Electric and Natural Gas Coordination Case Study

The MISO Proactive Approach
A Collaborative Effort between the Natural Gas Industry, the RTO and its Stakeholders

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Introduction: The Value of Analysis with Real Data - Lin Franks

One of the challenges faced by Regional Transmission Organizations (RTO) and their Stakeholders is obtaining or providing real information relative to plans to modify the topology of the footprint in future years. Transmission Expansion processes do not include the Stakeholder forward plans for generation if that generation has not entered the RTO interconnections queue process and progressed to the determined milestone. At the source of this omission is the fact that Stakeholders are subject to disparate regulatory processes and have vastly different business models. Some are required to produce Integrated Resource Plans by their State Commissions; some of these plans are public, others are not. Some are free to plan for future resource adequacy however they determine prudent and still others must determine a commercially viable need.

The infrastructure encompassed by the RTO footprint is in part regional in nature and in part local. For the regional transmission system, information is collected through transmission expansion processes governed by the tariff for transmission projects and for generation for which an executed Generator Interconnection Agreement has been executed. For the remainder of future generation, the RTO must forecast future need and location on its own. For generation and transmission projects that are local or subject to state regulations and/or not subject to the tariff, a Stakeholder may not be permitted to disclose the information when actually needed for studies of future years until later in the planning process…too late to be included in the RTO’s model.

From April 16, 2015 through the end of 2017, all Stakeholders subject to complying with the Environmental Protection Agency’s (EPA) Mercury and Air Toxics Standard (MATS) will be planning outages at the same time. This is an unprecedented event for this industry. The outages are for retrofits and repowering as well as retiring a set of coal-fired generating units. Therefore, in order to prepare for this period and keep the lights on requires advanced notice of outage plans as well as the specific location of replacement generators and if natural gas fired, which pipeline or LDC will serve the unit. Some of this information is known to the asset owners at this time and other information such as choice of natural gas provider is not.

Maintaining reliability in this compliance period requires a clear picture of the plans of all asset owners in the footprint. Economically estimated information will not provide a reasonable basis for addressing the challenges. For example, one might assume for modeling purposes that a replacement generator might be installed at the same location as retiring generators. This is not always the case. Generally speaking if a generation-owning entity is retiring a set of coal-fired generators, this entity will probably replace them with one large combined cycle generator (CCGT). The retiring generators may be in various locations, so which location will the CCGT occupy? If a generation owner is using a set of leases for the replacement generation formerly occupied by coal units, often the owner may need a period of 3-12 months to remove coal piles, ash ponds and even railroad spurs before the replacement unit can be built. At this point in time, most if not all have a plan.

Knowing this type of specific information several years in advance of the compliance period provides the RTO and its Stakeholders with valuable knowledge of which days reliability might be at risk and time to
mitigate all or part of those risks. The consolidated output of the related analysis is very valuable information for policy and law makers as well. This real information gives policy and law makers an opportunity to prevent the identified risk of material loss of reliability, such as a potential black out resulting from their actions.

Because this period between April 16, 2015 and the end of 2017 is unprecedented, processes to collect the requisite data needed for appropriate analysis do not exist in RTO tariffs and Business Practice Manuals. RTO tariffs do not contemplate this type of event and even if they did the processes might be trumped by one or more competing regulatory process. If a tariff gives the RTO an ability to deny or reschedule an outage, but the Asset Owner requires that outage period to meet its EPA deadline, chances are the Asset Owner will take the outage regardless of the tariff and potential reliability consequences.

Given the potential risk to reliability, MISO and its Stakeholders have devised ways and means to provide MISO with their confidential information: advanced notice of compliance plans, outage plans, and more as needed so that what is modeled uses topography as close as possible to reality. While Stakeholders typically want different results from a MISO process due to their own business incentives, with respect to keeping the lights on, all have the same goal. The processes that are key to our collective success in addressing this potential threat to reliability are all cooperative. No regulatory or tariff hammer is needed. This is not a nail.

The Midcontinent ISO (Formerly: The Midwest ISO)

The Midcontinent Independent System Operator (MISO) exists to provide an independent platform for efficient regional energy markets. Since 2001, MISO has fostered wholesale electric competition in the region, created greater system reliability and established coordinated, value-based regional planning.

MISO’s wide range of services began simply enough. Several transmission owners recognized the benefits of Federal Energy Regulatory Commission’s (FERC) vision to form an independently operated regional transmission system, voluntarily coming together in 1998 to establish MISO.

FERC accepted MISO’s organizational plan and initial transmission tariff on Sept. 16, 1998, and then approved the MISO as the nation’s first Regional Transmission Organization (RTO) in December 2001. On Dec. 15, 2001, MISO began reliability coordination and regional planning services, and initiated procedures for regional planning, generation interconnection, maintenance coordination, market monitoring and dispute resolution.

On Feb. 1, 2002, FERC accepted MISO’s Open Access Transmission Tariff (OATT), allowing it to also provide regional transmission services and eliminate pancaked rates.

On April 1, 2005, MISO launched the Energy Markets and began centrally dispatching generating units throughout much of the central United States based on bids and offers cleared in the market. MISO also began administering a market for tradable Financial Transmission Rights.
With the launch of the MISO Ancillary Services Market (ASM) on Jan. 6, 2009, MISO also became the region’s Balancing Authority, instructing local balancing authorities on operation of resources. Integration of ASM into market operations made possible the central dispatch of regulated reserves, spinning reserves and supplemental reserves based on bids and offers cleared.

Electric and Natural Gas Coordination at MISO - John Lawhorn, J.T. Smith and Tessa Haagenson

EPA Impact Analysis

In October 2010, MISO initiated a study to understand the implications of four draft EPA Rules under consideration, including:

1. Clean Water Act (CWA): Section 316(b), Cooling Water Intake Structures (rules pertaining to cooling water intake restrictions for power plants drawing cooling water from lakes or rivers)
2. Mercury and Air Toxics Standards (MATS), formerly known as EGU Maximum Achievable Control Technology (MACT)
3. Coal Combustion Residuals (CCR)
4. Clean Air Interstate Rule (CAIR), as proposed in 2010; this regulation was finalized as the Cross State Air Pollution Rule (CSAPR) in July 2011

MISO’s study supplemented a North American Electric Reliability Corporation (NERC) analysis¹ published in October 2010. The NERC study was extensive but it did not examine financial implications or provide the detail needed at the MISO level. MISO used the Electric Power Research Institute (EPRI) Electric Generation Expansion Analysis System (EGEAS) model to perform a wide array of sensitivity analyses surrounding the four proposed rules, in combination and individually. Study assumptions were vetted by the Planning Advisory Committee, a Stakeholder body. Through this open and collaborative process, MISO produced study results² in October 2011.

The analysis identified from 3 to 23 GW of at-risk coal capacity for retirement, and potential electric rate increases of 7.0 to 7.6 percent. As shown in Figure 1, almost the entire fleet within the MISO footprint (currently, the MISO Midwest footprint) was impacted by at least one of the four proposed rules.

Although approximately 32% of current generation resources (installed capacity basis) within the MISO footprint are gas- and oil-fueled, most of the energy production has historically come from coal, nuclear, and wind resources. Over the past few years, energy production from gas-fired resources has slowly increased, while reliance on coal has decreased. Figures 2 and 3 illustrate this transitioning resource mix, with the latter presenting results of resource forecasts from MISO Business-As-Usual models, taking into account coal unit retirements and assuming sustained competitive gas prices.

Figure 1. Projected Impacts of Proposed EPA Regulations on Coal Units in the MISO Footprint

Figure 2. Historical Contribution by Fuel Source to Energy Production in MISO
With the potential for high levels of coal capacity retirement, the implications of fuel switching risk associated with a significant shift from coal to natural gas became apparent.

To gain a better understanding of the transitioning resource mix, MISO began soliciting information from asset owners on their strategies for compliance with the proposed regulations through a Quarterly Survey. The Survey encompasses questions on gas and coal units, including plans to retrofit or retire individual units, fuel contracts, and permits and compliance extensions. Survey responses are aggregated and provided on a footprint-wide level. The most recent Survey results are presented in Figures 4 through 7.
**Figure 4.** Coal-fired Generation Capacity in MISO Midwest Impacted by EPA Regulations (GW)

**Figure 5.** Retrofits and Outages by Technology

<table>
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<tr>
<th>Technology</th>
<th>ACI</th>
<th>DSI</th>
<th>FGD</th>
<th>Baghouse</th>
<th>SCR</th>
<th>ESP</th>
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<td>Work Required (GW)</td>
<td>31.7</td>
<td>13.2</td>
<td>9.2</td>
<td>6.5</td>
<td>6.1</td>
<td>4.2</td>
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<tr>
<td>Work Scheduled (GW)</td>
<td>23.5</td>
<td>10.9</td>
<td>7.4</td>
<td>6.4</td>
<td>5.0</td>
<td>4.2</td>
</tr>
<tr>
<td>Work Contracted (GW)</td>
<td>12.7</td>
<td>6.9</td>
<td>6.9</td>
<td>3.9</td>
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<tr>
<td>Outage Scheduled (GW)</td>
<td>18.8</td>
<td>7.7</td>
<td>7.4</td>
<td>8.2</td>
<td>5.0</td>
<td>4.1</td>
</tr>
</tbody>
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ACI = Activated Carbon Injection  
DSI = Dry Sorbent Injection  
FGD = Wet Flue Gas Desulfurization  
SCR = Selective Catalytic Reduction  
ESP = Electrostatic Precipitation
While progress is being made by asset owners, a significant amount of uncertainty surrounding the impacts of compliance still exists. This increases the challenge of planning for future system operation.

Gas-Electric Coordination at MISO

Figure 8 gives a timeline of gas-electric coordination at MISO, detailed in the following sections.
Phase I Gas Study

In October 2011, after an open bid process to choose a gas consultant, MISO initiated a gas study to investigate two questions:

1) Is gas supply adequate for a major shift in electric generation resources from coal to gas?
2) Can the current gas infrastructure accommodate projected demand increases?

An answer to the first question came back quickly in the affirmative due to the proliferation of hydraulic fracturing. The second and more interesting question of pipeline deliverability has taken MISO on a journey of discovery over the past 18 months.

MISO hired Greg Peters, President of Envision Energy Solutions, to perform a Modified Backcast Analysis (MBA). The MBA modeling methodology held natural gas pipeline infrastructure and flow patterns static, while forecasting coal unit retirements and new gas-fired generation needed to meet reserve margin requirements. Unit capacity factors were supplied by MISO, based on results of EGEAS (Electric Generation Expansion Analysis System) simulations using the same database as for the EPA Impact Analysis. This information was produced on an annual basis for a 20-year time horizon and assumed a $4.50/MMBtu price of gas in 2011. Capacity factors were translated to fuel burns and aggregated at the pipeline level. This data served as inputs to determination of the future adequacy of the existing gas pipeline infrastructure of the major interstate pipelines in the MISO footprint, shown in Figure 9.
The study\(^3\) was published February 22, 2012, with the following major conclusions:

1. Increasing operational flexibility and additional gas pipeline infrastructure is needed to accommodate fuel switching.
2. Timing for development of new pipeline infrastructure is an issue of concern:
   a. Planning, siting, regulatory compliance and construction of new main line gas pipelines will be on the order of 5-6 years, if started now.
   b. The compliance deadline timeframe for the Mercury and Air Toxics Standards (MATS) rule is 3-5 years (i.e. 2015 deadline with the possibility for federal and state 1-yr extensions to 2017).
3. The cost impact associated with pipeline infrastructure development in the Midwest is approximately $3 billion.

**Phase II Gas Study**

By the time the Phase I Gas Study was published, natural gas prices had dropped to around $2/MMBtu. Given the significant decrease over the previous five-month period, MISO undertook Phase II of the gas study. The key difference between the Phase I and Phase II studies is the modeled price of natural gas: $4.50/MMBtu for Phase I base year gas price and $2.50/MMBtu for Phase II. Prior MISO analyses found that gas-fired generation becomes competitive with coal-fired generation in the MISO region in the

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$3/MMBtu range. As expected, the lower gas price resulted in significantly higher gas unit capacity factors, in many cases exceeding pipeline design limitations. The Phase II Study\(^4\) was published in July 2012 after review by pipeline and gas supplier industry groups. All comments received were published in the report. A general point of disagreement expressed by the pipeline community was the use of the Modified Backcast methodology.

Figure 10 provides a comparison of historic vs. forecasted capacity factors\(^5\) for the gas fleet in the MISO footprint. These numbers illustrate the expected growth in gas demand as a result of coal generation retirements associated with EPA rules, in conjunction with varying gas prices. According to Phase II results, capacity factors under expected gas fleet operations in a low gas price future could increase six fold from historical operation.

**Figure 10.** Phase II Results: Capacity Factors for Historic vs. Forecasted Levels of Gas Fleet Operation

The results of the Phase I and Phase II Gas Studies helped drive the conversation with MISO Stakeholders and the gas industry on gas-electric interdependency. To identify differences in gas infrastructure and demands across the footprint, MISO organized a series of zonal gas-electric workshops over the summer of 2012. These workshops included presentations from Stakeholders as well as the gas industry, and in some cases were jointly facilitated by MISO and its Stakeholders. The workshops revealed a significant knowledge gap between the gas industry and the electric industry.

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\(^5\) Capacity factor is a measure of the actual energy output of a generator divided by the maximum potential energy output of that generator, generally given on an annual basis.
same terminology carried different meaning depending on which industry was providing the context, complicating basic discussions about infrastructure, regulatory constructs and business operations.

During the same timeframe, MISO recognized it required a much deeper understanding of the gas industry overall and specifically of the pipelines in the footprint. MISO arranged meetings with individual gas pipeline companies, and MISO Operations and Planning staff interfaced with their gas pipeline counterparts.

The gas-electric conversation continued to gain momentum but lacked an official forum. In October of 2012, the Electric and Natural Gas Task Force was formed jointly by MISO and its Stakeholders. Initial challenges for the group included identification of its functions, as well as its purview. Misunderstanding of the role of the group persisted the first few months of existence. The Task Force has since proved an effective vehicle for cross-industry education and discussion. The group meets monthly and has had active participation across Stakeholder groups, as well as from the natural gas industry.

**Phase III Gas Study**

MISO is currently undertaking a third phase of its gas analysis. This investigation, performed jointly by Envision Energy and Bentek, includes an update to the Phase II Modified Backcast Analysis, a Forward Balancing Analysis of MISO Midwest, and a corridor flow analysis of the Southern portion of the MISO footprint. The Forward Balancing Model will take into account historic gas pipeline flows and will project future pipeline capacity, based on changing industrial and electric generation demands, as well as changing pipeline flow patterns. In combination, these analyses will provide a comprehensive view of the adequacy of the gas infrastructure throughout the MISO footprint to handle increasing demand from gas-fired electric generators.

**Electric and Natural Gas Coordination Task Force - Lin Franks**

One of the results of MISO’s proactive efforts to identify the impacts an increase in reliance upon natural gas in the footprint was the creation of the Electric and Natural Gas Coordination Task Force (ENGCTF) in October of 2012. The ENGCTF provides a forum for electric and natural gas industry experts and interested MISO stakeholders to identify challenges and develop recommendations to comply with regulatory deadlines, investigate market impacts, and manage on-going operations with an increasing reliance upon natural gas while ensuring the reliability of the electric system. The task team is chartered to work with natural gas pipeline experts; local distribution companies (LDCs) and other parties to develop approaches to resolve identified challenges. The task force will leverage existing MISO stakeholder task forces, subcommittees, and working groups as well as the knowledge collected during MISO zonal gas-electric workshops conducted in 2012 to begin the focus on the interdependency between the electricity and natural gas industries.

Within the Stakeholder process at MISO this group is unique in that it actively solicited the participation by all interested parties in the natural gas industry. While the natural gas industry participants are not currently MISO members or market participants and therefore do not have “voting” rights under the Stakeholder Governance Guide, this task force requests and considers the input of the gas industry
participants in determining the appropriate path to address issues. At the request of some members of the natural gas industry, a path toward membership in MISO has been identified for non-electricity participants if they wish to use it. However, membership is not a requisite to their ability to be heard and have influence over direction relative to coordination.

The Task Force identified four (4) areas of potential risks to work on 2013. They are:

1. **Issues Related to Resource Adequacy**: Over the past few years, MISO has seen a shift in energy contribution by fuel type, including a decrease from 78% contribution by coal resources to 68%, and an increase from 3 to 9% by gas-fueled resources over that same period (2009 to 2012). MISO expects that this trend will continue with retirements of coal capacity and sustained low natural gas commodity prices. With increased reliance on gas-fired generation comes increased dependency upon natural gas supply and delivery. MISO and some MISO stakeholders are concerned that there may be an increased probability of lost load resulting from gas fired generators inability to access fuel during peak energy operating conditions. The fuel risk to gas fired generators includes both transportation and supply. MISO’s Emergency Operating Procedures require that firm load be shed, on a pro rata basis, over the entire energy deficient area. Thus, if accredited as a planning resource, gas fired generator outages may impact stakeholders other than the generator owner. While gas-fired generation availability has not negatively impacted reliability to date, increased reliance on gas-fired generation and in turn increased reliance on the natural gas system may result in reliability risks. There is broad agreement that the responsibility for fuel procurement lies with the generator, but there is no current conclusion that increased reliance on natural gas generation poses a material reliability risk to the MISO footprint or that the current rules related to capacity accreditation need to change. It is anticipated that later this year, the ENGCTF will have collected sufficient fundamental knowledge of the fuel impacts upon generator availability to send the information onto the Supply Adequacy Working Group for stakeholder determination of capacity credit for gas fired generators and determination of appropriate tariff requirements for firm pipeline capacity and fuel supply.

2. **Misalignment of the Natural Gas and Electric Operating Day and Scheduling**: The operating days for natural gas and electric industries are not aligned. In addition, the timeframe for pipeline nominations and the timeframe during which generators receive their bid confirmations in the MISO Day-Ahead market are disconnected. Natural Gas nominations have to be submitted many hours before electric generator unit commitments are made. Time differences between the Gas Day and the Electric Day result in scheduled gas which straddles two electric days, which requires two days of gas nominations to cover one day of electric generation. For generation owners, this translates to fuel risk. For those geographic areas rich in infrastructure including storage, many products and services are available to mitigate that risk. Areas without sufficient pipeline infrastructure and storage are more exposed to the risk. In MISO as in other RTOs, one solution under consideration is the acceleration of the timetable for market clearing. With advancement there will be some loss of confidence in the forecast for real-time so these decisions are not taken lightly. In addition, as the MISO footprint includes a
statistically material quantity of intermittent resources that add operational and forecasting difficulty in real time, Stakeholders and MISO must give serious consideration to any additional loss of forecasting ability due to clearing time advancement before making any changes to process or tariff.

- **Coordinated Operations**: Fuel disruptions in the MISO footprint can have a negative impact upon the reliability of the transmission system. In advance of the increase of natural gas fueled generation in the MISO footprint, the ENGCTF will investigate the current coordination processes between natural gas pipelines and LDCs, generation owners and MISO to identify any potential operational concerns that might be mitigated by enhanced coordination. Initially this issue was identified by task force participants as relative to emergency operations only. However, an emergency operations process already exists whereby MISO Operations acquires specific fuel supply information from the generator operator during emergency situations, RTO-OP-021-r5. As a result of the existence of this protocol, this issue was broadened to address day-to-day operations and outage coordination.

- **Continued Reliability through Market Signals**: Locational Marginal Prices (LMPs) provide appropriate signals relative to transmission congestion; however LMPs do not currently support inclusion of the cost of firm natural gas transportation or for firm fuel supply. In order to economically incent appropriate behavior in the markets, generators require a reasonable ability to obtain a revenue stream to cover their costs collectively through energy markets and the capacity construct. The Electric and Natural Gas coordination Task Force will gather the fundamental and technical information requisite for existing stakeholder task forces, committees, and working groups to develop appropriate tariff and business practices changes to modify these price signals. Issues that may need to be addressed include but are not limited to: Incentives relative to generator availability that may be related to fuel availability and recovery of the cost of firm transportation and supply; potential removal of offer caps during capacity emergencies; recognition of various Over the Counter products providing flexibility in firm service. While this issue relates to Resource Adequacy, it is limited to ways and means to modify the price signals to continue to assure reliability with a greater reliance upon gas fired generation, including Combined Cycle Gas Turbines dispatched as base-load generation.

A primary focus of the group is cross-industry education and knowledge gathering. A sampling of specific topics covered at Task Force meetings this year includes:

- America’s Natural Gas Alliance (ANGA): Natural Gas Pricing/ Supply and Regulation; Impact of potential restrictions on fracing of shale gas deposits.
- American Gas Association (AGA): Gas Day/Electric Day Scheduling; AGA point of view on potential changes to resolve the challenges of differing scheduling and clearing practices.
- CME Group: Changing Relationship between Natural Gas Prices and Power Prices
Various gas pipeline company presentations on system configuration, operation, regulatory environment and culture.

The Task Force is also following the activities of similar stakeholder groups at other Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), as well as proposed and on-going gas-electric studies, and Federal Energy Regulatory Commission (FERC) gas-electric activities.

The first issue to be defined by the ENGCTF and recommended to be addressed by another stakeholder working group is an investigation of the impact of fuel availability or lack thereof on the footprint and resource zone loss of load expectation. This was identified within the Issues Related to Resource Adequacy category. Ideally, complete knowledge of the interconnection point of all new generation and repowered plants as well as knowledge of their chosen fuel supplier would be used in this analysis. Because not all who are building new generation or repowering existing coal plants are yet ready to make this part of the plan public, obtaining that type of information could take years. However, it is possible to collect planned information from stakeholders on a voluntary basis as well as their top three fuel supplier options at this point in time so long as the information remains confidential and is non-binding. Conducting such an analysis is one of the recommended steps before determining any tariff changes relative to capacity accreditation and/or a requirement to procure firm transportation and supply for the winter peak. First we must determine if there is a potential problem. As the MISO footprint is generally rich in natural gas infrastructure, the situation is very different from the infrastructure-deficient New England ISO.

As this study is dependent upon fuel supply availability and knowledge transfer from the natural gas industry, the ENGCTF will coordinate with the Loss of Load Expectation Working Group (LOLEWG) on a continuous basis as the project is scoped, the methodology is developed, and the analysis is performed. The timeline for this effort has not yet been determined, but since the studies are time consuming and must fit within the working plans of the LOLEWG, we do not anticipate definitive results until 2014.

An issue that was raised in the Supply Adequacy Working Group that may require some coordination through or with the ENGCTF is coordination of generation outage schedules for the period April 2015 through the end of 2017. To determine if sufficient generation will be online for every day of that period to meet the demands of load requires another cooperative stakeholder effort to gather real data relative to the EPA compliance-driven outage schedules of Generation Owners. As generator outages can impact natural gas pipeline reliability as well as MISO reliability, this effort will be closely monitored within the Coordinated Operations effort.

EPA Compliance Planning - Lin Franks

The MATS deadline is April 16, 2015\(^6\). The EPA delegated to the State environmental agencies the ability to extend that deadline to April 16, 2016 for the utilities under their jurisdiction. There are two other avenues that potentially could provide more time to comply. The first is an Agreed Order that a generation owner can request from the EPA. An Agreed Order is not an extension of the deadline, but is

\(^6\) [http://epa.gov/MATS/actions.html](http://epa.gov/MATS/actions.html)
an agreement not to pursue civil penalties. It does not protect the generation owner from legal action by others. The EPA cannot issue an agreed order until after April 16, 2015. To request such an Order from the EPA requires that the requestor has provided its compliance plan to the North American Reliability Corporation (NERC) designated Planning Authority by April 16, 2013. For the EPA to grant the request requires that the reliability coordinator agree it is necessary to continue to operate the specific unit(s) beyond the deadline to maintain reliability. For most of its members, MISO is the reliability coordinator.

The second means to extend is a Presidential Order. This is far more difficult and is not an appropriate avenue for an individual asset owner. If through all the studies and cooperative efforts to gather real data, MISO determines that reliability is threatened for all or part of the footprint for which it is responsible, it could request a Presidential Order to extend the deadline beyond April 16, 2016. Such a request requires extensive supporting evidence and would only be successful if the EPA agreed with MISO’s analysis. It would be helpful to the argument if FERC and NERC also agreed.

Many utilities watched the evolution of MATS closely modifying their own internal analysis as changes occurred. The process of MATS development and utility internal studies occurred over a 4 year period. During that period, studies were conducted on a somewhat continuous basis to determine the most efficient and cost effective ways to approach compliance targets. The resulting plan for many utilities includes a combination of retirement of older coal fired units, repowering of some units to use natural gas as a fuel source, and of course installation of equipment to reduce emissions on others. In general these plans are not static, but change constantly as a result of technology, equipment availability, other regulatory impacts, and more. As a result of the dynamic nature of the “plan”, some utilities take longer than others to determine which approach to take with each unit at risk.

If a retirement is planned and replacement generation is selected as the appropriate means to meet the EPA requirements, then a state regulated utility must meet its state requirements. Some but not all must be granted permission to retire a unit; all are required to obtain a Certificate of Public Convenience and Need (CPCN) from the state commission. The process for obtaining a CPCN varies a bit from state to state but in general it takes around 2 years to complete the process. The CPCN is generally required before breaking ground.

Depending upon the state, before deciding to build its own replacement generation, a utility may be required or expected to solicit through a third party Request for Proposal (RFP) process alternate solutions for the defined need. That process in itself can take from 6 months to a year to complete and is generally a precursor to filing for a CPCN.

The selected solution must then go through the MISO Interconnection Queue Process, pay the requisite fees and participate in the study processes. Depending upon the queue status and path chosen, this process can take from 1-2 years to complete; the end state is an executed Generator Interconnection Agreement that is filed with FERC.

Often the retirement of a unit and/or the interconnection of a new unit will drive the need for transmission system upgrades. Some upgrades may be needed to improve the ability to import energy
from the market for the period between retirement of the target unit(s) and the in service date of the replacement generation. Others may be needed to meet identified system contingencies or to assure deliverability to a target load. These identified transmission projects must then be included in the MISO Transmission Expansion Plan (MTEP), meeting all deadlines for for inclusion.

Projects that are cost shared, not defined as Generator Interconnection Projects and that did not meet the deadlines for inclusion in the MTEP13 may be exposed to the removal of the Right of First Refusal in Order 1000. If they are cost shared projects per the MISO tariff, then MISO will facilitate an RFP process to determine who is allowed to build the project(s). As the selection of developer is a precursor to filing for a CPCN, given the various regulatory processes that include public hearings and potentially protests, the in service dates of these required projects can be delayed up to 3 years. This timeline extension may challenge the developed EPA compliance plans as they include the elements needed to assure continued and reliable service to load.

When a utility’s analysis determines that the retirement of a coal fired plant is in the best interests of its customers, it is not a decision that is taken lightly. State regulated utilities have an obligation to serve their customers reliability and at a reasonable cost. The plans of state regulated utilities are scrutinized by several entities before they are implemented including the regulatory commission, formalized consumers advocates, state environmental agencies, the EPA, NERC, special interest groups and shareholders. If the plant to be retired is a union shop, then there may be separate negotiations to take place as well.

One consideration for retirement is that the plant is “out of the money” in the market, however that alone does not determine the choice. Retirement of some plants may necessitate large capital expenditures for transmission and facility upgrades to continue to reliably serve the needs of load. For state regulated utilities, recovery of the costs of needed transmission and facility upgrades as well as any costs related to generation additions as well as the other costs of EPA compliance such as retrofits and repowering require approval of a rate case. In many states, those costs cannot be recovered until the facilities are “in-service”. Essentially, these projects are “self-funded” until the rate case is approved by the state commission and the projects are in service. This is a multi-year timeline.

After the appropriate state, environmental, and MISO processes are completed then the asset owner can begin construction of the requisite transmission and facility upgrades as well building any new generation facility. At this point the utility has invested approximately four (4) years in following and studying the evolution of MATS; approximately two (2) years in obtaining a CPCN; 1-2 years in navigating the MISO interconnection queue; 1-2 years in navigating the MTEP process before it can begin construction. The construction timeline for transmission upgrades is in the range of .1/2-3 years for lower voltage projects to 2-4 or more years for larger voltage and longer mileage projects. The schedule for building a new CCGT can easily span 2 years from the CPCN award to placing the unit in service. Meeting the EPA deadlines and continuing to serve customers reliability at this point in the planning hinges upon outage schedules of the asset owners as planned for 2015-2017.

Interconnection Queue and other tariff and process challenges to consider: Eric Thoms
The amount of active generation in generator interconnection request study queues is often cited by some as an indicator or assessment of long term generation forecasts. However, traditionally these study queues see a high withdrawal rate and therefore a simple reference to how much active generation resides in a queue should not be the sole indicator used to provide certainty in long term planning.

As of May 24, 2013, there are 153 active Generator Interconnection Requests (GIR) in the MISO Generator Interconnection Procedure (GIP), or also known as the “queue”. These active requests comprise nearly 25,800 MW. However, over the past 10 years, approximately 68% of such requests in MISO have withdrawn, as compared to the total number of new requests that entered the queue over the same period. Figure 11 shows a year-by-year breakdown of withdrawal rates.

Figure 11. MISO Generator Interconnection Queue Trends

This high withdrawal rate was one of several reasons MISO conducted queue reforms both in 2008 and in 2012. As the chart shows, the withdrawal rates have improved over the last several years.

A further breakdown in understanding each RTO/ISO queue is required. As shown in Figure 12, of the approximately 25,800 MW active in the MISO queue, only 26% of the generation is in what’s known as the Definitive Planning Phase. This phase has a higher level of probability of achieving a Generator Interconnection Agreement (GIA) and ultimately a higher degree of certainty of eventually being constructed and going into service. The remaining generation has either just entered the GIP and is having a high level feasibility study be conducted, or a non-binding system planning and analysis study or has simply parked, for up to 18 months, until the developer is ready to provide and/or demonstrate
the readiness milestones necessary to proceed to the Definitive Planning Phase. These readiness milestones are an effort to increase the amount of certainty for generation in the queue.

Figure 12. Active MW in the MISO Generator Interconnection

An additional consideration is that generator interconnection queues may not reflect multiple entries of the same capacity. This is owed in part to the utility RFP process for new generation to serve load and/or meet future renewable energy mandates. It is not a requirement for generator developers to inform MISO that their request is in response to a specific utility RFP. The GIP is designed as an independent process to essentially enable all interconnection requests in achieving a GIA should the interconnection request customer or developer choose to do so. Often, an interconnection request that has achieved a GIA has a competitive advantage in responding to RFPs over those that do not.

Some entities who plan to build replacement generators may, either due to company policy or the expectation of their state commission, refrain from entering the queue until they have received a Certificate of Public Convenience and Need from their state commission. At best, the information on planned generation in the queue may be incomplete.

It is for these reasons that most long term transmission expansion planning takes into account generation from these queues that has actually achieved a GIA, thus providing a higher level of certainty.

Outage Coordination between April 16, 2015 and the End of 2017 - Lin Franks

From the voluntary, cooperative Stakeholder surveys of EPA compliance plan information conducted by MISO on a quarterly basis, we can expect that the replacement resources planned will be natural gas fired generation that will be placed in service between 2015 and 2017. To address retrofits, repowers, and retirements, generation outage requests are anticipated to increase significantly between 2013 and 2017. In addition to several generating units being retired in this timeframe, some generating units will require periods of outage for retrofit or repowering in addition to routine maintenance outage requests. MATS deadlines cause an unprecedented magnitude of outage requests in the same time period.
Traditionally outage requests are clustered in the shoulder months; to accommodate all needed outages while maintaining reliability and sufficient resources to serve load might necessitate some to be scheduled in peak months. Transmission expansion projects needed as one result of retirements, retrofits, and/or repowering may increase the number of transmission outages during the same time period as well. The potential exists for overlapping outage schedules to degrade the availability of energy from the market and therefore a potential shortage of energy to serve load for extended periods within the 2015-2017 timeframe. As the transmission grid is integrated, consideration of imports and exports from/to neighboring systems must be considered.

MISO and its Stakeholders are collaborating on development an appropriate methodology and process to first identify the risks at a daily granularity and then to proactively mitigate the periods of potential degradation of reliability. The first step is the provision of the forward outage plan of all generators for the 2015-2017 timeframe. The MISO tariff does not require that generation owners provide this information so far into the future. Once the information is collected and compared to the anticipated load for each day, it will highlight those days where insufficient generation is on-line to serve that load with the current collective outage plans.

The planning for EPA compliance and the resulting outage schedules is for many stakeholders already complete and agreements with contractors and vendors already executed. While the schedules are backed by $100s of millions of dollars of vendor and contractor contracts that may not have much wiggle room for amendment; where possible, Stakeholders can work together to assure adequate resources are in service to serve load. Routine maintenance planned may be either accelerated or postponed due to EPA driven outages. These modifications to outage plans are envisioned to be worked out by a core set of Stakeholder Asset Managers working cooperatively with MISO. While the individual outage plans are proprietary, the results should be provided to the broad Stakeholder community. Some may be able to provide energy from outside of the footprint to fill an identified gap or suggest alternate means to mitigate the potential risk.

The Asset Managers of Utilities typically plan for maintenance 5-10 years ahead. Depending upon the technology of the generator, one expects to perform maintenance on an 18, 24, or 36 month cycle and anticipate a turbine over-haul every 9-10 years. Individually each plan can be challenging since sufficient energy must be in service to serve load reliably at all times. The challenge becomes greater when all generation owners are attempting to schedule large numbers of outages driven by EPA deadlines into a compressed timeframe. All will individually plan to buy energy from the market to fill an individual system gap, but at this time, none know if generation deliverable to their specific load is planning to be in service when they need it. Generation outage schedules are subject to changes on a continuous basis due to changes in the timeline by vendors and contractors, other events outside the control of the generation owner, as well as some minor adjustments due to the business needs of the owner.
Independent Power Producers (IPPs) use a variation of the above process. Some do and some do not coordinate outage schedules with their host utility. They do not typically coordinate with tangential systems. They do not typically have a feedback loop in their processes that looks at company financial needs but might defer outages as part of a strategy to reduce capital and other costs or to optimize gross margin. IPPs generally use a 3 year cycle for maintenance with turbine over-hauls on a 6-9 years cycle.

The ad hoc group of Stakeholders working cooperatively with MISO on this effort recommends that they form a group of a of Asset Managers to work directly with during the period 2015-2017 to mitigate outage issues that threaten the reliability of the system or service to load. This is similar to the coordination between Stakeholders and MISO relative to outages currently. The difference being the higher volume of outages and the expected increase in real time adjustments needed.

Because outage schedules are not static for that period today, the group requests that the studies be performed frequently and presented in a public forum by MISO. The core group of asset managers should discuss potential ways and means to mitigate any identified risk to reliability as part of the planning. However, the further into the future, the lower the confidence that the mitigation planned will adequately resolve the issue.
Where no mitigation appears to be ineffective by moving outages or where mitigation depends upon continued operation of units scheduled for retirement, the group recommends that MISO supply a written report of their findings to the owner of the unit. This report can then be used as MISO’s support for an Agreed Order from the EPA for that Generation Owner and the specific generating unit should the owner decide to pursue the Order.

Modeling the topology and business environment of the future - John Lawhorn

Long-Term Reliability Assessments have highlighted significant increases in gas-fired generation to meet increasing electric demand, replacing retiring coal-fired generation, and play a growing role in offsetting the variability and uncertainty associated with renewable resources. As variable generation increases, swings in variable generation may call for dispatch of gas-fired generation at a larger and less predictable rate.

As such, regional analyses should be conducted to include natural gas pipeline capabilities to respond to gas-service needs of generators now and into the future and ascertain fuel disruptions that could adversely impact bulk power system reliability. This analysis should address the infrastructure (supply, demand, pipeline capacity, changes in pipeline flows and operations, storage, etc.) and conditions that impact the natural gas infrastructure deliverability to current and potential gas fired power generation. Analyses should include impacts of severe contingencies on various parts of the natural gas system(s) and the impact those contingencies have upon gas capable generators.

The integration of the MISO footprint topology and market dynamics with the infrastructure and dynamics of the natural gas infrastructure adds another level of sophistication to modeling. To continue to assure a high level of reliability in the changing business environment, it is the required approach for the foreseeable future. MISO and its Stakeholders are embracing the challenge through increased collaboration with the natural gas industry and with each other.

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