purchase | 2-Purchase |
| 2015 | 2-CT43, 2-DSM, CT88, BGS AQCS | 2-DSM, BGS AQCS, IL-CT, ND Wind | CT43, 2-DSM, CT88, BGS AQCS | 2-DSM, BGS AQCS, IL-CT | 2-CT43, 2-DSM, CT88, BGS AQCS |
| 2016 | | | | | |
| 2017 | | | CT43 | | |
| 2018 | CT43 | | | | CT43 |
| 2019 | | | | | |
| 2020 | 4-Wind | | | 4-Wind | 5-Wind |
| 2021 | | CT43 | CT43 | CT43 | |
| 2022 | CT43 | | | | CT43 |
| 2023 | | | | | |
| 2024 | | CT43 | CT43 | CT43 | |
| 2025 | CT43 | | | | CT43 |
| 2026 | | | | | |
| 2027 | | | | | |
| 2028 | CT43 | CT43 | CT43 | CT43 | CT43 |
| 2029 | | | | | |
| 2030 | | | | | |
| NPV[1] | $3,723.72 | $3,329.80 | $3,630.46 | $3,460.78 | $3,707.86 |

1 - NPV in millions of dollars
2 - PTC are modeled in EGEAS as negative variable O&M until 2030 in the model

*CT43 - 33.4 PRC (43 MW) Combustion Turbine
*CT88 - 82.3 PRC (88 MW) Combustion Turbine
*CC - 132.5 PRC (140 MW) Combined Cycle
*Base Load - 27.7 PRC (30 MW) Coal-fired Generation
*DSM - 12.5 PRC (12.5 MW) Demand Side Management
*BGS AQCS - Big Stone Air Quality Control System
*Wind - 25 MW Wind (Purchased Energy)
*Purchase - 10 PRC (10 MW) Capacity Purchases
*Wind built - 30 MW Wind (Self-built)
*IL-CT - 176 MW Illinois Combustion Turbines
*ND Wind - 150 MW wind energy

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**Montana-Dakota Utilities Co.**

**Comparison of MDU 88 MW CT versus Tilton Proposal (in $1,000)**

Including Additional WAPA IS Transmission Charges

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