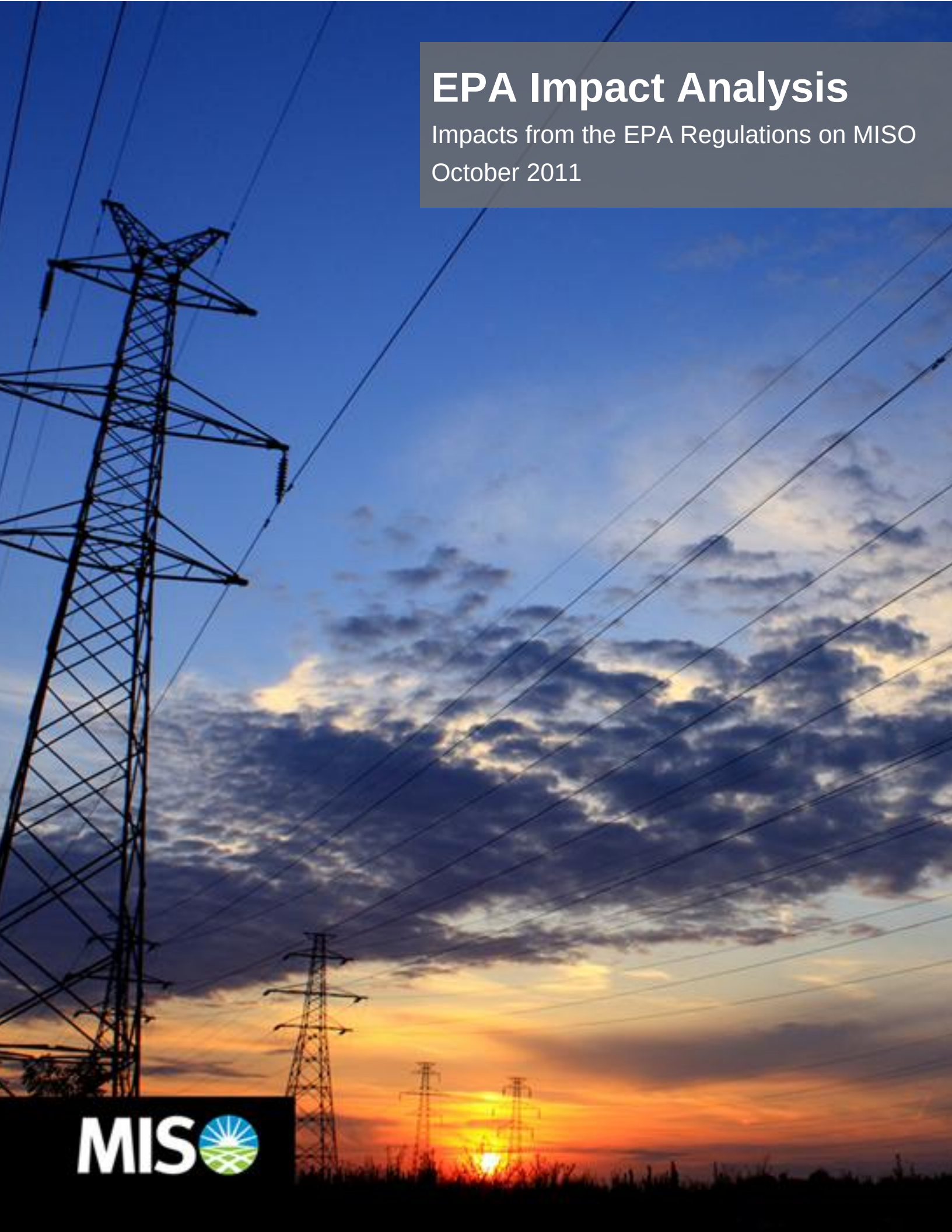
EPA Impact Analysis

Impacts from the EPA Regulations on MISO

October 2011



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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.

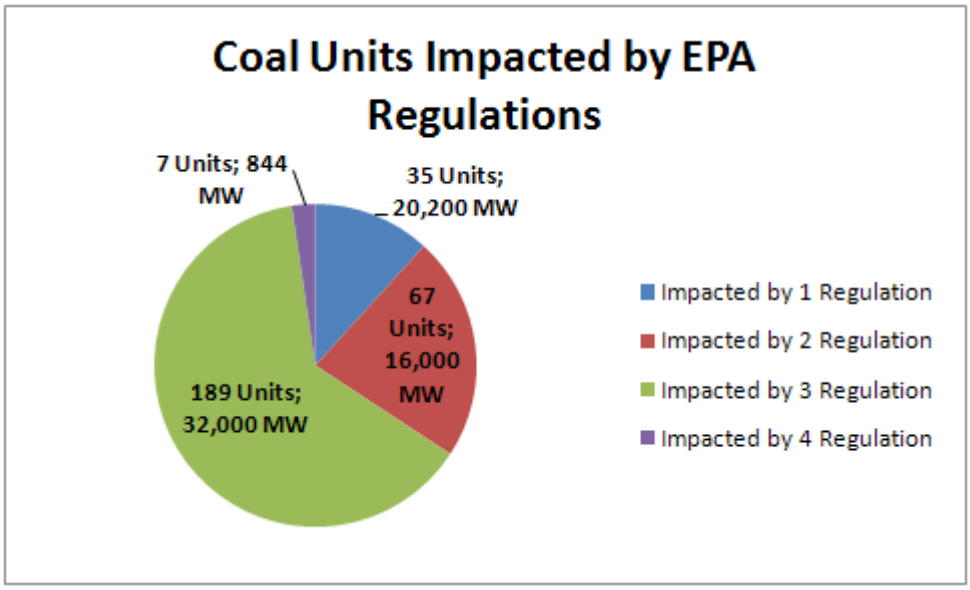

Figure 2.1-1: Number of units affected by EPA regulations

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.

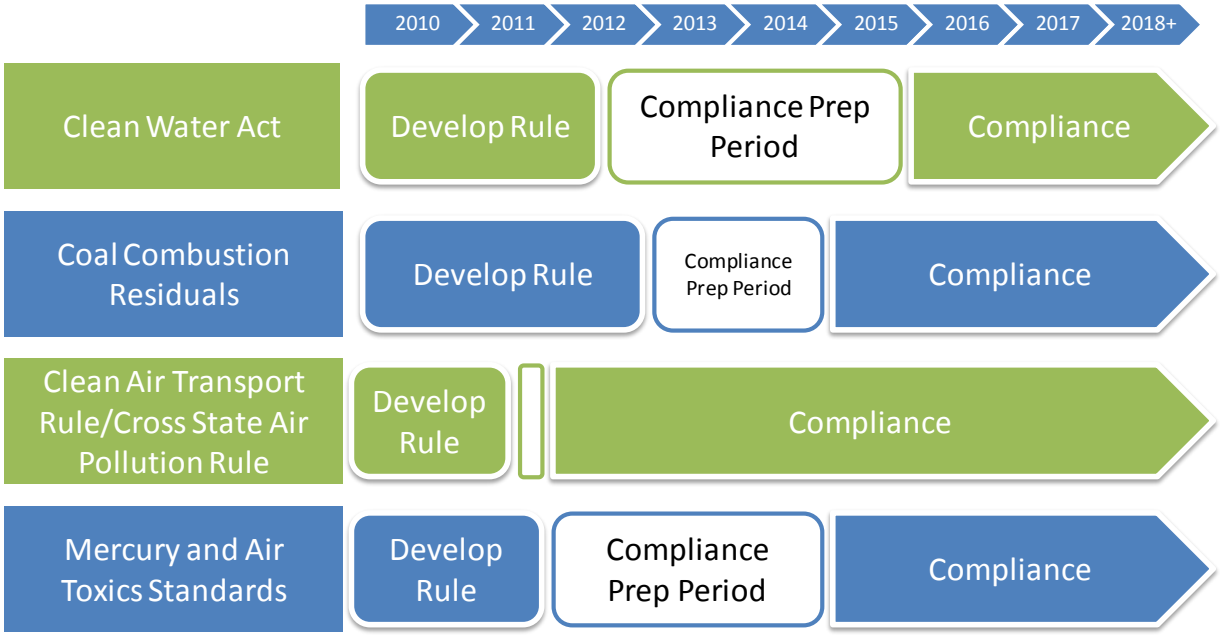

Figure 2.1-2: Estimated timeline for regulation development and implementation

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.

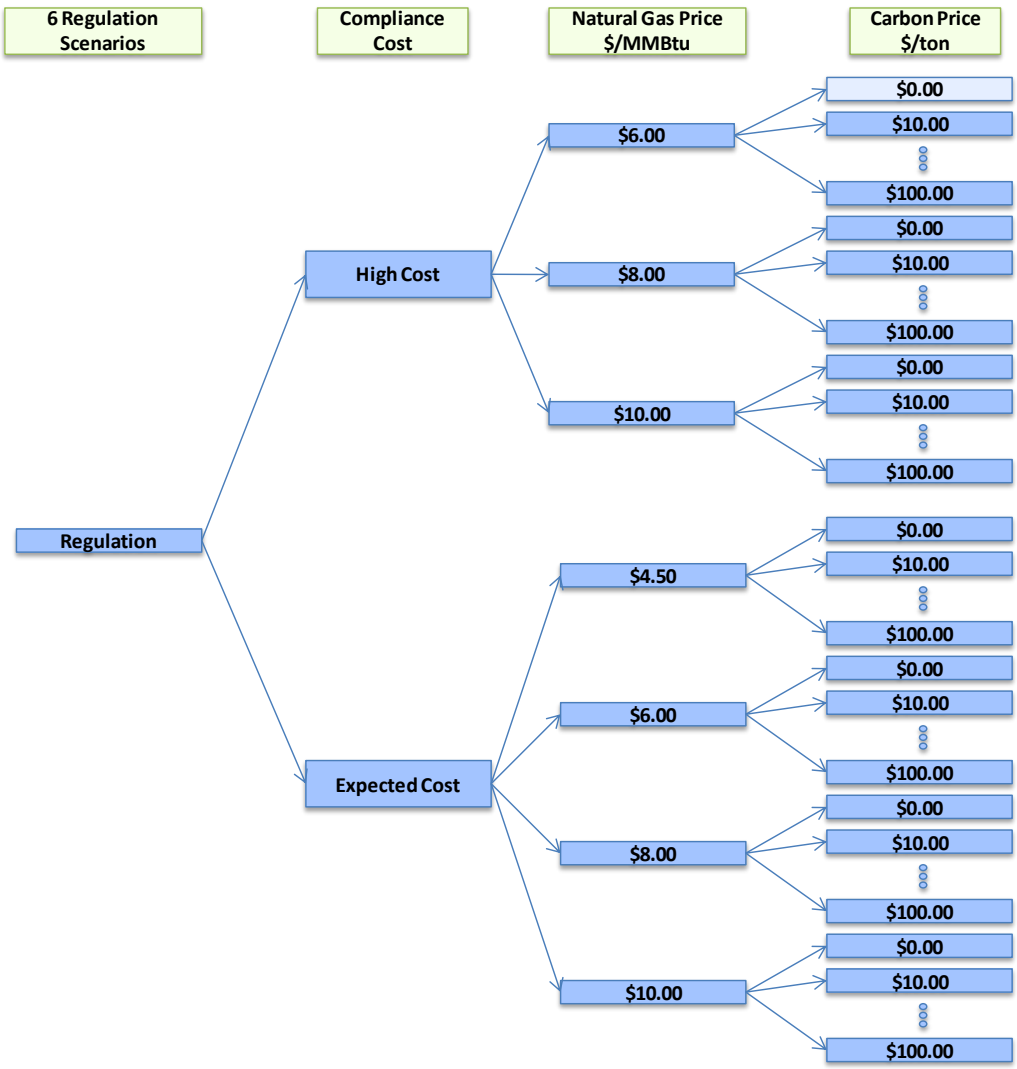

Figure 2.2-1: Decision tree of EPA cases

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.

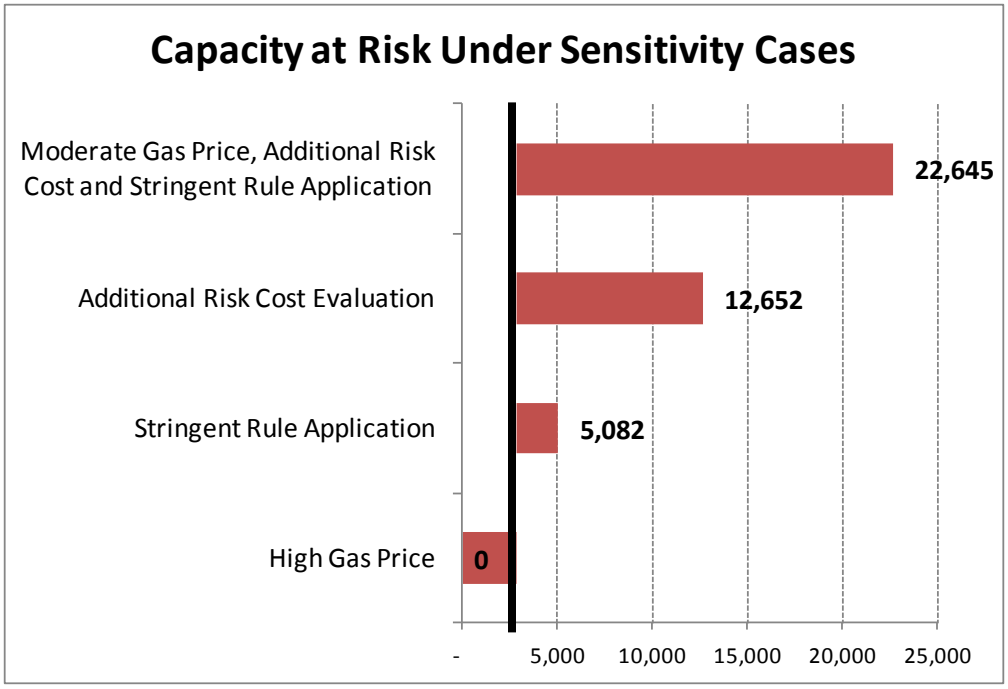

Figure 2.2-2: Tornado chart demonstrating the impacts of sensitivities on potential capacity retirements

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.

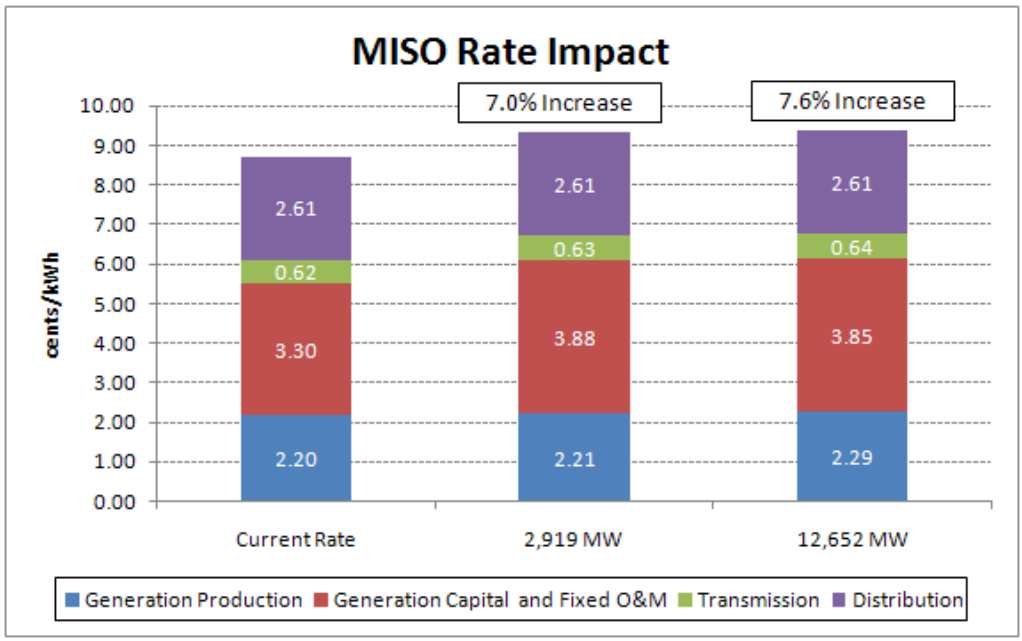

Figure 2.4-1: MISO rate impact excluding the cost of carbon in the production costs

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.

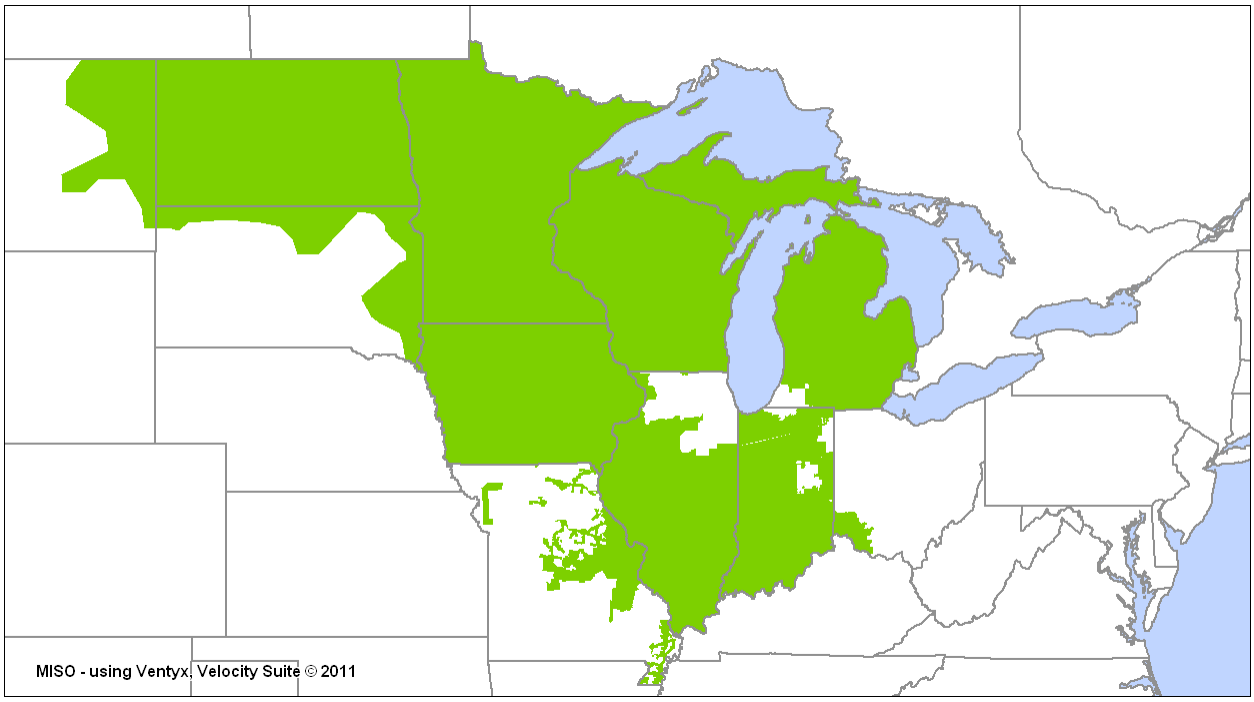

Figure 3-1: MISO market footprint

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.

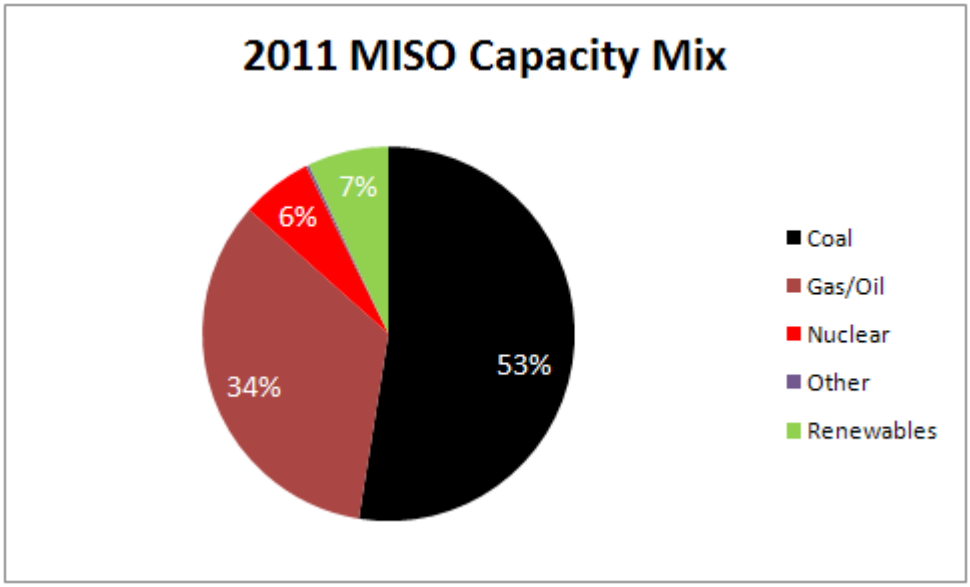

Figure 3.1-1: MISO capacity mix

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.

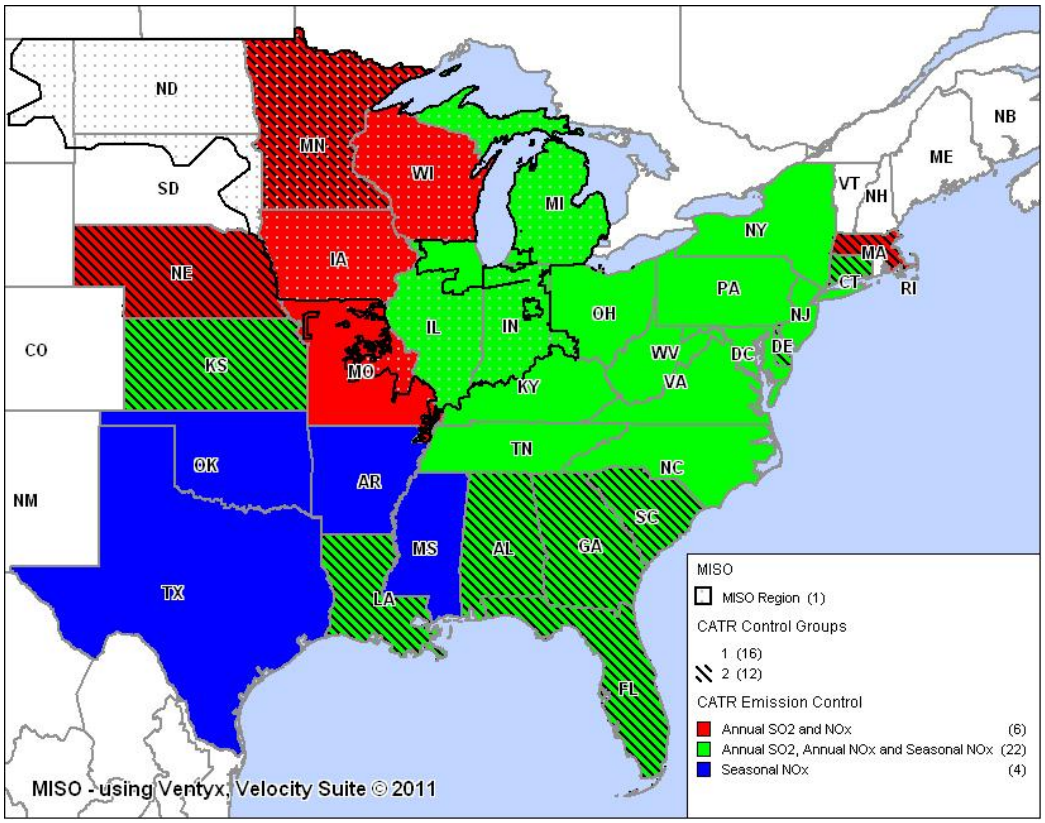

Figure 4.3-1: Proposed Clean Air Transport Rule implementation

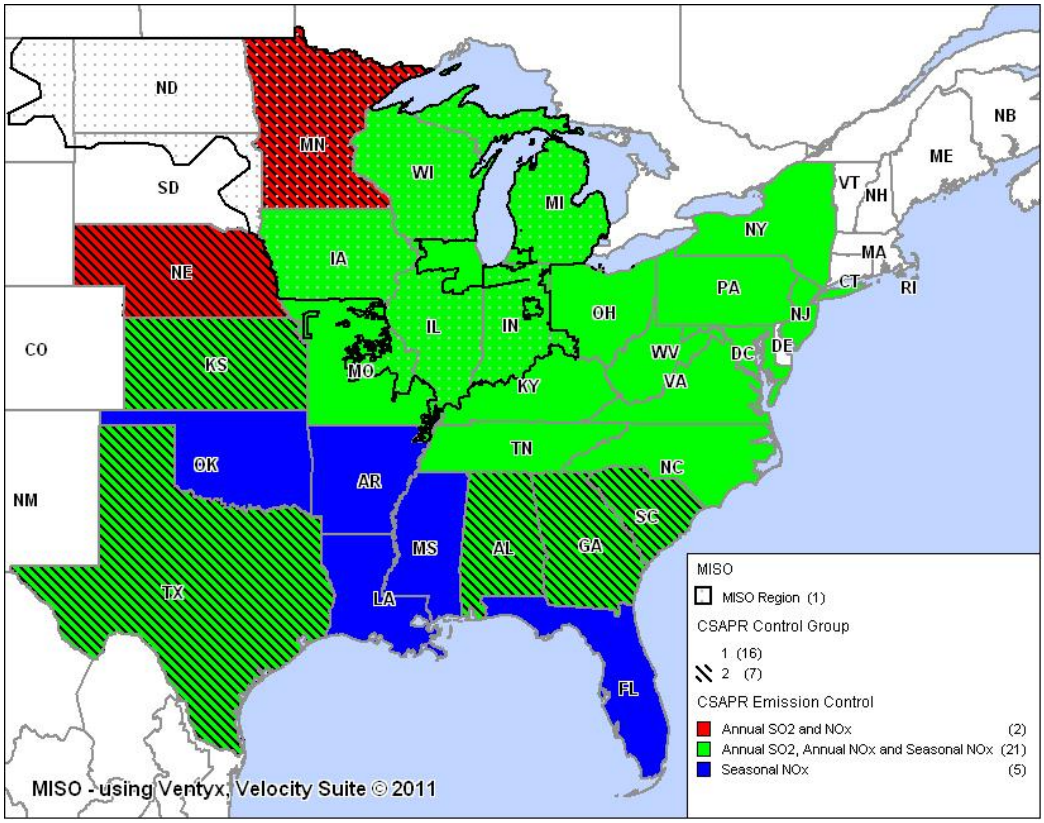

Figure 4.3-2: Final Cross State Air Pollution Rule implementation

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.

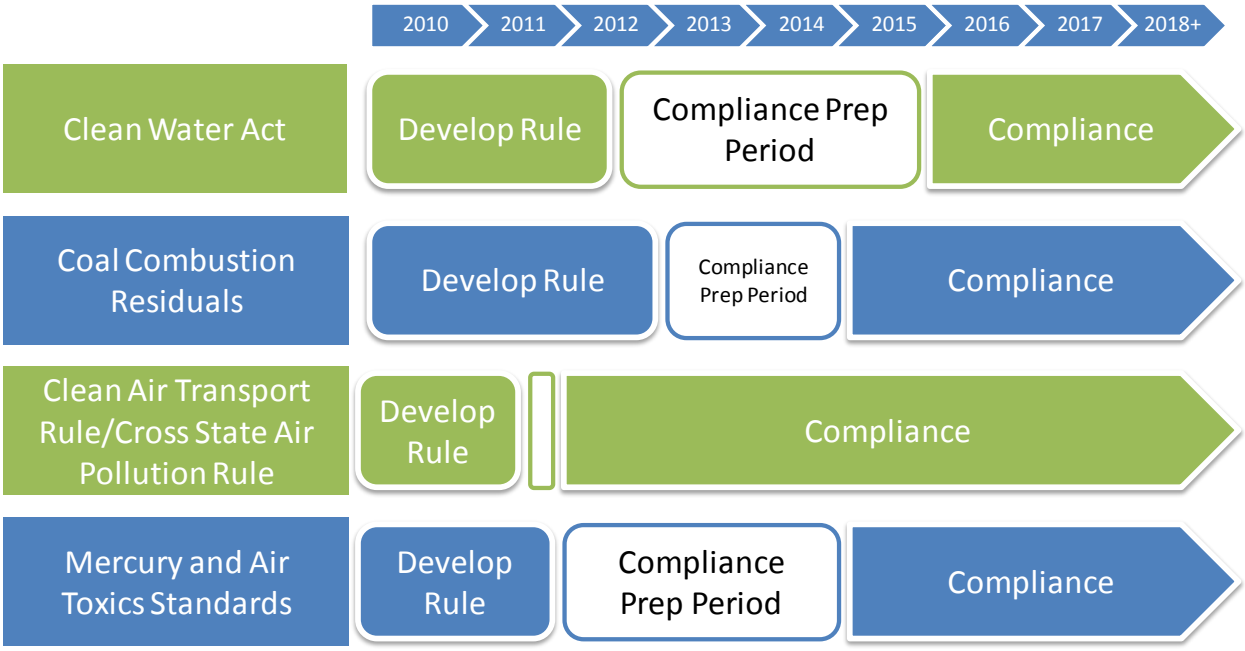

Figure 4.5-1: Estimated timeline for regulation development and implementation

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.

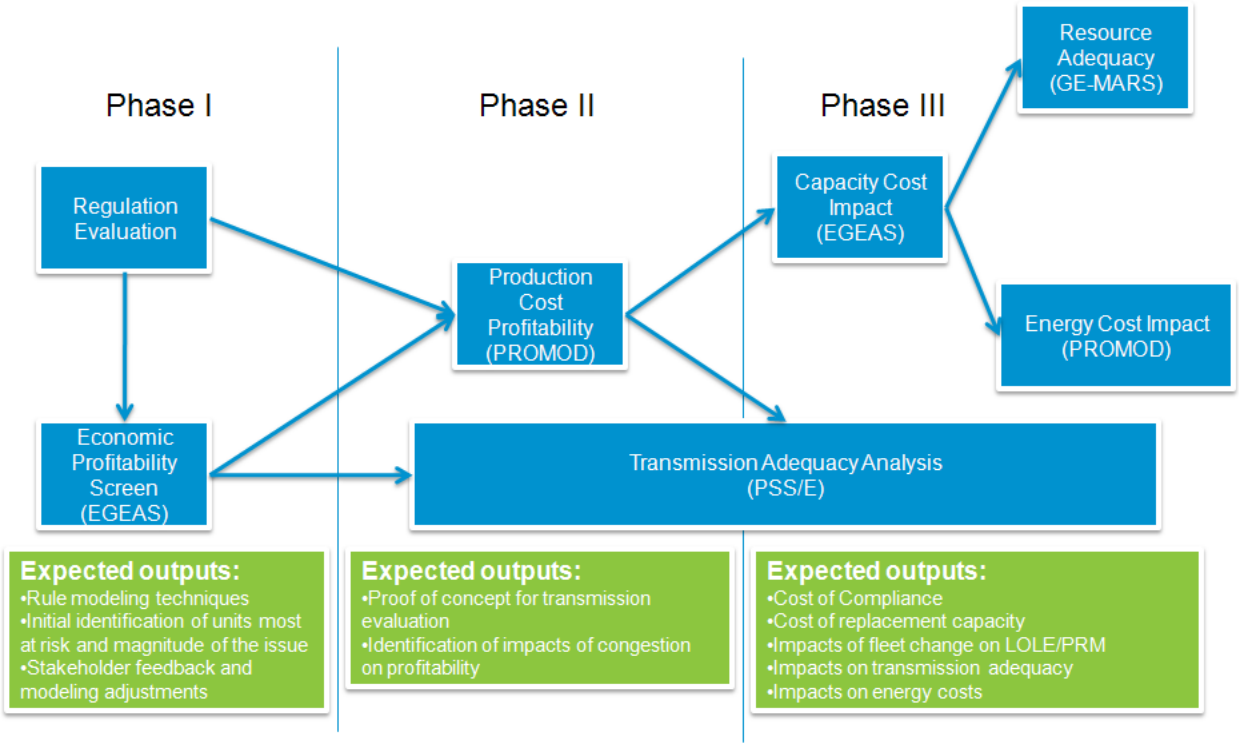

Figure 6-1: Flow diagram of EPA Impact Analysis

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.

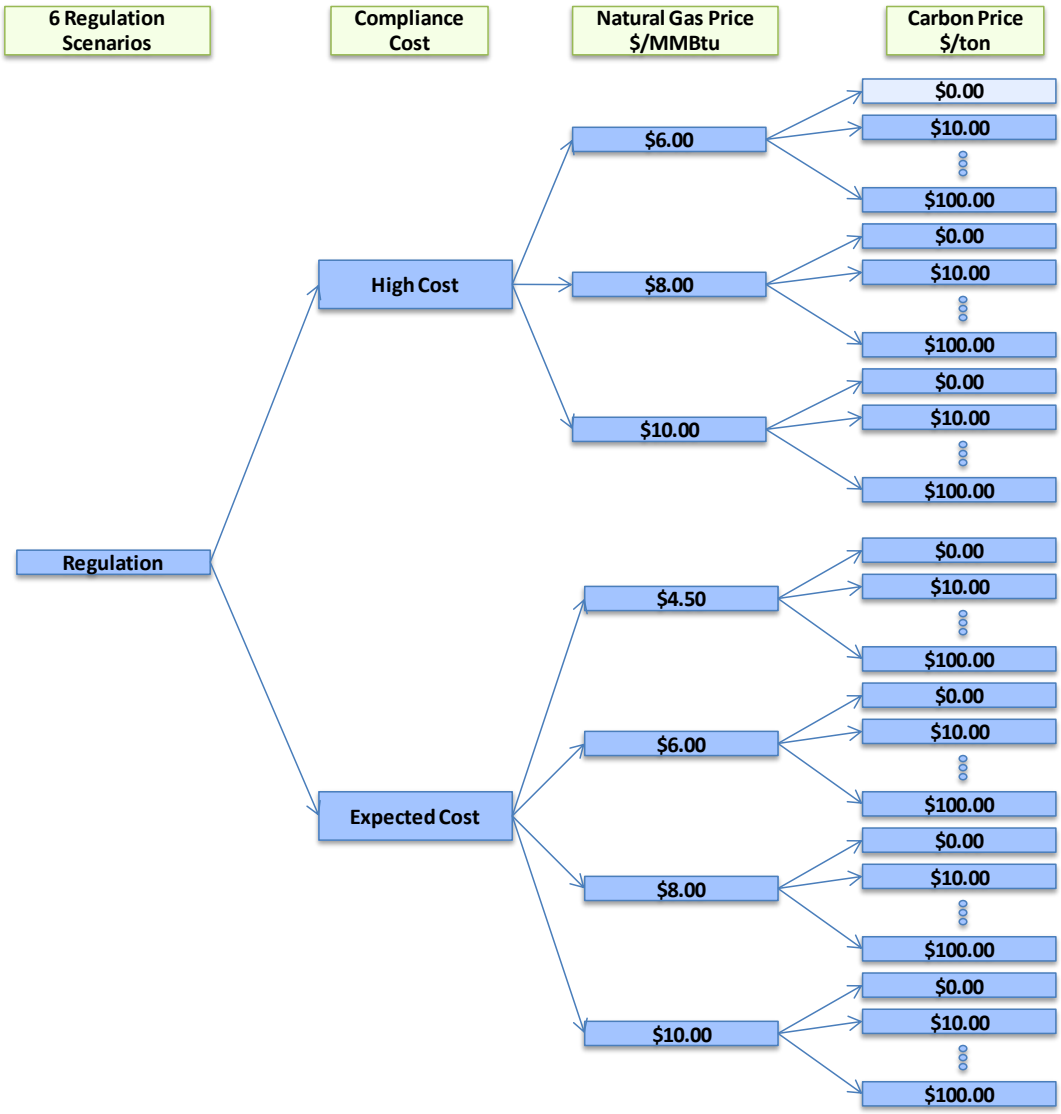

Figure 7.1-1: Decision tree of EPA Cases (total of 77 sensitivities per regulation evaluated)

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.

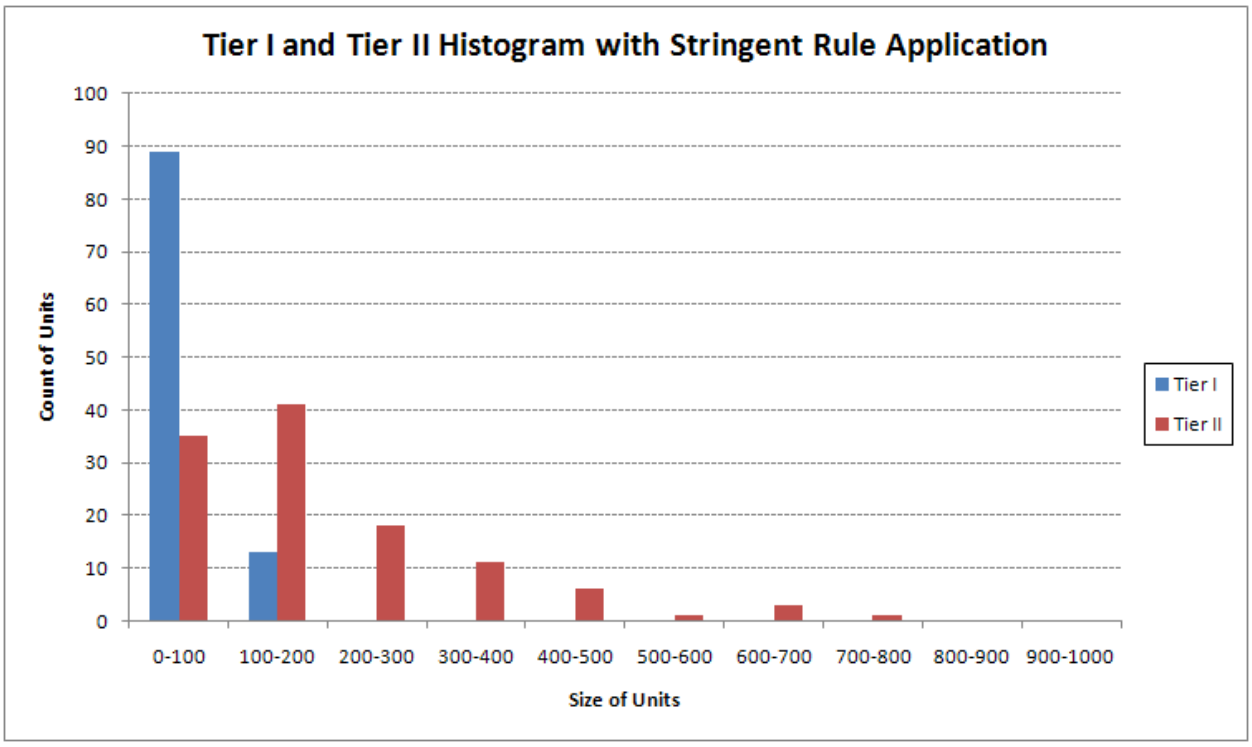

Figure 7.2-1: Tier I and Tier II histogram stringent rule application

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.

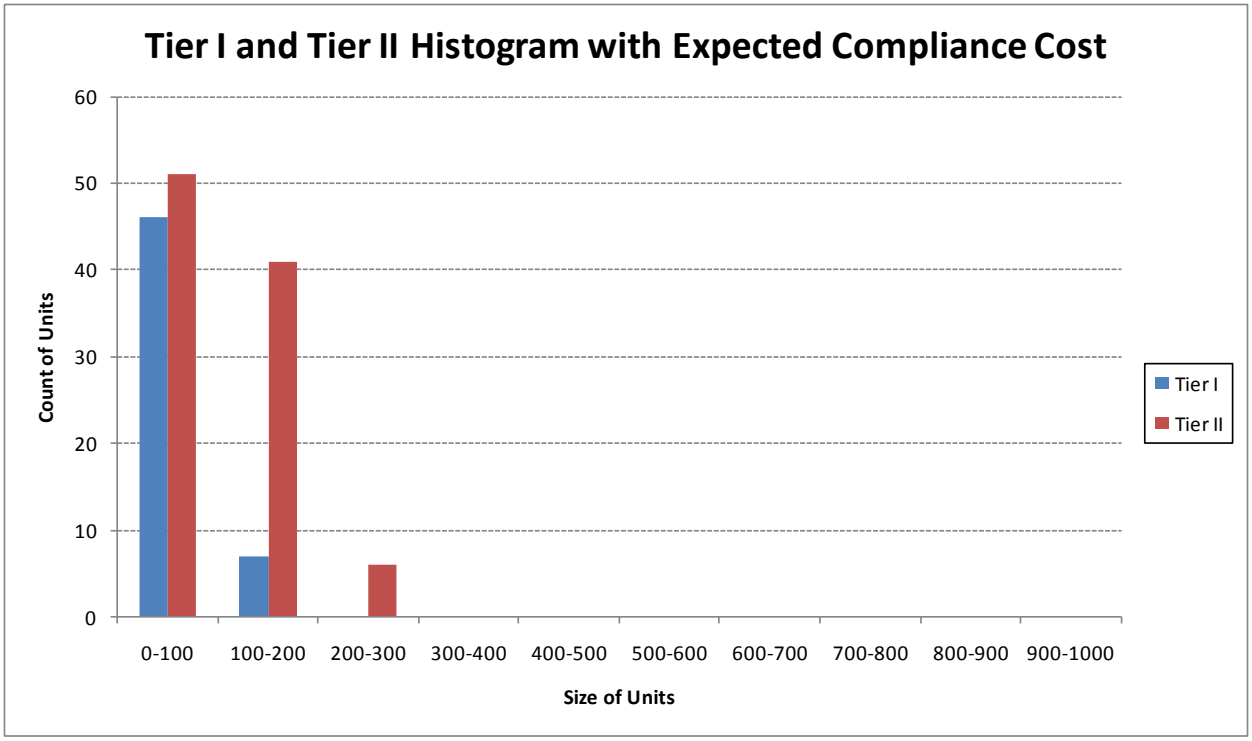

Figure 7.2-2: Tier I and Tier II Histogram for expected compliance cost application

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.

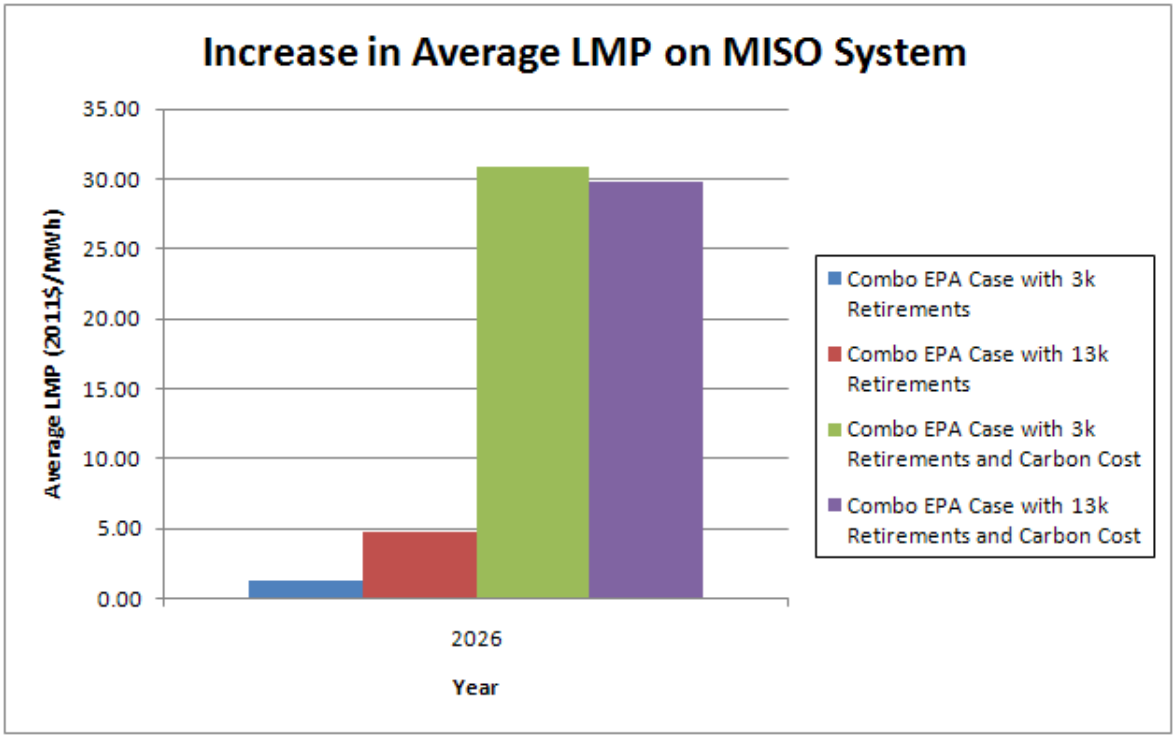

Figure 9.2-2: MISO average LMP impact

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.