MISO's Phase III Analysis of the Draft CPP

Final Report

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Contents

Study Disclaimer

The results presented in the following pages are based on the **draft** Clean Power Plan as released on June 2, 2014. Results are indicative and are intended to inform MISO stakeholders in the formulation of compliance plans.

1 Executive Summary

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) proposed a rule to reduce carbon dioxide (CO_2) emissions from existing fossil-fired generation units. The draft rule, also known as the Clean Power Plan (CPP), included state-by-state, CO_2 emissions targets based upon a set of "building blocks".

MISO's analysis of the draft CPP encompassed three phases, each designed to provide specific insights into the potential impacts of the rule. The two overarching goals of these analyses were:

- To inform stakeholders as they formulate compliance plans
- To establish a framework for analysis of the final rule

The first two phases[1] of MISO's study focused on the potential costs of generation capital investment and energy production under compliance with the proposed rule. Numerous CO_2 reduction strategies were evaluated including implementation of the EPA's building blocks on a regional (MISO-wide) basis, as well as the application of alternative compliance strategies at the regional and sub-regional (MISO Local Resource Zone) levels.

Study design for Phase III was informed by the results of these initial analyses, as well as stakeholder requests for state-level modeling, inclusion of electric transmission and consideration of gas infrastructure. Phase III quantified potential power system ramifications of the CPP, such as increased cost for energy production, and impacts to generation dispatch and transmission system utilization. Potential reliability impacts were identified, along with transmission congestion trends. The study also served as a first step in developing transmission solutions to facilitate reliable and cost-effective implementation of the changes required for compliance with the CPP.

The analysis tested five compliance scenarios and a reference scenario (Figure 1) to understand the impacts of how the MISO region may comply with the emissions limitations.

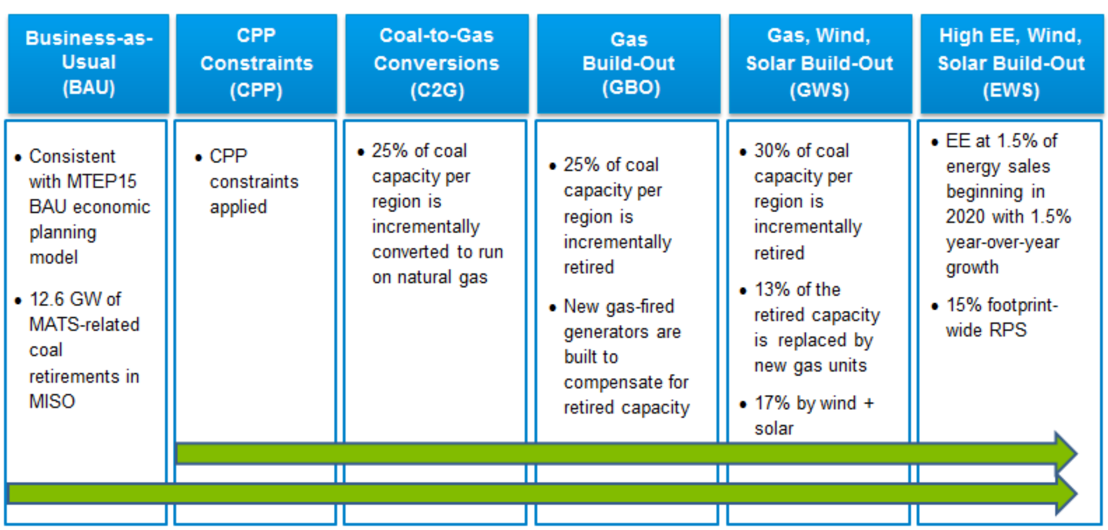


Figure 1 Phase III Scenarios

[1] Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units.

The five compliance scenarios were modeled for three years (2020, 2025 and 2030) and three types of compliance areas (state-by-state, sub-regional and regional). Both economic and reliability analysis were performed, using PLEXOS and PSS/E models, respectively. Additionally, preliminary evaluation of rate versus mass emissions constraints was performed to understand these different options for compliance.

High-level takeaways based on study results include:

- Regional compliance produces \$4B to \$11B in 20-year net present value production cost savings versus state approaches, while sub-regional compliance respectively produces \$2.5B to \$11.5B in savings. These figured do not include the cost of CO_2 allowances.
- Regardless of siting assumptions, electric and gas infrastructure costs for interconnection of new or converted gas units are comparable.
- CPP constraints significantly increase congestion regardless of compliance approach, and transmission congestion is higher under a state approach than a regional approach.
- Multi-billion dollar transmission build-out would be necessary for compliance in the scenarios studied, driven by the level of retirements and the location and type of replacement capacity.
- Transmission expansion would be needed to mitigate reliability impacts of compliance, largely driven by coal retirements.
- Generation dispatch would change dramatically from current practices, requiring additional study to fully understand the ramifications.

While the results offer valuable insights into how the energy landscape may change under compliance, the process of draft rule analysis also yielded valuable lessons that will shape MISO's study of the final rule. In particular, it highlighted the value of a phased approach to analysis, which produced useful information prior to completion of the entire study. Additional lessons learned on study process and design include:

- Stakeholder feedback throughout was essential to producing relevant outputs.
- The PLEXOS model was a good fit for analysis of the CPP, allowing for explicit modeling of constraints on CO_2 emissions, as well as state-by-state compliance.
- Studying one or two compliance actions (e.g. coal retirements, renewables build-out, re-dispatch) at a time allowed for developing a better understanding of the impacts of pulling these individual compliance levers.

The draft rule analysis was a significant undertaking, based on a complex and sometimes ambiguous regulation. Though the study of the final rule will necessitate similar efforts of rule interpretation and technical analysis, MISO is well-positioned to address these challenges. Over the course of the next year, MISO will continue to work closely with stakeholders, state regulators and neighboring ISOs to understand how this regulation will change the energy landscape and to plan for its implementation.

2 Introduction

The U.S. Environmental Protection Agency (EPA) proposed a rule on June 2, 2014, designed to reduce carbon dioxide (CO_2) emissions from existing fossil-fired generation units. MISO developed a three-phase study to analyze the impacts of the draft rule and provided comments to the EPA based on their analysis, which indicated reliability risks, loss of value from states choosing separate solutions and risks from differing rate and mass compliance approaches. Through these comments and others provided, the EPA revised its final rule (issued on August 3, 2015) to mitigate many of the risks MISO identified in the draft rule analysis. MISO's three-phase study approach also increased understanding of many of the potential impacts of the final rule and acted as a dry run for how the final rule would be analyzed along with providing information to impacted stakeholders to help formulate cost-effective compliance approaches.

MISO's Phase I and II[2] analysis focused on the potential compliance costs associated with the proposed rule. CO_2 reduction strategies reviewed were:

- Applying the EPA's building blocks on a region-wide (MISO-wide) basis. This strategy costs approximately $90 billion in net present value over the 20-year study period, which equates to approximately $60/ton of CO_2 emissions avoided from existing fossil-fired units.
- Applying alternative compliance strategies outside of the building blocks (for example, retiring and replacing coal units with combined-cycle gas capacity). This strategy costs $55 billion in net present value for a regional approach, which equates to approximately $38/ton of CO_2 emissions avoided from existing fossil-fired units.
- Applying a similar outside-the-blocks strategy at a sub-regional level (using the MISO Local Resource Zones). This strategy indicates a cost of $83 billion in net present value, which equates to an approximate average of $57/ton of CO_2 emissions avoided from existing fossil-fired units.

The annual cost avoidance of a regional carbon constraint approach compared to a sub-regional approach is approximately $3 billion. MISO finds that the EPA's proposal could put up to 14 GW of additional coal capacity at risk of retirement in order to achieve lower compliance costs with the CO_2 reductions. This analysis focuses on generation capital investment and production costs. Costs of additional electric transmission system or gas pipeline infrastructure required to implement the CO_2 reduction strategy are not included. Phase III of this study considers transmission and pipeline costs.

MISO's review also indicates that the interim targets in the proposed rule will require significant CO_2 reductions (the magnitude of early reductions required to meet the averaging) in the 2020 timeframe. This study indicates that this short timeline may not allow cost-effective, long-term planning. If coal plant retirements are part of the compliance strategy for 2020, corresponding capacity additions (for reliability and resource adequacy) in a two-year window would be extremely difficult. MISO's experience is that new gas plant construction typically requires three to six years. If new transmission and gas pipeline additions are needed to accommodate the capacity expansion, this timeline may be even longer. This finding suggests that in order to meet the 10-year average identified in the proposed rule, it is likely that entities will need to take immediate action. Since it is possible that state plans will not be finalized until the 2018-19 timeframe, there will be little time for decisions and implementation for infrastructure changes before 2020. Phase III is the last draft rule analysis phase. It focused on questions left unanswered by Phases I and II. The assumptions, results and lessons learned are laid out in the following sections.

[2] Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units.

3 Study Findings

This section addresses the results of the Phase III study including comprehensive compliance costs, generation changes, reliability and economic transmission impacts.

3.1 Compliance Costs

Total compliance costs[3] for each scenario of the CPP Phase III study were calculated by summing the production costs (variable operating and maintenance, fuel), resource capital costs, transmission portfolio capital costs (maintenance, carrying) and pipeline lateral capital costs. Costs are based on a 20-year Net Present Value (NPV) calculation using a 2.5% discount rate. Production costs for 2015 to 2019 were calculated from the BAU case for all scenarios. For 2020, 2025, and 2030, production costs were developed from the results of the PLEXOS simulations; interim year costs were interpolated from these same results.

State costs and regional costs are presented in Table 1, separated by a "/". Resource capital costs were calculated from values in MTEP15 and MTEP16, separated by a "|". Production cost savings from state to regional and sub-regional costs follow in Figure 2.

Total compliance costs, limited to the four areas examined during Phase III, ranged from $46 - 106B. The individual components are discussed in the following sections.

Cost for State / Regional Compliance Approaches (20-yr NPV in $B) Incremental Resource Capital Costs for MTEP15 | MTEP16 (difference from BAU)					
	CPP	C2G	GBO	GWS	EWS
Production Costs	64 / 53	48 / 40	54 / 45	26 / 21	-27 / -31
Resource Capital Costs		13 | 4	9 | 9	51 | 39	131 | 105
Transmission Portfolio Capital Costs*	2.6 / 1.8	2 / 1.5	2.2 / 1.7	3.3 / 2.4	1.7 / 1.4
Pipeline Lateral Capital Costs**		1.3	0.5	0.1	
Total System Compliance Cost Range	55 - 67	46 - 65	56 - 66	62 - 80	75 - 106

**Reliability upgrades excluded*
***Mainline costs excluded*

Table 1 Compliance Costs for State / Regional Approaches

[3] Other costs that may be incurred for compliance are outside the scope of this study.

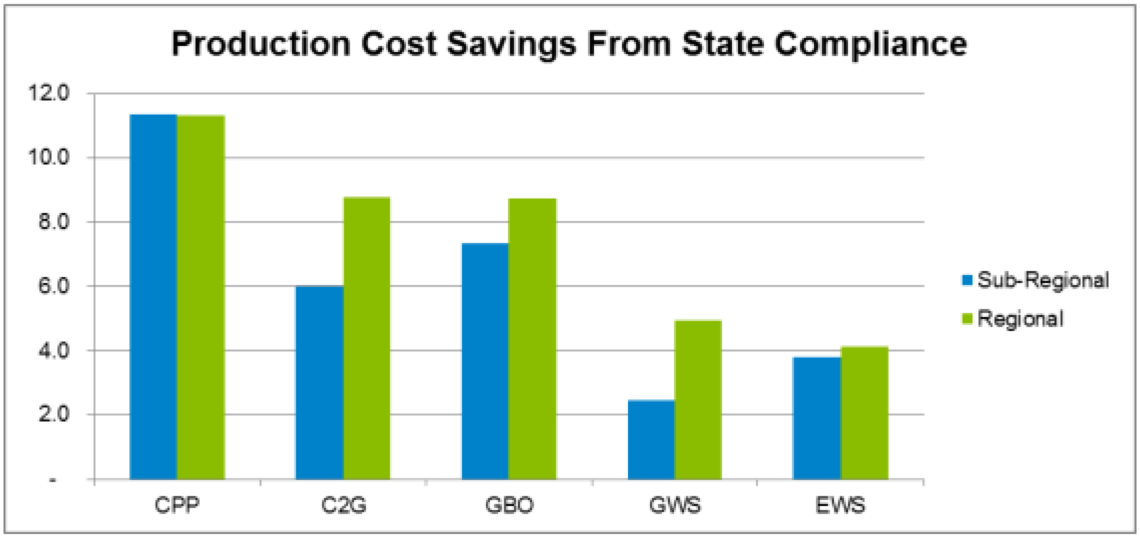


Figure 2 Production Cost Savings from State Compliance

In all cases, sub-regional costs fell between state and regional, although sub-regional costs track more closely with regional costs.

3.1.1 Transmission Expansion Costs

Costs for transmission infrastructure are shown again in the Table 2.

	CPP	C2G	GBO	GWS	EWS
Transmission Portfolio Capital Costs ($B)*	2.6 / 1.8	2 / 1.5	2.2 / 1.7	3.3 / 2.4	1.7 / 1.4

Table 2 Transmission Portfolio Capital Costs

Transmission costs range from $1.4 – 3.3B based on 10 portfolios developed from 34 individual projects. Portfolios represent the lower end of transmission investment for congestion relief under the CPP. A detailed explanation regarding the development process and make-up of portfolios follows in Section 3.4.

3.1.2 Gas Pipeline Lateral Costs

As a proxy for gas infrastructure expansion costs under CPP compliance, gas lateral costs were calculated for new or converted gas-fired units per scenario in Phase III. Individual lateral costs were determined based on the size (capacity, MW) of the interconnected generator, the year of installation and the proximity to the nearest appropriately-sized pipeline.

The $/inch-mile figure used to estimate lateral costs was sourced from a 2012 Penn Energy Research study, as cited in the 2014 EISPC Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection[4]. This figure, $155,000/inch-mile, is an average across the US and is given in 2012 dollars. For the purposes of the Phase III cost calculations, 2012 dollars were escalated by 2.5% per year to the year of installation.

[4] See http://www.naruc.org/Grants/Documents/ICF-EISPC-Gas-Electric-Infrastructure-FINAL%202014-12-08.pdf.

The assumptions for pipeline diameter-to-generator size (capacity, MW), as follows, were based on industry figures and internal MISO expertise:

- Generators with a max capacity of 300 MW or less = 12" diameter lateral
- More than 300 MW but less than 500 MW = 16" diameter lateral
- 500 MW or greater = 20" diameter lateral

Proximity of each individual gas-fired generator to the nearest appropriately-sized gas pipeline was determined using MapInfo[5]. Per-unit costs were then determined by applying the following formula:

[escalated $/inch-mile figure] x [lateral diameter (in)] x [proximity to pipeline (miles)]

Per unit costs were then summed per scenario (Table 3).

	CPP	C2G	GBO	GWS	EWS
Pipeline Lateral Capital Costs ($B)	**-**	**1.3**	**0.5**	**0.1**	**-**

Table 3 Pipeline Lateral Capital Costs

Mainline pipeline costs were not considered in this round of analysis but will be considered in the study of the final rule.

3.1.3 Resource Expansion Costs

Resource expansion costs were calculated based on the number of units installed and the year of their installation for each compliance scenario. A range of costs for each resource are given based on MTEP15 and MTEP16 values, detailed in Sections 8.17 and 8.18. The costs associated with implementation of energy efficiency in the EWS scenario were calculated from the figures issued by the EPA in their supporting documents for the draft rule. The costs are significantly higher in the GWS and EWS scenarios because of the high amount of added renewables. Costs for the C2G and GBO are comparable with one another because similar amounts of gas capacity are built in these scenarios.

Note that Phase III did not optimize resource expansion for each scenario, but rather used the results of Phase II to inform scenario development. Additionally, resource expansion was not performed with consideration for a Planning Reserve Margin on the state level, thus cost differences may be undervalued. Optimizing resource expansion, and subsequently calculating resource capital costs, was not the intent of Phase III; however, the costs have been included here to provide a more comprehensive indication of the cost of CPP compliance.

[5] See http://www.pitneybowes.com/us/location-intelligence/geographic-information-systems/mapinfo-pro.html.

	CPP	C2G	GBO	GWS	EWS
Resource capital costs	0	13 | 4	9 | 9	51 | 39	131 | 105

Table 4 Resource Capital Costs

3.1.4 Marginal Cost of Compliance (Implied CO_2 prices)

Phase III used rate constraints on CO_2 emissions as the method to enforce compliance with the CPP. When a physical constraint is used, PLEXOS calculates a shadow price for that constraint. The shadow price for the emission rate constraint is the marginal cost of CO_2 emissions.

As an alternative, a CO_2 price could be used as an input. The shadow price indicates the input CO_2 price needed to achieve the same dispatch result as when a rate constraint is applied.

Figure 3 shows the price range over the three study years and five scenarios for all MISO states (the bars indicate minimum, average and maximum prices). A zero price indicates the state would have been compliant even without a change in dispatch. A higher price indicates the state has a more difficult time complying.

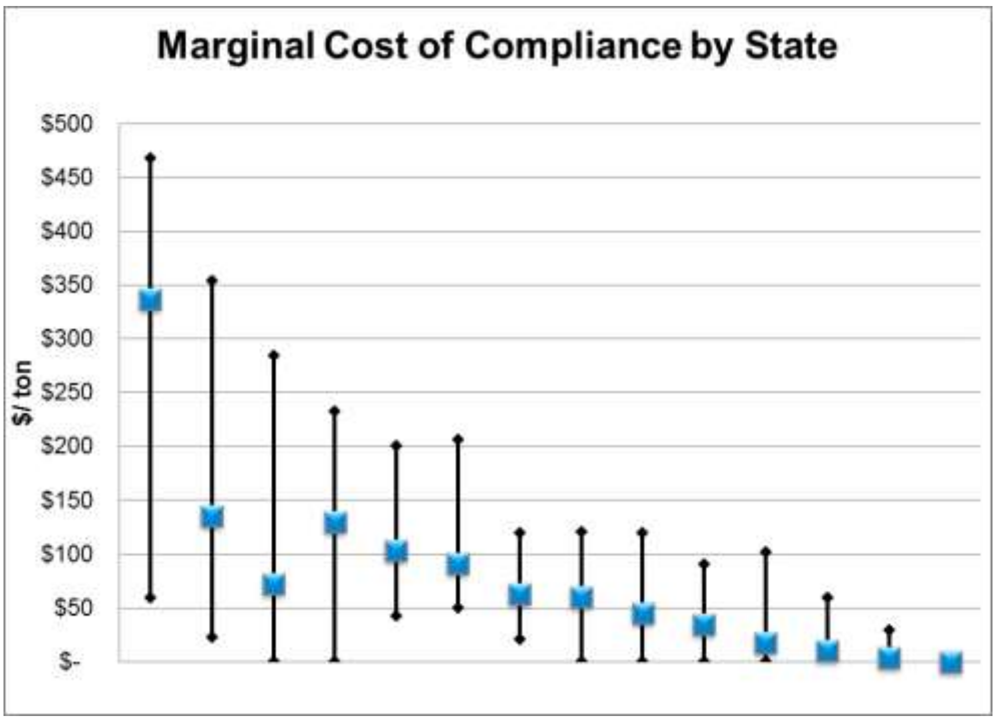


Figure 3 Marginal Cost of Compliance by State

The CO_2 shadow price was also considered in analyzing results from the sub-regional scenarios. Figure 4 details the range of shadow prices for MISO North, MISO South and MISO Central and compares them to the average[6] shadow price of the entire MISO region.

[6] Average is calculated across all years and scenarios of regional runs.

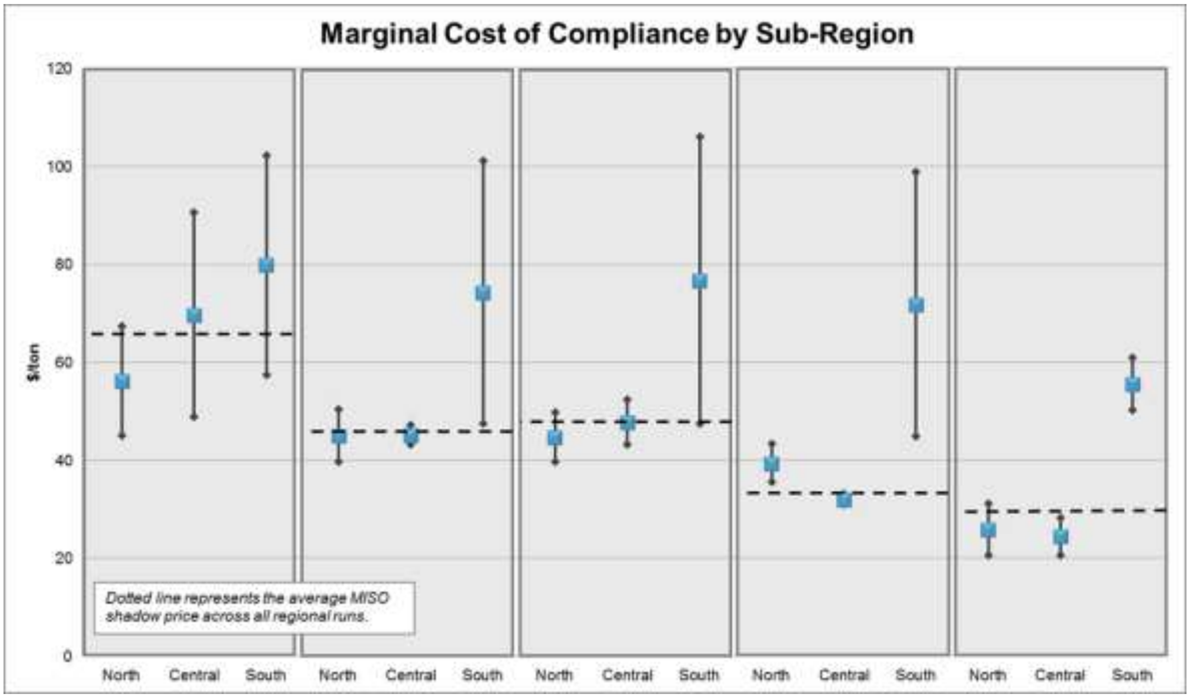


Figure 4 Marginal Cost of Compliance by Sub-Region

There is significant variation among the three sub-regions in the CPP scenario. In all other scenarios, the North and Central sub-regional prices converge, while the South sub-region experiences higher shadow prices in the latter years of the study.

3.1.5 Locational Marginal Prices (LMPs)

LMPs in MISO vary dramatically across scenarios, depending on the capacity additions made for compliance. Hub prices range from an annual average of $28.4/MWh to $114.7/MWh between the various scenarios and years. The case with the highest LMPs is the CPP scenario under state-level compliance and the lowest is the EWS scenario under regional compliance. The CPP scenario has the most difficult time complying since it relies solely on re-dispatch and must run more expensive units. The EWS scenario experiences low prices because of its high level of energy efficiency and the build out of renewable generation, which has a very low marginal cost.

Detailed LMPs for each MISO hub for all years and scenarios can be found in Section 11.

3.2 Generation Impacts

3.2.1 Changes in Dispatch

Figure 5 shows energy production by fuel type for all scenarios in the year 2030 and illustrates the following:

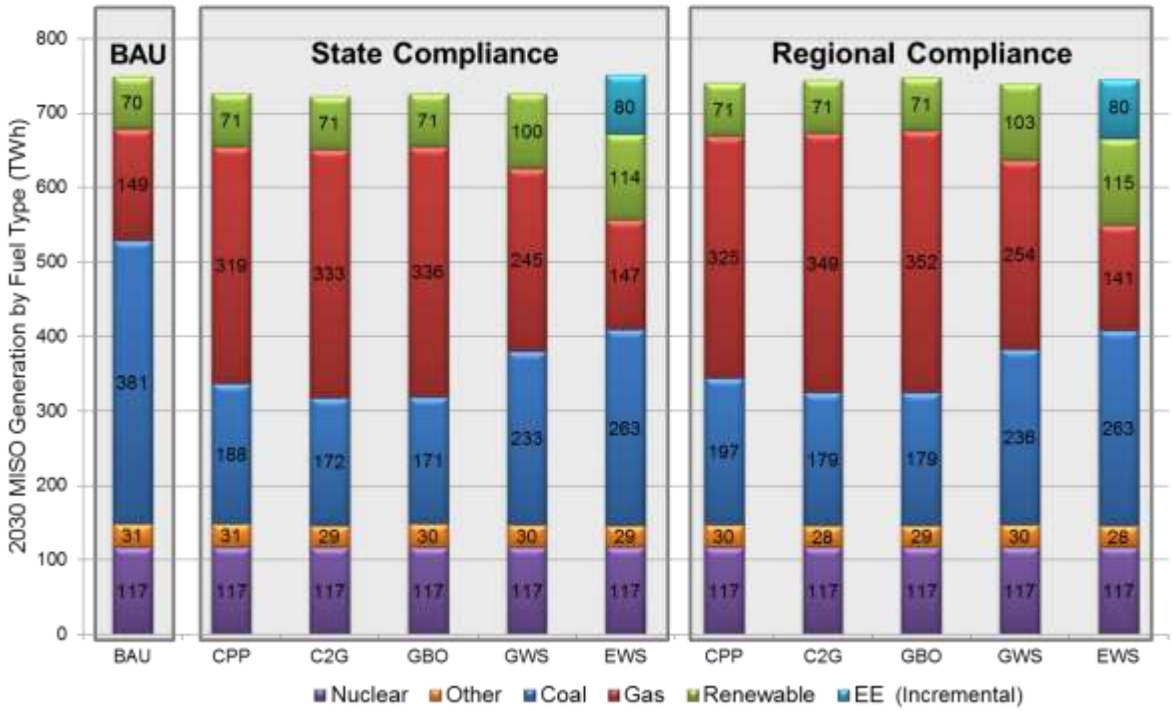


Figure 5 2030 MISO Generation by Fuel Type

- Enforcing CPP constraints significantly reduces coal generation (energy) regardless of whether coal units are being retired (CPP vs. C2G and GBO).
- Retiring some coal units allows those left online to run more than in a compliance scenario with no retirements. Recall that in the C2G and GBO scenarios, the coal capacity is reduced by 25% but the generation is only reduced by 8% from the CPP case. Thus, remaining coal units have higher capacity factors.
- More renewables allow more coal generation and these renewables offset gas generation as seen in the GWS and EWS scenarios. This is due mainly to the fact that renewables are counted twice for credit under the draft CPP, i.e. are counted toward MWh in the denominator and also displace emissions-producing generation in the denominator.
- Increasing energy efficiency (EE) displaces gas generation since gas is the marginal unit, and EE allows for increased CO_2 production since it is also counted twice for credit in the rate formula.
- Total generation by fuel type is very similar in both state and regional compliance. However, further analysis reveals that specific generating units differ greatly between state and regional compliance. Since more expensive units are running for compliance reasons, the cost to the system is higher under state compliance.
- Interchange (imports/exports) and energy storage account for the changing amount of total generation in MISO. All states and regions maintain compliance, but energy transfer continues to be optimally scheduled.

Figure 6 demonstrates an example of how generation changes in the 2030 CPP scenario when moving from state compliance to regional compliance. Purple indicates economic generation that cannot be dispatched under state-level compliance; green indicates generation dispatched under state-level but not regional compliance.

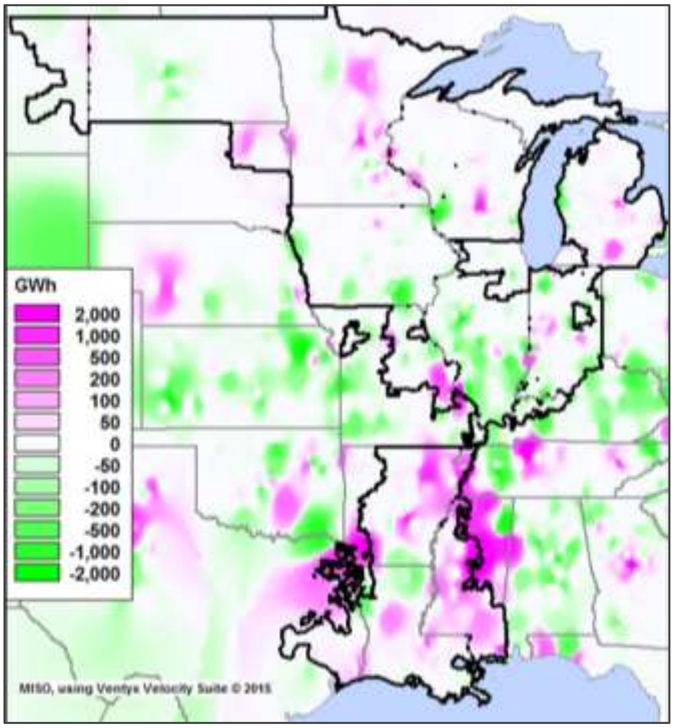


Figure 6 2030 Regional vs. State Generation

From the map, the follow observations can be made with regard to state versus regional compliance:

- States that can easily meet their rate targets can help states experiencing more difficulty meeting their rate targets, allowing more coal generation to stay online.
- States that had to switch from coal to gas for state-level compliance can again produce more from coal in the regional compliance scenario. States that did not experience as much switching for state-level compliance can back down inefficient coal under regional compliance.

3.2.2 Coal & Gas Unit Performance

In light of the resource mix changes discussed in Section 3.2.1, MISO considered the performance of coal and gas units in comparison to historical dispatch. First, capacity factors were examined for MISO coal units under the six scenarios for 2030. Figure 7 shows the capacity factor of each coal unit for all scenarios.

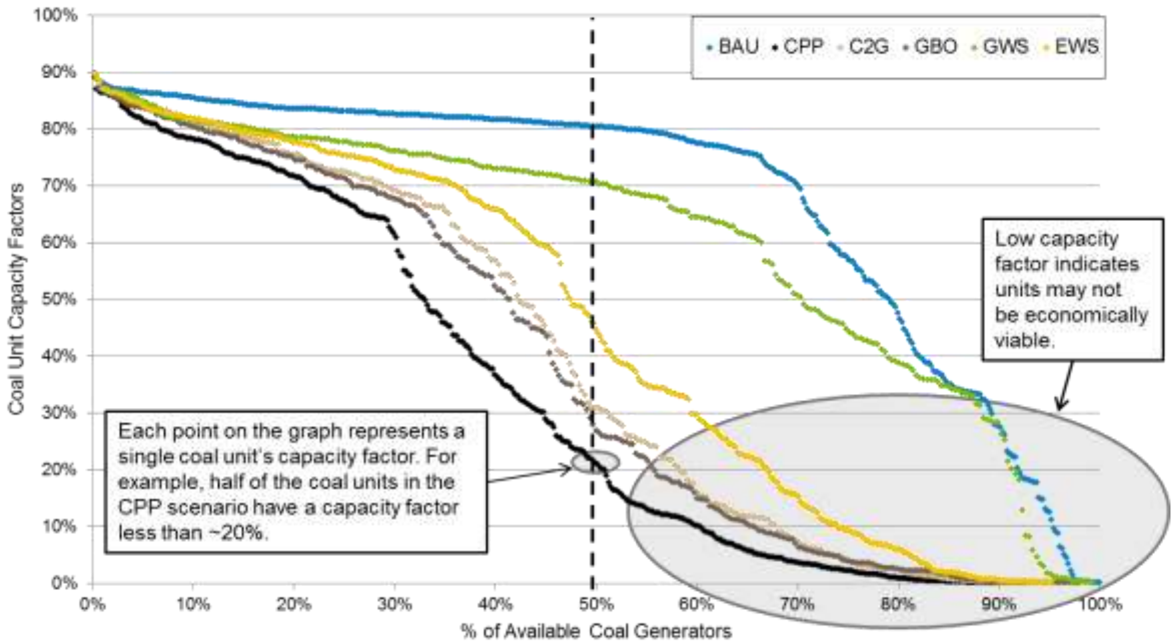


Figure 7 2030 Coal Unit Capacity Factors

Several observations can be made about the operation of coal units in the Phase III study:

- In the GWS scenario, a combination of coal capacity retirements and renewable generation offsets allows the remaining coal units to operate at capacity factors similar to those in the BAU.
- The EWS scenario has no coal retirements but a high level of renewable generation and energy efficiency, allowing coal units to dispatch slightly more than the C2G and GBO scenarios.
- C2G and GBO have very similar coal unit capacity factors given the common definitions, with higher average capacity factors than CPP due to the 25% coal capacity retirements.

The CPP scenario has the lowest coal capacity factors due to the fact that there are no retirements in this scenario. Here, the only compliance option is to increase dispatch of gas units and decrease dispatch of coal units. Despite no additional coal retirements modeled in the CPP scenario, the performance of the coal fleet differs significantly from historical operations. In this scenario, coal units perform similarly to peaking units and have increased amounts of cycling. This may impact a coal unit's ability to continue to economically remain online.

Moving from state to regional compliance scenarios also greatly changed individual coal unit capacity factors.

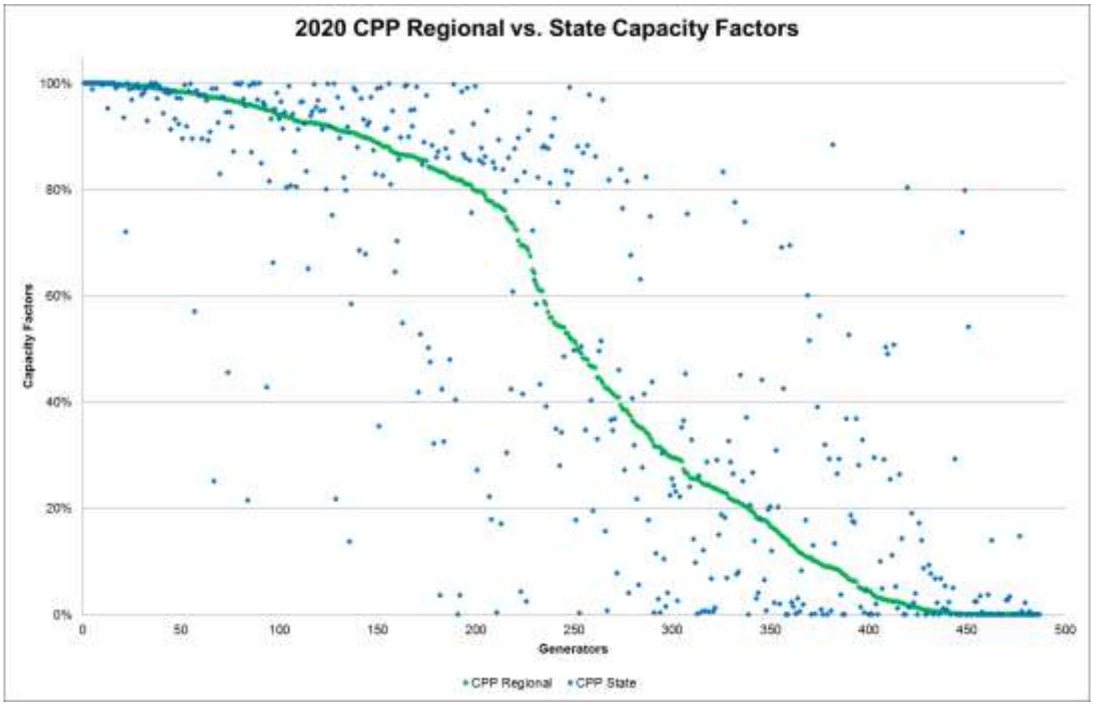


Figure 8 2020 CPP Regional vs. State Capacity Factors (Unit Comparison)

This chart shows the capacity factor of each generator under a regional approach (in green), and compares it to the capacity factor of the same generator (in blue) under a state-level compliance approach.

- 30% of coal units changed capacity factor by more than 5%
- 20% of coal units changed capacity factor by more than 10%
- 4% of coal units changed capacity factor by more than 50%

Further, coal units experienced significant changes in cycling due to the CPP constraints. These changes merit further study as MISO moves on to the analysis of the final rule.

	Total Starts	Avg. Starts	Total MW Travel[7]	Avg. MW Travel	Idled Units[8]
2030 BAU	7,168	47	8,463,021	56,046	0
2030 CPP – State	14,825	98	14,553,126	96,378	9
2030 CPP – Sub-Regional	14,953	99	14,968,013	99,126	5
2030 CPP - Regional	15,494	103	15,240,617	100,931	11

Table 5 Coal Unit Performance Metrics

[7] MW Travel = Ramp Up + Ramp Down
[8] Units that did not run for compliance reasons

Aggregate coal performance is similar despite a large change from state-level compliance to regional compliance. This chart shows how MISO coal units perform under both compliance implementations. Overall capacity factors for coal units are largely unchanged leading to the conclusion that while compliance regions make a material difference in the performance of individual coal units, they have less impact on the performance of the coal fleet in aggregate.

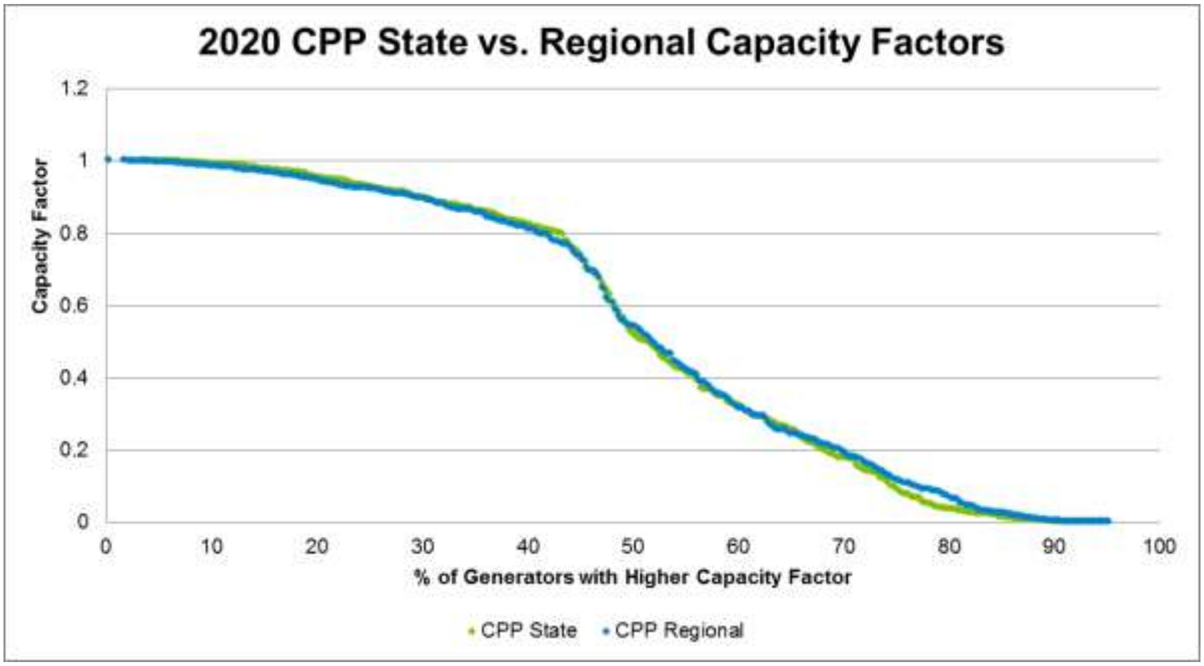


Figure 9 2020 CPP Regional vs. State Capacity Factors (Overall)

In addition to changes in coal unit dispatch, combined cycle and combustion turbine gas units experience a significant increase in dispatch in the CPP scenario, as detailed in Figure 10.

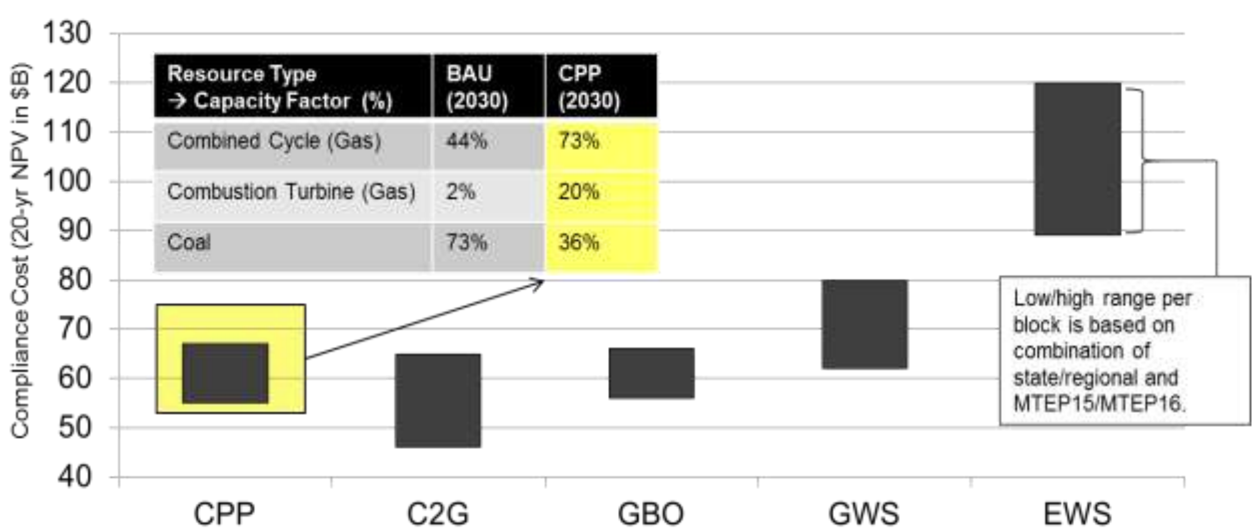


Figure 10 Compliance Costs and Capacity Factors for All Scenarios

The implications of these changes in dispatch were not studied in Phase III but may be considered in MISO's analysis of the final rule.

3.2.3 Must Run Implications

In the MISO economic models large coal units (>300MW) are assumed to be always committed (Must Run). In preliminary analysis, it was found that some states could not comply and experienced very high CO_2 prices with this assumption. In this analysis, coal units are allowed to cycle. This section explores the implications of this decision.

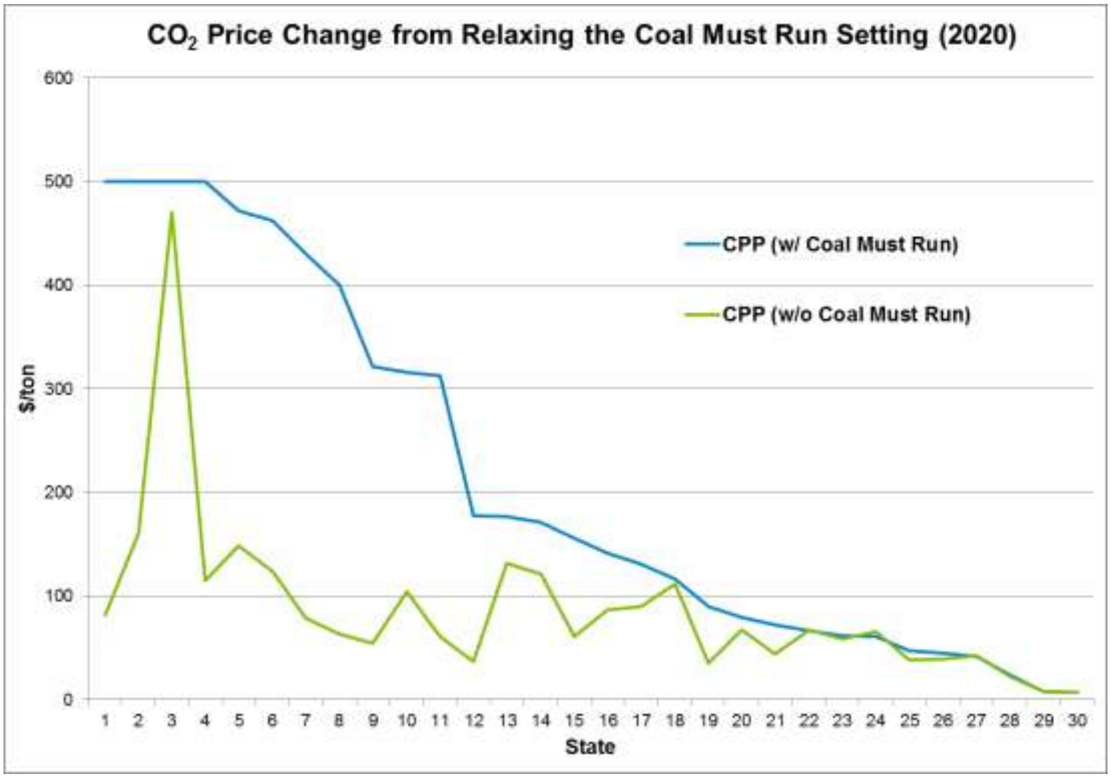


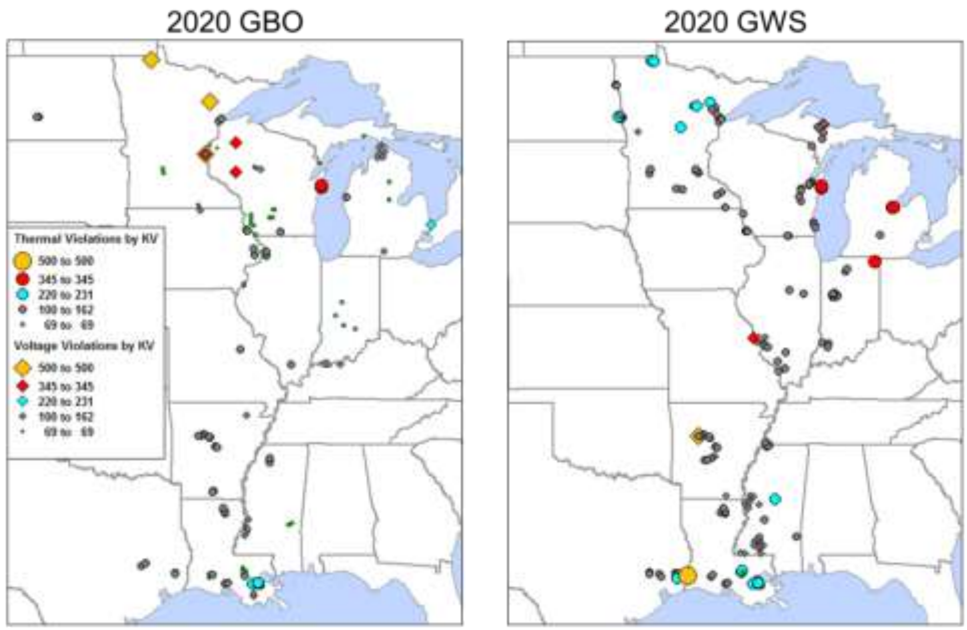
Figure 11 CO2 Prices with Relaxed Must Run Setting

- BAU scenario:
  - Coal generation changes less than 0.5% when removing the must run setting
  - 2% of generation shifted among units after the setting was relaxed
- CPP scenario:
  - Coal generation changes 5% when removing the must run setting
  - Massive shift (22% of generation) in states with difficult compliance from higher CO_2 emitting coal units to lower emitting coal units
- Coal generation in both scenarios is replaced by mostly combined cycle units, with some steam turbine gas

This brief analysis indicates while it is appropriate to have large coal units set to must-run in scenarios that mirror current operations, it becomes a barrier to system flexibility when moving into a world with large, compliance-driven changes. More work will need to be done to fully understand the impact on coal units and the rest of the system as the transition to a less carbon intensive fleet occurs.

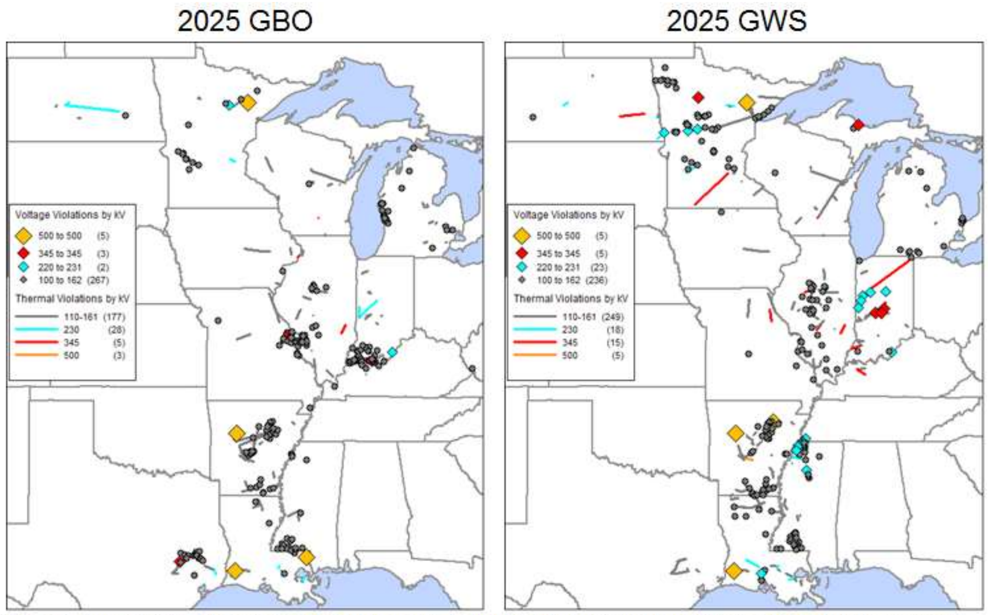
3.3 Reliability Impacts

Figure 12 and Figure 13 show the location of transmission facilities with reliability violations under CPP compliance scenarios analyzed for both the 2020 and 2025 timeframes. Detailed results are posted on the MISO FTP site and were used for stakeholder review to inform the development of needed transmission reinforcements.



Maps show reliability impacts in 2020 for Gas Build Out (GBO) and Gas Wind and Solar (GWS) scenarios.

Figure 12 2020 GBO and GWS Reliability Impacts



Maps show reliability impacts in 2025 for Gas Build Out (GBO) and Gas Wind and Solar (GWS) scenarios.

Figure 13 2025 GBO and GWS Reliability Impacts

Analysis of the 2020 GBO scenario indicated 1,385 Bulk Electric System (BES) thermal constraints for 78 different facilities across the MISO region. Low voltage issues were pre-existing but worsened under the new generation scenario. The 2025 GBO analysis identified 3,585 BES constraints for 213 different facilities and 6,995 new low voltages BES constraints for 277 different locations.

Analysis of the 2020 GWS scenario indicated 346 BES thermal constraints for 107 different facilities. Low voltages were observed for 144 constraints at 71 different locations. The 2025 GWS analysis revealed 4,342 BES constraints for 287 different facilities while 657 low voltage BES constraints were observed for 269 different locations.

Methods used for reliability analysis are described in Section 7.

3.4 Transmission Congestion and Solutions Development

The Phase III study encompassed efforts to identify economic transmission expansion needs under CPP compliance and accordingly, develop transmission solutions. Phase III analysis indicates that a significant amount of transmission in MISO is needed for full compliance with the draft CPP while maintaining cost effective delivery of reliable energy to consumers.

3.4.1 Economic Transmission Expansion Opportunities

High-level transmission congestion trends were driven by compliance approach, as well as placement and resource type of new capacity. Congestion levels per scenario and compliance approach (state-level versus regional), as measured by congested facility count, are presented in Figure 15.

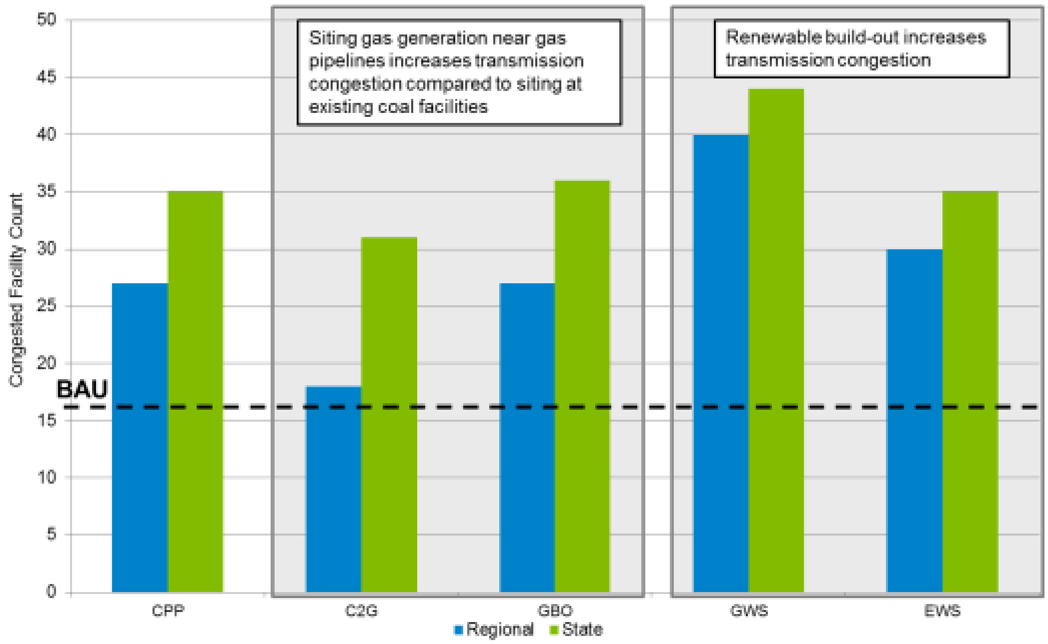


Figure 14 Congested Facilities

Transmission congestion increases under CPP compliance, though by incrementally less when employing a regional compliance approach. The C2G scenario saw the least amount of increase in congestion over BAU, largely because the "new" capacity in this scenario was coal-to-gas conversions, utilizing the existing transmission system built to handle power injections at these locations.

Larger increases in congestion in the GWS and EWS scenarios are owed to renewables build-out, though these increases are somewhat mitigated by implementation of energy efficiency programs in the latter. Additionally, while the system does not lose any additional capacity in the EWS scenario, it does lose coal capacity in the GWS scenario, leading to even higher levels of congestion than would be caused by the new renewables alone.

For purposes of this study, economic transmission expansion needs were defined as highly congested flowgates, i.e., transmission lines with average annual shadow prices[9] of $5/MWh or greater.

Along with identifying transmission facilities that could benefit from cost effective mitigation measures, broader areas of congestion were identified. Specifically, areas containing low cost generation which is limited by transmission congestion are shown in Figure 15. In total 107 facilities were identified across the study region, also shown in Figure 15 . Potential new transmission projects can be developed by linking areas of red to areas in blue. This will create an outlet for the red areas (indicating transmission constraints) and deliver it to blue areas served by expensive generation running because of transmission congestion.

[9] Shadow price is the marginal utility of relaxing the limit of a congested flowgate by 1MW

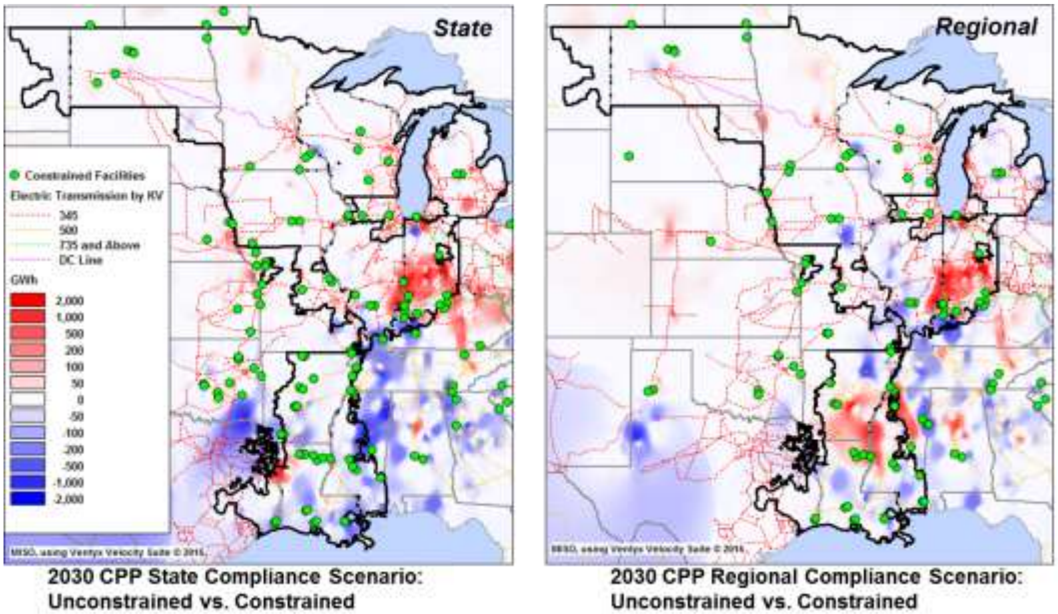


Figure 15 2030 State and Regional Compliance Congestion

Different opportunities arise under state-level versus regional compliance, though there is higher congestion overall in the state cases, and in the South and Central regions of MISO. Colored areas common to both maps are largely pre-existing congestion (i.e. not driven by CPP).

A potential budget was created to understand the amount of transmission that could be economically built to relieve new congestion driven by the implementation of the draft CPP. These numbers were developed by examining the generation costs between unconstrained (electric transmission line limits are not enforced) and constrained (limits are enforced) production cost simulations for the study scenarios and years. These numbers were then interpolated between years and extrapolated out to create a 20 year stream of benefits. The benefits for the first five years were taken exclusively from the BAU scenario to limit bias caused by the implementation of the CPP in 2020. The present value of the benefits was then calculated and multiplied by 70%. This metric is a rule-of-thumb that is used to find the amount of benefits which can realistically be captured through transmission expansion. Table 6 shows the result of this calculation for each scenario.

	CPP	C2G	GBO	GWS	EWS
Budget for Economic Transmission ($B)	**8.7 / 7.4**	**8.8 / 6.6**	**8.7 / 6.8**	**10.6 / 8.5**	**13.5 / 10.8**

Table 6 Budget for Economic Transmission

3.4.2 Development of Transmission Solutions

Across scenarios and years studied, 107 unique congested flowgates were identified. Solutions to address identified areas of transmission congestion were then solicited from stakeholders. In addition, MISO considered transmission projects that had been evaluated for previous Market Congestion Planning Study (MCPS) cycles.

The cost per portfolio was deemed a lower end estimate of transmission needed for economic transmission expansion under CPP compliance, as modeled.

In total, 34 transmission projects (Figure 16) were matched with congested areas across MISO, based on congestion mitigation as evidenced in previous MISO studies.

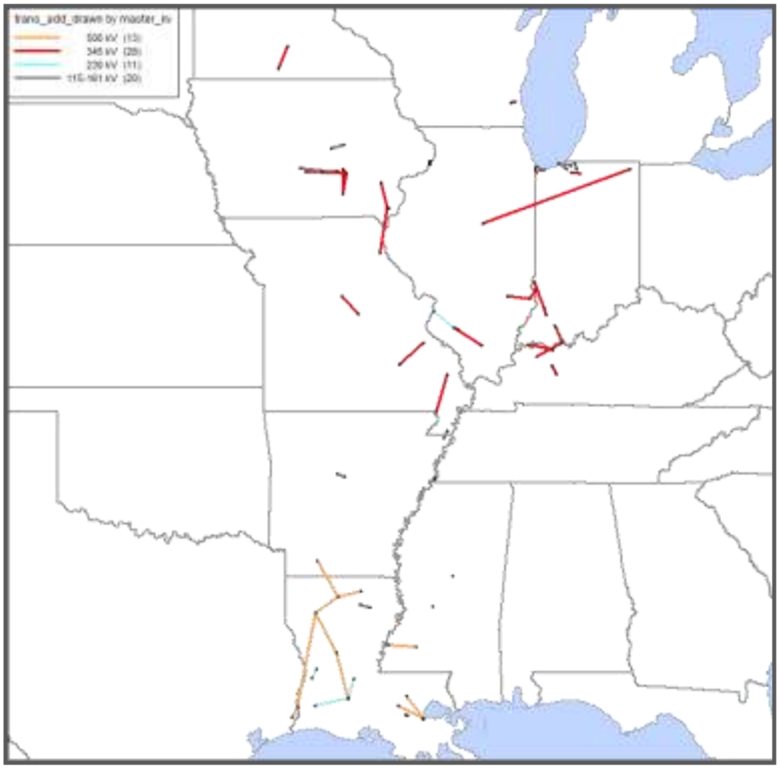


Figure 16 Map of 34 Transmission Projects Studied

Next, ten transmission portfolios—one each for state and regional approaches to compliance, per scenario—were then formulated using combinations of the 34 individual projects. Project groupings attempt to balance the cost of upgrades with the benefits of congestion relief, and were based on proximity to one another and mitigation of interconnected elements. These portfolios were designed to address the most congested areas per scenario, the mitigation of which would produce the largest value. The total costs for each portfolio are listed in Section 13. Costs were supplied by individual submitter.

The transmission portfolios and budget developed for economic transmission represent approximate bookends for economic transmission expansion under the scenarios modeled. Additional transmission expansion will likely be needed to address reliability concerns. Cost/benefit analysis indicates all of the portfolios studied would pass the B/C threshold of 1.25 within the context of Phase III.

3.5 MISO State CO_2 Emission Rates

Emission rates for each state were taken from the EPA's draft CPP and directly input into the model. This section details how MISO states performed against their targets in state runs, and also how regions performed in the state runs.

Several states were naturally compliant in the BAU scenario given their current capacity trajectories, and relatively modest reductions were needed across scenarios. Alternatively, some states have a relatively high compliance burden and thus a more difficult time complying given the options studied in Phase III. That said, in the modeled scenarios all states complied or nearly complied. Emission rates by year and scenario can be found in Section 14. It should be noted that those states that didn't comply may have experienced difficulty in part due to the study design (i.e. capacity and siting assumptions), and does not necessarily imply that the state will be unable to meet emission rate targets.

Regional and sub-regional rates are based on the actual generation from the state runs to hold the new compliance regions equitable. The exact methodology is detailed in Section 4. Larger compliance regions had more flexibility and an easier time complying. All new compliance regions were able to comply with the newly calculated targets.

3.6 Rate vs. Mass Based Compliance

Phase III used rate based compliance modeling to align with the interpretation of the draft rule CPP language. However, a set of tests was conducted to better understand the differences between rate and mass based compliance modeling. The model was first configured to optimize under a rate-based approach. Total emissions were tracked and subsequently entered into a new model as an input to optimize under a mass-based approach. The following models were run, with the performance and emissions of new and existing units being examined:

- Mass-based compliance
  - Existing units only
  - Existing and new units
  - Capacity expansion
- Rate-based compliance
  - Existing units only
  - Existing and new units
  - Capacity expansion

Figure 17 shows the generation from new and existing generators under mass and rate based approaches, with the compliance target assigned to existing units only.

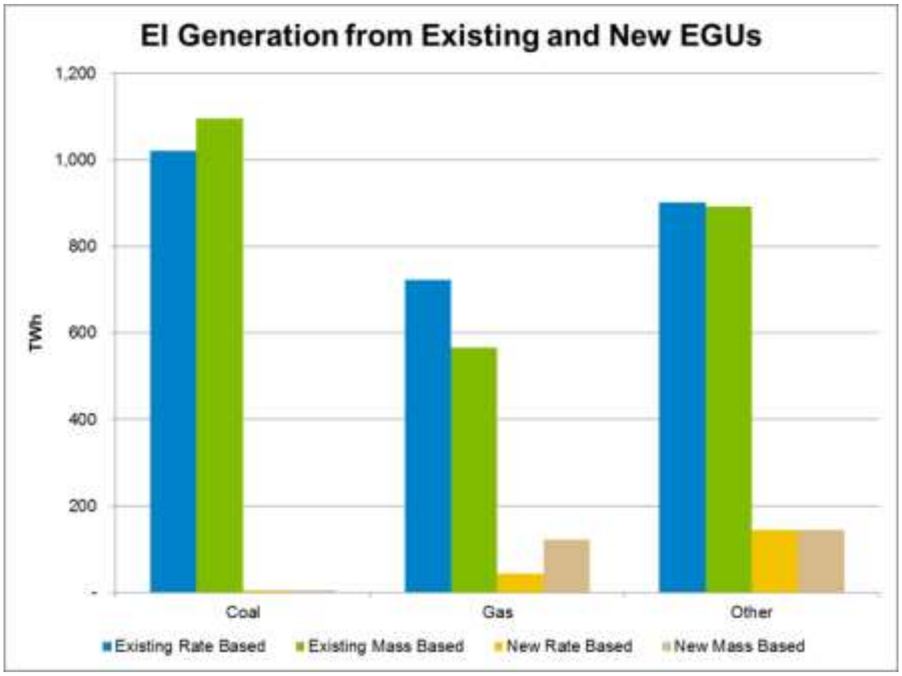


Figure 17 EI Generation from Existing and New EGUs under Rate and Mass Compliance

When only existing units are included in the emissions constraint, existing coal units and new gas units increase production under a mass based approach. Existing gas units decrease production under mass based compliance. Total emissions from existing and new units deviate by 6% between mass and rate based compliance.

The following graph shows the generation from all units under mass and rate based approaches, with the compliance target assigned to new and existing units.

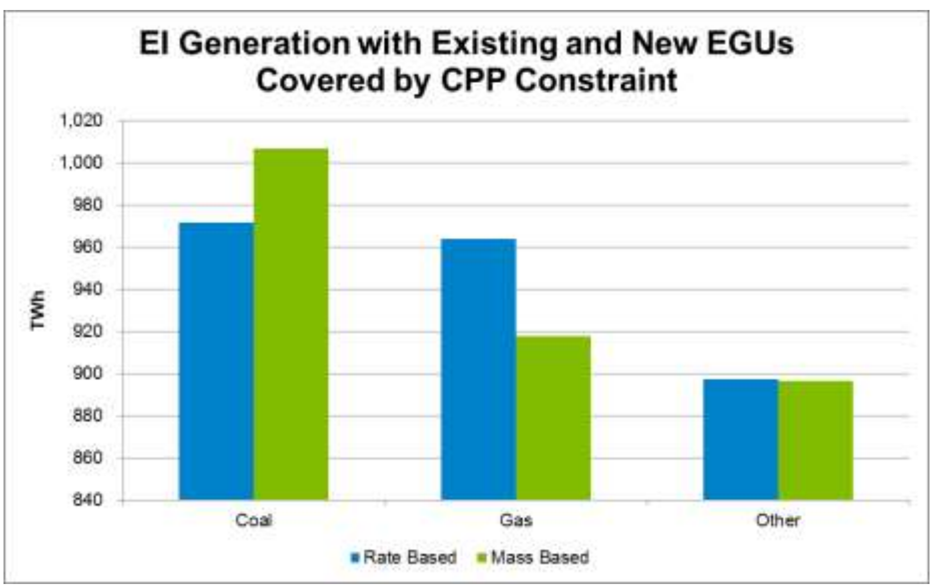


Figure 18 EI Generation with Existing and New Units Covered by CPP Constraints

When both existing and new units are included in the emissions constraint, the change in generation is similar. Coal units generate more under mass based compliance, while gas is backed down. Moving to mass based compliance causes the total system emissions rate to deviate by 1%.

Changes in capacity expansion are material when switching from mass to rate based compliance (Figure 19).

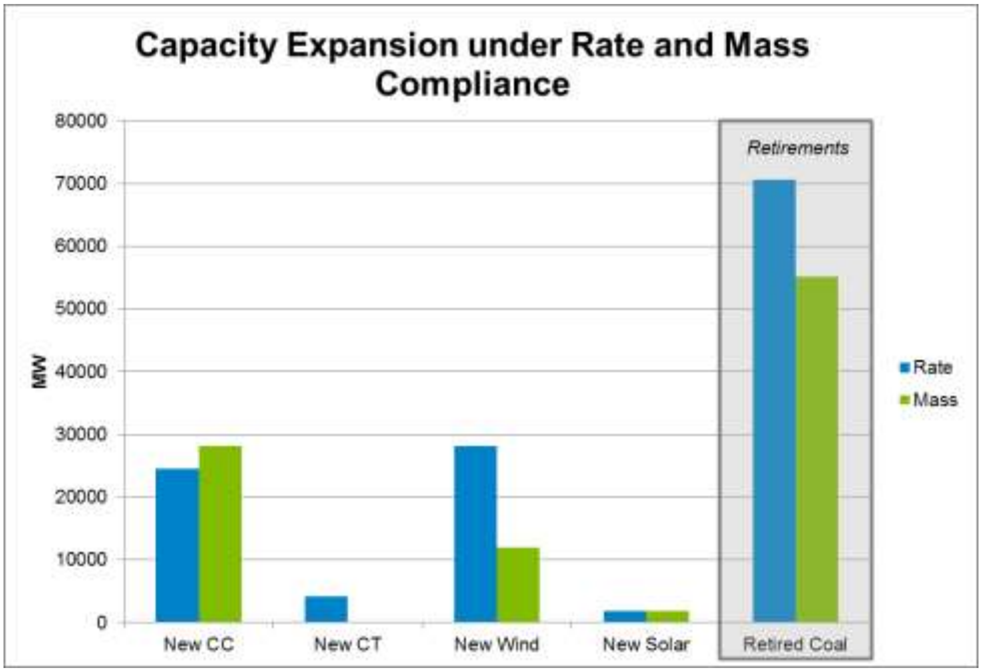


Figure 19 Capacity Expansion under Rate and Mass Compliance

Mass based compliance produces more combined cycle build-out but less build-out of renewables. Rate based compliance produces a larger amount of renewables and a significant amount of coal retirements. When the model is solved under a mass based constraint, capacity expansion is less reliant on renewables since the model no longer includes the double counting of renewables and shifts instead to new gas.

4 Study Approach

The study is designed to provide a robust and reasonably realistic representation of a world in which the EPA's draft Clean Power Plan (CPP) is fully implemented. Scenarios are derived and implemented to capture a wide range of compliance strategies without leaving the bounds of the draft rule. Implementation of the draft rule will take the form of capacity additions and retirements coupled with constraints representing the EPA's CO_2 rate targets on state, sub-regional and regional levels.

Phase III consists of both reliability analysis, using PSS/E, and production cost analysis, using PLEXOS. These models were chosen because of MISO's experience with them in past analyses, along with functionalities that align with study needs. The study aims to create similar representations of the underlying infrastructure and use similar regulatory and economic assumptions in both models.

In order to capture the early, mid- and late-stage impacts of compliance, the years 2020, 2025 and 2030 were modeled. The first year of compliance is 2020, according to the draft rule, with a final compliance target scheduled for implementation in 2030. The 2025 model captures the impacts of complying with the interim emissions target for 2020-2029 as defined by the EPA in the draft rule.

4.1 Modeling the EPA's CO_2 Rate Goals

The EPA proposed rate goals (lbs CO_2/MWh) for each state for the interim (2020-2029) and the final (2030 onward) periods of compliance. The calculation of these rate goals is illustrated in Equation 1.

$$\mathbf{Rate}\left(\frac{\mathbf{lbs}}{\mathbf{MWh}}\right) = \left[\frac{\mathbf{statewide\ CO_2\ emissions\ from\ affected\ thermal\ power\ plants\ (lbs)}}{\mathbf{statewide\ electricity\ generation\ from\ affected\ thermal\ plants} + \mathbf{renewable\ energy} + \mathbf{nuclear\ energy}^* + \mathbf{energy\ efficiency\ (MWh)}}\right]$$

Equation 1 EPA's Draft Rule Emissions Rate

The numerator in the equation is the sum of CO_2 emissions in a given state from the affected Electric Generating Units (EGU), which are defined as "any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014".[10] The denominator is the sum of the electricity generation in each state excluding existing hydro and new thermal resources. Neither the emissions from new[11] fossil fuel units nor the electricity they generate are included in the rate equation.

Nuclear units currently under construction, as well as approximately 6% of nuclear capacity that is considered "at-risk", are included in the denominator of the rate calculation. This "at-risk" capacity has been identified by the Energy Information Administration (EIA) in their Annual Energy Outlook as capacity that, due to varying economic factors, might be a candidate for retirement. However, in light of the draft CPP, the EPA assumes that it would be more cost-effective to leave this "at-risk" nuclear capacity in service, and thus this 6% of nuclear capacity is included in the EPA's rate calculations. The amount of nuclear capacity considered to be "at-risk" for each state can be found in the EPA's Technical Supporting

[10] Regulatory Impact Analysis for the Carbon Pollution Emission Guidelines Supplemental Proposal
[11] CO_2 emissions from newly constructed thermal units are addressed in Section 111(b) of the Clean Air Act.

Document "GHG Abatement Measures."[12] Phase III assumes that 6% of all nuclear generation is counted in the denominator in accordance with the EPA's modeling.

4.2 Modeling State-Level Compliance

State-level CO_2 targets in a world with regional dispatch poses a modeling challenge. To represent the real-world boundaries of different ISO/RTO markets in the model, a hurdle rate (essentially a cost to bias the dispatch of a unit within a pool to that pool's market) is applied. A single security-constrained economic dispatch or SCED is simulated for the Eastern Interconnect. The SCED simultaneously optimizes the dispatch, takes into account the hurdle rates, and thus, the pool boundaries, and tries to comply with the CO_2 constraints added to the model. This approach—modeling hurdle rates to represent pool boundaries, along with the application of constraints in the SCED—is common to production cost modeling.

Rate constraints on emissions can be represented directly in PLEXOS, as opposed to modeling a CO_2 cost as a proxy for a rate constraint. Furthermore, emissions rate constraints at the state-level can be accounted for in the solution algorithm at the same time as dispatch occurs at the market pool level.

To represent state-level compliance in PLEXOS, the constraint equation is formulated per the EPA's proposed rate calculation for each state. Affected generators that are physically located within a state must meet an average, over a 24-hour period, of the EPA's proposed CO_2 annual rate target for that state.

4.3 Modeling Sub-Regional Compliance

Sub-regional compliance was also modeled as a sensitivity for select scenarios. Only the MISO region was broken into sub-regional portions for this sensitivity analysis while the external regions remained whole.

The methodology for modeling sub-regional compliance is similar to that of modeling state-level compliance. Affected generators that are physically located within a sub-region must meet an aggregate of the EPA's proposed CO_2 state rate targets for that sub-region.

In the Phase III study, sub-regions were based on MISO's portions of the states defined below and as seen in **Error! Reference source not found.**:

- **North:** Montana, North Dakota, South Dakota, Minnesota, Iowa
- **Central**: Wisconsin, Missouri, Illinois, Indiana, Michigan, Kentucky
- **South**: Mississippi, Louisiana, Texas, Arkansas

[12] EPA Technical Supporting Document "GHG Abatement Measures"

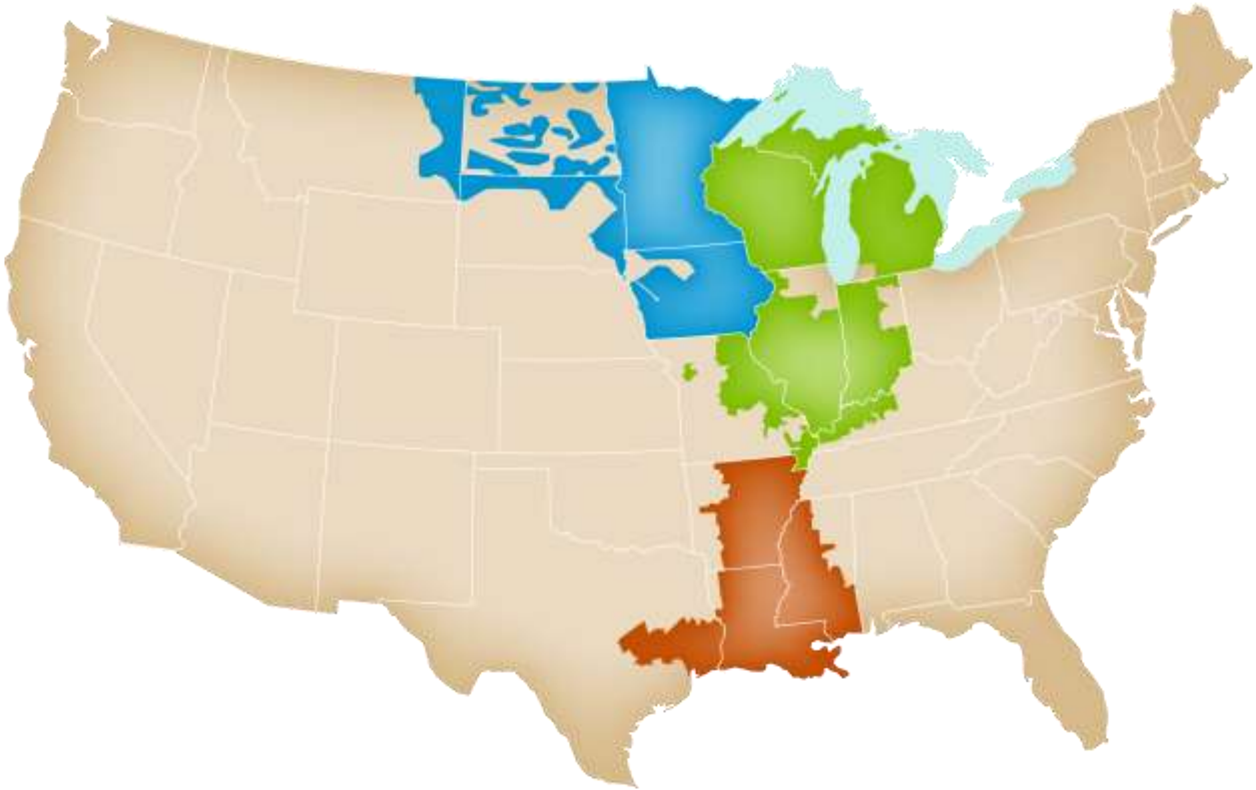


Figure 20 MISO Sub-regions Used in Phase III Analysis

To model sub-regional compliance, emissions targets per sub-region were determined by summing the emissions and generation from the state-level analysis (based on the portion of the state that is in MISO) to establish a sub-regional emissions target. Then, generators within each sub-region were dispatched to meet this average target.

4.4 Modeling Regional Compliance

Regional compliance was also modeled for each studied scenario. This includes MISO along with these neighboring external regions: MRO, SPP, PJM, TVA, SERC and NYISO.

To model regional compliance, first the emissions and generation from the state-level analysis were summed; second, a region-wide emissions reduction target was established; and third, generators within each pool were dispatched to meet this average target. Regional boundaries supplant state boundaries in this model.

The averaging technique, which uses state-level modeling to determine regional targets, is done to limit deviations created by using historical state dispatch when moving to a regional approach. It also keeps the total emission reductions in line with the state-level modeling.

5 Scenario Analysis

The base 2015 MISO Transmission Expansion Plan (MTEP15) economic planning dataset underlies each scenario; specific data elements, detailed below, are modified per scenario. CPP compliance was modeled at the state-level in each relevant scenario. This means that the EPA's proposed state, rate-based CO_2 emissions targets were modeled as constraints on the emissions produced by the affected generators per state. Regional (MISO-wide) and sub-regional (defined later in this document) compliance were modeled for select scenarios.

Six scenarios were used for the Phase III CO_2 study:

1. Business-as-Usual (BAU)
2. CPP Constraints (CPP)
3. Coal-to-Gas Conversions (C2G)
4. Gas Build-Out (GBO)
5. Gas, Wind and Solar Build-Out (GWS)
6. Increased Energy Efficiency with Wind and Solar Build-Out (EWS)

5.1 Business-as-Usual (BAU)

In the first scenario, the system is modeled without CPP constraints. All of the assumptions for the MTEP15 BAU model apply, including Mercury Air Toxics Standards (MATS)-related coal capacity retirements.

The figures for MATS retirements assumed in the MTEP15 model are based on MISO's 2011 EPA Impact Analysis[13].

Additional assumptions underlying the base dataset for the MTEP15 BAU model are covered in Section 8.

5.2 CPP Constraints (CPP)

For the remainder of the scenarios, the CPP constraints are applied, as defined in Section **Error! Reference source not found.**, and the system is dispatched to comply. In the CPP scenario, no generator retirements are modeled beyond those assumed for the MTEP15 BAU model. Similarly, no new electric generation capacity is added to the model beyond that which is added in the MTEP15 BAU model.

5.3 Coal-to-Gas Conversions (C2G)

In addition to the 12.6 GW of MATS-related coal unit retirements projected in the MISO footprint, 25% of the remaining coal capacity per region in the Eastern Interconnect is incrementally converted to gas-fired combined cycle units. The level of retirements is informed by the results of MISO's Phase II CPP analysis, which modeled sensitivities around coal capacity retirements, including low (0 GW), medium (25% or approximately 14 GW in the MISO footprint) and high (50% or approximately 28 GW in the MISO footprint) levels. The results indicated that a medium level of retirements (beyond MATS-related retirements) was the most cost-effective strategy for compliance with the CPP among those studied.

The process for selecting and siting coal units to retire in the C2G scenario is:

[13] See https://www.misoenergy.org/Library/Repository/Study/MISO%20EPA%20Impact%20Analysis.pdf.

1) Select oldest coal units in each region (e.g. MISO, PJM, SPP), amounting to approximately 25% of the coal fleet capacity per region.
2) Convert these coal units to gas units in the model. As conversions, units will remain at the same site (same bus) and of the same size (same capacity).

Five percent of the coal fleet is converted in the 2020 model, with the remainder of the conversions implemented in the 2025 and 2030 models. The assumption underlying the timing of conversions is that capacity will be removed from the system incrementally (i.e. 5% per year from 2020 through 2024, for a total of 25% in 2024), versus all in one year, due to resource adequacy considerations. Figure 21 shows all of the coal to gas conversions implemented by 2030.

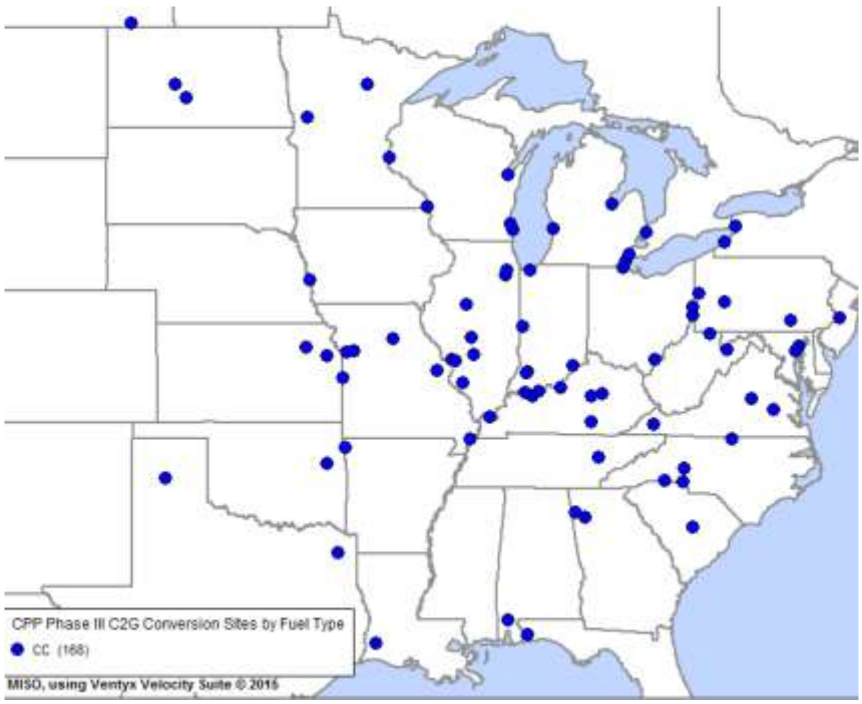


Figure 21 C2G Coal to CC Conversions

5.4 Gas Build-Out (GBO)

In addition to the 12.6 GW of MATS-related coal unit retirements, 25% of the remaining coal capacity per region in the Eastern Interconnect is incrementally replaced by new gas units, with a balance of approximately 80% gas-fired combined cycle and 20% gas-fired combustion turbines. The timeline for retirement implementation is the same as that for the conversions in the C2G scenario.

The process for selecting coal units for retirement and for siting replacement gas units in the GBO scenario is:

1) Select oldest coal units in each region (e.g. MISO, PJM, SPP), amounting to approximately 25% of the coal fleet capacity per region.
2) For MISO:
    a. Replace retired coal units with 600 MW gas units, per company, as forecasted by EGEAS in the Phase II study.
3) For the rest of the footprint modeled:

a. Replace retired coal units with 600 MW gas units, per company (replacement gas-fired capacity is approximately commensurate with coal capacity retirement on a company-by-company basis, i.e., companies with older coal units will see more gas unit build-out). The sum of the gas replacements is approximately equal to the lost coal capacity.

Within the company footprint, new gas units are sited according to the MTEP siting methodology (see Section 9 for further details).

Figure 22 details the locations of the retired units and capacity expansion units.

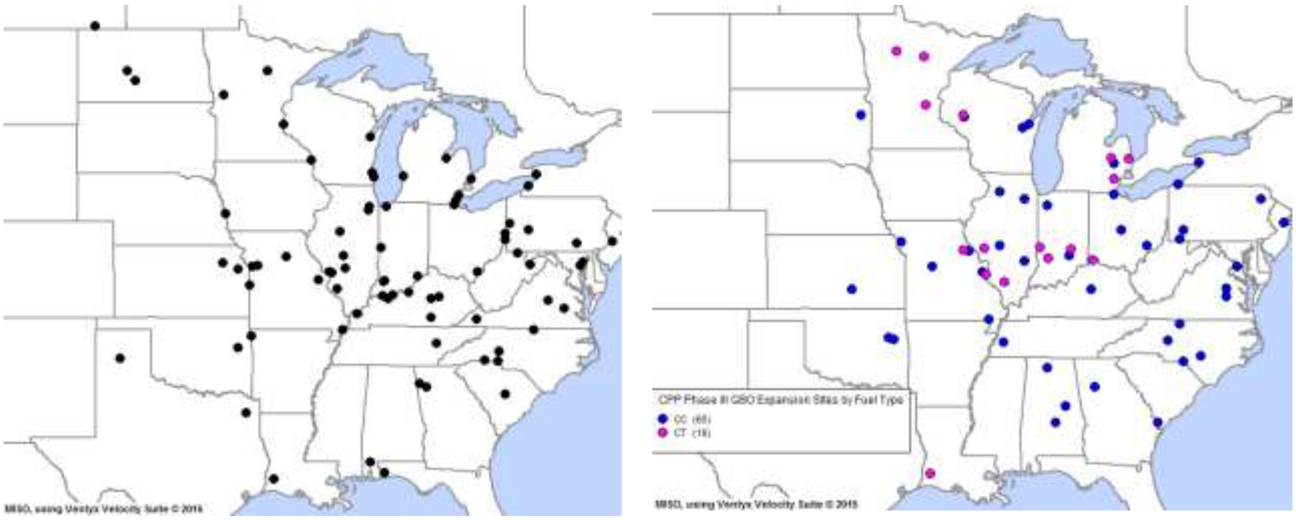


Figure 22 GBO Retirements (left), GBO Capacity Expansion (right)

The difference between C2G and GBO is in the siting and size (capacity, MW) of the replacement generation. The underlying assumption is that these two scenarios will bookend infrastructure expansion needs. The C2G scenario places new (converted) generators where there is already electric infrastructure but where there may not be the necessary gas infrastructure; the GBO scenario places new generators in the proximity to gas infrastructure but not necessarily at prime locations within the electric system.

5.5 Gas, Wind and Solar Build-Out (GWS)

In addition to the 12.6 GW of MATS-related coal unit retirements projected in the MISO footprint, 17% of the remaining coal capacity per region in the Eastern Interconnect is incrementally converted to wind and solar resources while 13% of the coal capacity is converted to new gas units.

The process for selecting coal units to retire in the GWS scenario was based on a retirement screening using PLEXOS which identified retirements based on the intensity of EPA state rate targets and the existing generation of the system.

Fifty percent of the retirements are implemented in the 2020 model, 90% in the 2025 model and 100% in the 2030 model. The assumption underlying the timing of retirements is that capacity will begin retirement before implementation of the CPP in an effort to ease compliance in the first year.

New capacity is sited according to the MTEP siting methodology (see Section 9 for further details). Below are two maps showing the retirements and capacity expansion units for the GWS scenario.

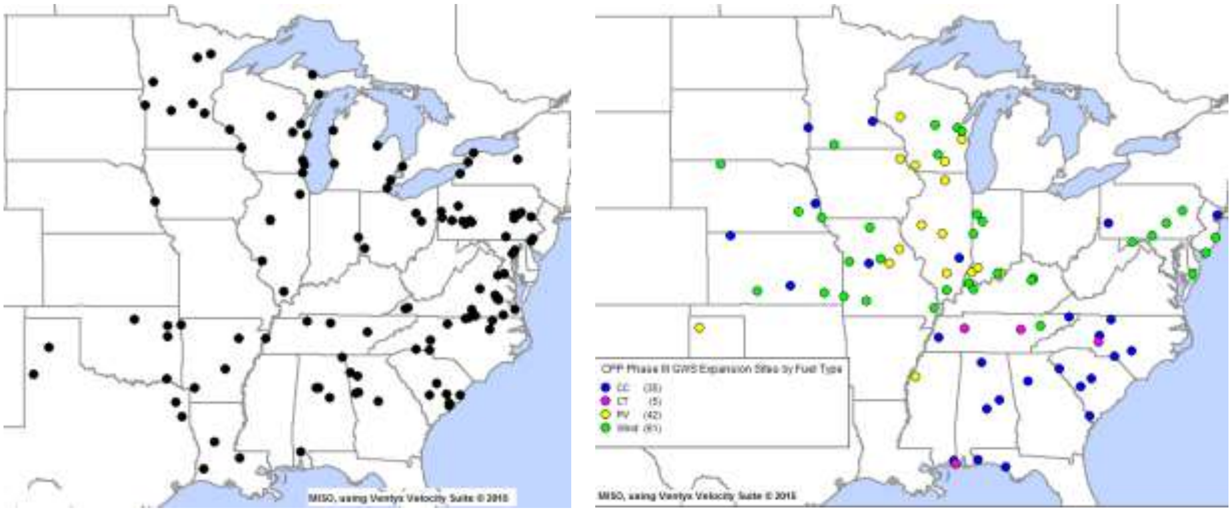


Figure 23 GWS Retirements (left), GWS Capacity Expansion (right)

5.6 Increased Energy Efficiency with Wind and Solar Build-Out (EWS)

In the EWS scenario, increased penetration of energy efficiency (EE) is modeled at rates representative of EPA's building block four[14] and is assumed to be a bookend for high-level penetration of energy efficiency. EE rates ramp up from their current levels at 0.2% per year beginning in 2017 until they reach the 1.5% annual target. Once the target is reached, a 1.5% EE level is maintained year-over-year. See Appendix 10 for the EPA's assumptions on the potential for avoided energy sales per state.

Rate targets for each state are adjusted to give credit for the EE implementation. This is done by removing the EE term from the denominator of the rate calculation thereby increasing each state's rate target.

This scenario also includes increased build-out of wind and solar resources, driven by a 15% footprint-wide Renewable Portfolio Standard (RPS) target. Current RPS targets account for about a 10% target during the same time period. Renewables build out includes wind and solar (66% wind and 34% solar) with the exception of SERC which only includes solar. Additionally, 25% of SERC's renewables requirement will be distributed across SPP, and 25% of it will be distributed across MISO. The renewables will be sited according to the MTEP siting methodology (see Section 9 for further details), and installed in even increments in 2020, 2025, and 2030.

Figure 24 EWS Capacity Expansion details the siting of the solar and wind units across the study footprint.

[14] See "Technical Support Document: Goal Computation" and "Data File: Goal Computation - Appendix 1 and 2" at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

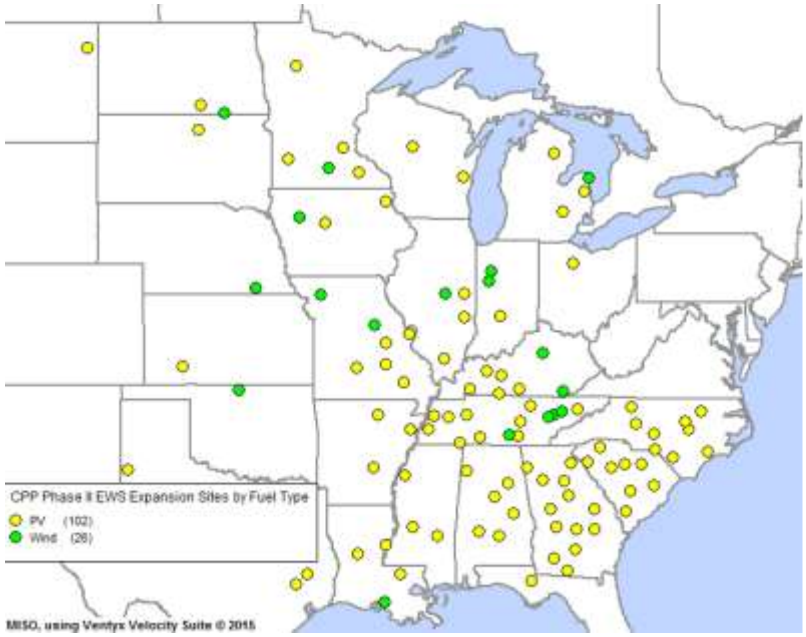


Figure 24 EWS Capacity Expansion

5.7 Tie-in to the Phase II Study

The selection of the Phase III scenarios was informed by the findings of MISO's Phase II CPP analysis. The results from the Phase II include capacity and energy impacts for a wide range of compliance strategies, under various economic and regulatory conditions[15].

The results of the Phase II analysis are illustrated by Figure 25. Each diamond in the graphic represents a single sensitivity and those diamonds that correlate to a scenario in Phase III are circled. The % reduction on the horizontal axis in the figure represents how far above or below the EPA's CO_2 emissions target a given compliance strategy is, according to the results of the analysis. "Zero percent" equates to exactly meeting the target, "negative" equates to failing to meet the target by the % indicated and "positive" exceeds the target by the % indicated. The target CO_2 level for Phase I and II was approximately based on the EPA's rate-to-mass conversion formula identifying qualifying units (existing fossil fuel-fired plants, incremental nuclear units, new renewables and new energy efficiency).

[15] More than 1,000 sensitivities around various levels of gas price, CO_2 price, coal unit retirements, demand and energy, Energy Efficiency (EE)/Demand Response (DR) penetration, nuclear unit retirements, and Renewable Portfolio Standard (RPS) levels were modeled in Phase II.

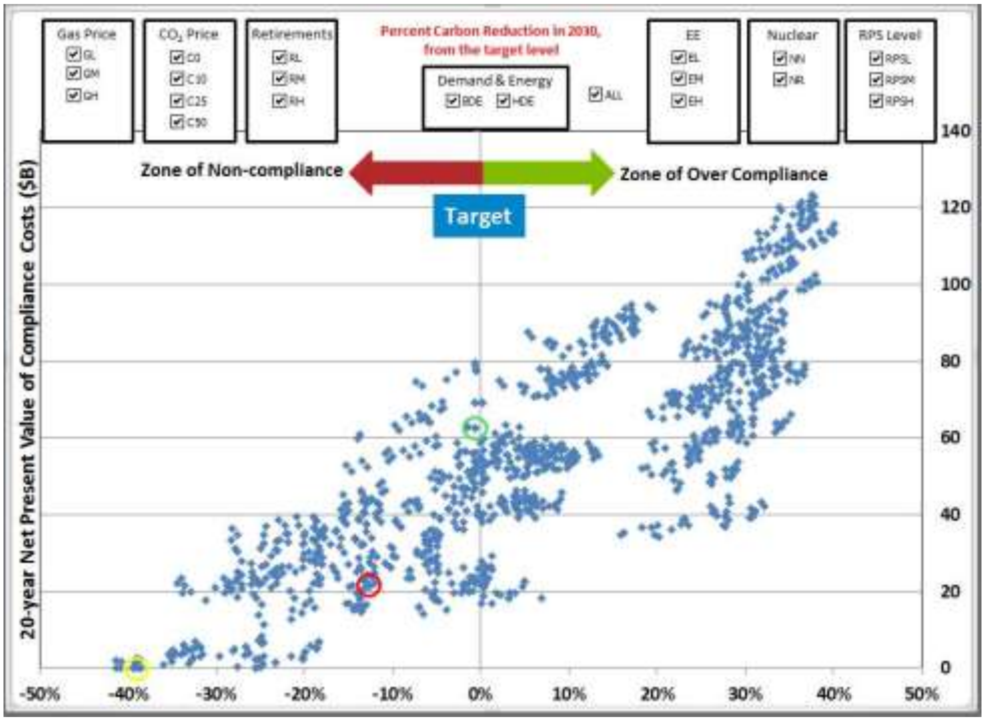


Figure 25 Results of the Phase II CPP Analysis (Phase III scenarios are circled)

The circled diamonds represent the sensitivities from Phase II used to develop scenarios for Phase III. The characteristics of the sensitivity for each scenario are listed in Table 7 below. It is worth noting that the BAU and CPP scenarios have the same set of characteristics, as well as the C2G and GBO scenarios. This is due to the fact that the CPP scenario is designed to assess the capabilities of the current system (as modeled by the BAU scenario) based solely on re-dispatch. The diamonds in the graph above do not include re-dispatch for CPP compliance.

Scenario	Gas Price	CO_2 Price	Retirement	Demand & Energy	EE	Nuclear Retirement	RPS Level
BAU	$4.30/MMBTU Henry Hub '14	$0	12.6 GW	0.8%	Mandated levels in MTEP BAU	No retirements	Current state mandates
CPP	$4.30/MMBTU Henry Hub '14	$0	12.6 GW	0.8%	Mandated levels in MTEP BAU	No retirements	Current state mandates
C2G	$4.30/MMBTU Henry Hub '14	$0	12.6 GW + 25% of coal capacity	0.8%	Mandated levels in MTEP BAU	No retirements	Current state mandates
GBO	$4.30/MMBTU Henry Hub '14	$0	12.6 GW + 25% of coal capacity	0.8%	Mandated levels in MTEP BAU	No retirements	Current state mandates
GWS	$4.30/MMBTU Henry Hub '14	$0	12.6 GW + 30% of coal capacity	0.8%	Mandated levels in MTEP BAU	No retirements	Current state mandates
EWS	$4.30/MMBTU Henry Hub '14	$0	12.6 GW	0.8%	1.5% of energy consumption	No retirements	15% footprint-wide RPS

Table 7 Tie-in between Phase II Sensitivities and Phase III Scenarios

While Phase III scenarios were developed from Phase II sensitivities, the differences in the tools used to do each analysis, as well as the objectives of each analysis, do not allow for direct comparison. The Phase II analysis modeled capacity expansion using EGEAS; the Phase III analysis will use PLEXOS to perform production cost analysis. The former models a 20-year study period without consideration of electric transmission and the latter, a single year of hourly dispatch with consideration of electric transmission. The generation capacity forecasted in EGEAS (i.e. the RRF units) is modeled in PLEXOS as part of the set of static generation capacity, with which a security-constrained economic dispatch is executed.

One of the outputs of the EGEAS model is CO_2 emissions produced by the operation of the generation fleet. In PLEXOS, the EPA's CO_2 emissions rate targets are represented as constraints on generation and the model minimizes production cost given this constraint.

5.8 Additional Modeling Assumptions

Typically, MISO economic models assume that coal units greater than 300 MW are always committed with "must run" status. Through the results of preliminary analysis, it was observed that some states could not comply with their rate targets and experienced unreasonably high CO_2 prices. To mitigate the inability of many states to comply, these must run statuses were relaxed for this study.

6 Gas System Modeling

The incorporation of detailed gas system modeling into the production cost portion of this analysis is new to MISO's CO_2 analysis, and new to transmission modeling in general at MISO. Over the course of Phase III, the inputs for this proof-of-concept model were refined in preparation for integrated gas-electric modeling for the final rule analysis.

The model representation of the gas system parallels that of the electric system, with individual pipelines and pipeline segments, gas nodes, gas storage and gas loads. These elements are briefly described in Figure 26**Error! Reference source not found.** and further defined in subsequent sections.

Symbol	Class	Description
	Gas Field	Field from which gas is extracted
	Gas Storage	Storage where gas can be injected and extracted
	Gas Pipeline	Pipeline for transporting gas
	Gas Node	Connection point to gas network
	Gas Demand	Demand for gas covering one or more nodes
	Gas Zone	A collection of Gas Nodes

Figure 26 Gas Modeling Objects: Symbols, Classes and Descriptions[16]

Much of the data for the gas model's underlying database is sourced from the Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study[17]. Some of this data is publically available and published in the EIPC Study report. A portion of the data gathered for the EIPC study is from Federal Energy Regulatory Commission (FERC) Critical Energy Infrastructure CEII) forms, and can be obtained by qualifying entities via request to FERC. The remainder of the data used in the EIPC Study is proprietary.

The PLEXOS gas network is represented in extensive detail, with thousands of gas infrastructure elements. Proprietary forecasts are used to develop gas production volumes and costs, as well as profiles for non-power gas demand. The following sections provide details around each major gas system component in the model, both as modeled by the vendor and as modified by MISO, if applicable, for purposes of the CPP study.

6.1 Gas Supply (Producing Fields)

Natural gas supply in the current version of the model is represented with ~1,000 individual gas injection points across the pipeline network. These injection points are a proxy for physical production fields. For each "gas field" (i.e. gas supply injection point), the user can add definition around production, including:

[16] Image from Energy Exemplar, 2015
[17] See http://www.eipconline.com/Gas-Electric_Documents.html

- Initial volume (MMcf): the volume of gas in the field at the start of the simulation[18]
- Production cost ($/MMBtu): the cost to produce gas at the field
- Can be defined as a curve or in bands, e.g. increasing costs as field is depleted
- Production volume (MMcf): the volume of production at the field
- Can be defined as production bands, e.g. decreasing production over time
- Min/max production (MMcf): the min or max level of production per field, defined for user-selected time interval, e.g. max daily or hourly production

Initial volume for gas production at a given gas field is set by the vendor[19] to a generic value (1x10^16 MMcf). The underlying assumption is that there is sufficient gas supply to serve gas demand. The implication of this assumption is that gas supply will not be a limiting factor on dispatch of gas-fired generators in the model. For CPP modeling, initial volume will remain at the generic value, with an underlying assumption that the limiting factor on gas supply from a given field or injection point is the maximum daily rate of production (MMcf/d).

The min production property is set to zero by the vendor and this value will be retained for MISO's use of the model in the CPP study. MISO will model max (daily) production capacity for each field based on proprietary IHS CERA forecasts for productive capacity[20] (forecasts are daily values, thus metric in model is daily). Production volume and production cost are modeled by the vendor with ten generic bands (Figure 27). The production bands will be replaced by proprietary forecasts from IHS CERA[21] for the CPP study.

[18] Property definitions are taken from the PLEXOS user manual
[19] Energy Exemplar is the vendor for PLEXOS.
[20] Productive capacity is defined by IHS CERA as an estimate of the pipeline-grade dry natural gas that a given play, basin or region can produce in a given year and that can be carried to market on the infrastructure assumed to exist at that time.
[21] Breakeven prices (USD per Mcf) are forecasted by IHS CERA for 2015 for eight US regions, as well as portions of Canada. Per IHS CERA's definition, full-cycle unit break-even prices are not normalized to Henry Hub but reflect economics for a play at the point of entry into the pipeline grid. Break-even prices (without and with natural gas liquids [NGLs] credits) are calculated at the play level for the "typical" well and include leasehold, finding and development (F&D), operating expenses (opex), royalty, taxes, and return. Capital costs are success-weighted and based on equipment needed for the "typical" well. Weighted-average cost of capital (WACC) is assumed to be 10%. Taxes are based on tax benefits available to all producers. Well useful life is assumed to be 20 years.

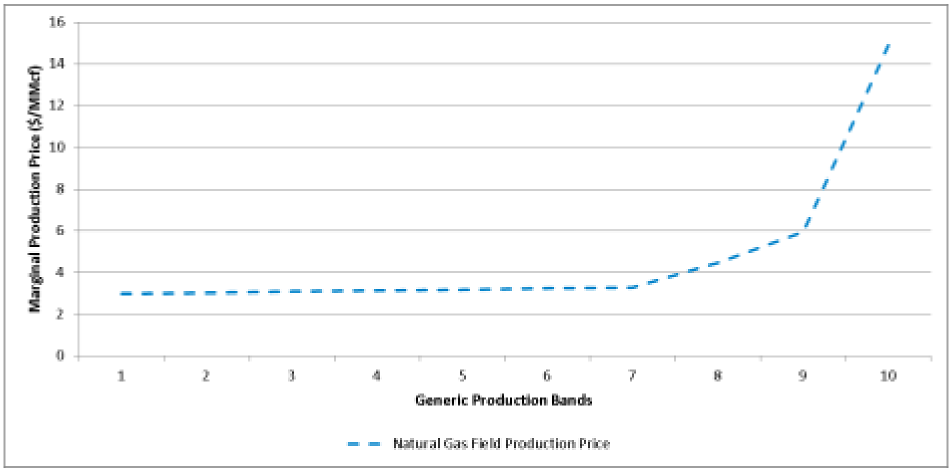


Figure 27 Generic Production Cost Bands in the Phase II PLEXOS Gas-Electric Model

Gas field objects will serve as proxies for real world pipeline pooling points, or aggregations of multiple gas injection points for a given pipeline or pipeline segment. These pooling points serve as liquid trading hubs for gas, and may be fed by gas injection from a variety of interconnected gas fields or pipelines. For example, gas supply on the Panhandle Eastern (PEPL) system (Figure 28) is represented in the model with gas field objects in the states of Kansas, Missouri, Illinois Michigan and Ohio.

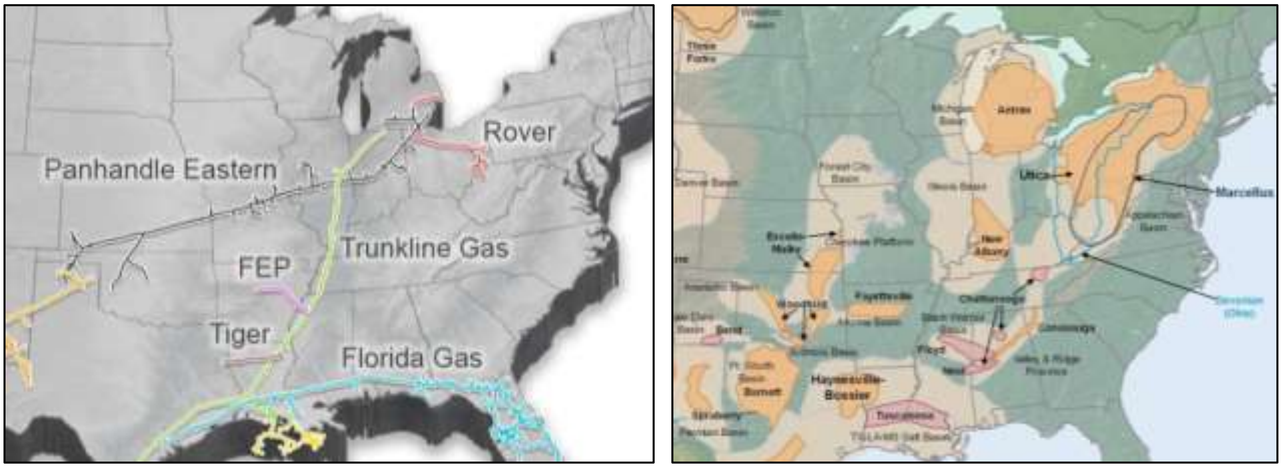


Figure 28 Energy Transfer gas network including Panhandle Eastern Pipeline (PEPL) System (left) and natural gas producing basins and plays (right)

The right image in Figure 28 shows the natural gas production fields from which PEPL shippers[22] could theoretically access gas supply directly. Figure 29 shows actual receipt points for the PEPL Market Zone (yellow triangles). The complexity of real world gas supply is challenging to capture in a model, especially one that spans the Eastern Interconnection. While the proxy pooling points in the model may not line up one-for-one with physical hubs they offer a reasonable approximation of aggregated gas supply.

[22] Gas pipeline tariff language generally refers to customers of pipeline capacity as "shippers".

Figure 29 Receipt Points for PEPL Market Zone[23]

6.2 Gas Pipelines

The North American natural gas pipeline network is represented in the model by hundreds of separate gas network elements, generally based on gas pipeline tariff definitions (e.g. a given pipeline is divided into Producing Zones A and B, and Market Zones C, D and E)[24]. Pipeline segments are interconnected with one another and with corresponding gas producing fields/gas supply points via gas nodes. Likewise, segments of two different pipelines, physically interconnected in the real world, are joined via nodes in the model.

For reference, Figure 30 shows the natural gas pipeline network (major interstate and intrastate pipelines) in the US.

[23] Image sourced from Energy Transfer, 2015; see http://peplmessenger.energytransfer.com/ipost/PEPL/maps/market-zone

[24] See Appendix B for a full listing of pipelines defined by Energy Exemplar in the PLEXOS gas model.

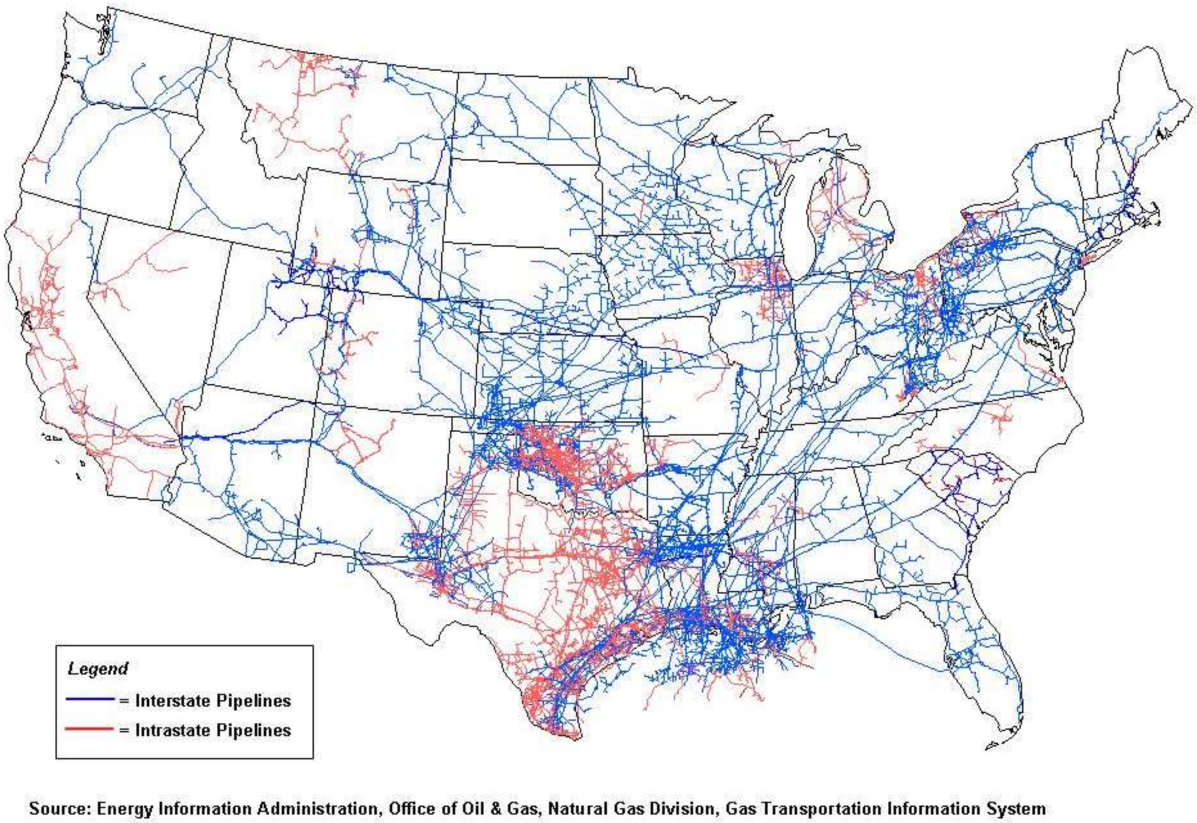


Figure 30 US Natural Gas Pipeline Network

An example of individual pipeline representation in PLEXOS is illustrated in Figure 31, which shows a partial representation of the Panhandle Eastern Pipeline (PEPL).

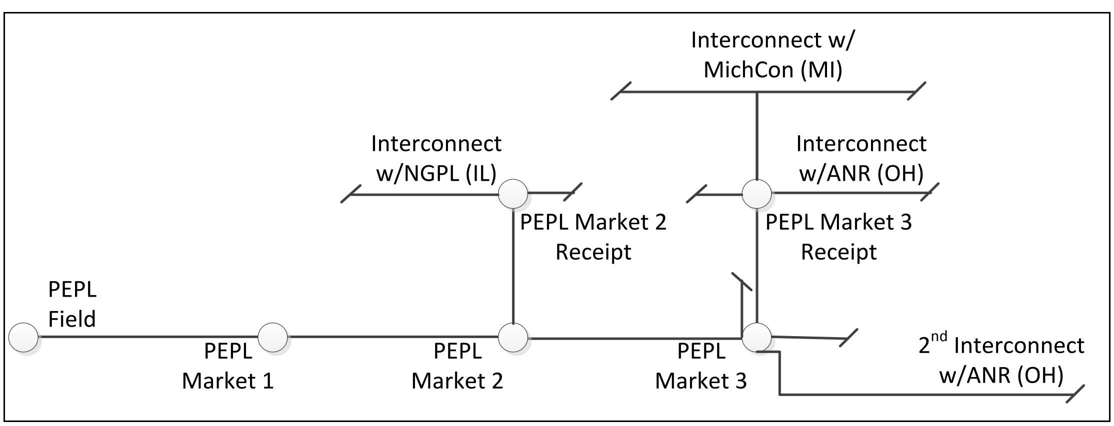


Figure 31 Partial representation of Panhandle Eastern Pipeline system definition in PLEXOS

For reference, the following pipeline interconnections and segments are modeled in PLEXOS for the PEPL system:

- PEPL individual interconnections (and associated states) with ANR (OH), Col Gas (OH), E Ohio Gas (OH), Enogex (OK), KMI EN (KS), MichCon (MI), NGPL (IL), Nisource (IN), NNG (KS), ONG (OK), Sstar (KS), TW (TX), Union Gas (MI) and Trunkline (IL)

- PEPL individual pipeline segments include:
    - Field to Market 1
    - Market 1 to Market 2
    - Market 2 to Market 3
    - Market 2 Receipt to Market 2
    - Market 3 Receipt to Market 3
    - Market 3 to Export
    - Import to Market 3

PEPL's actual system map is provided in Figure 32.

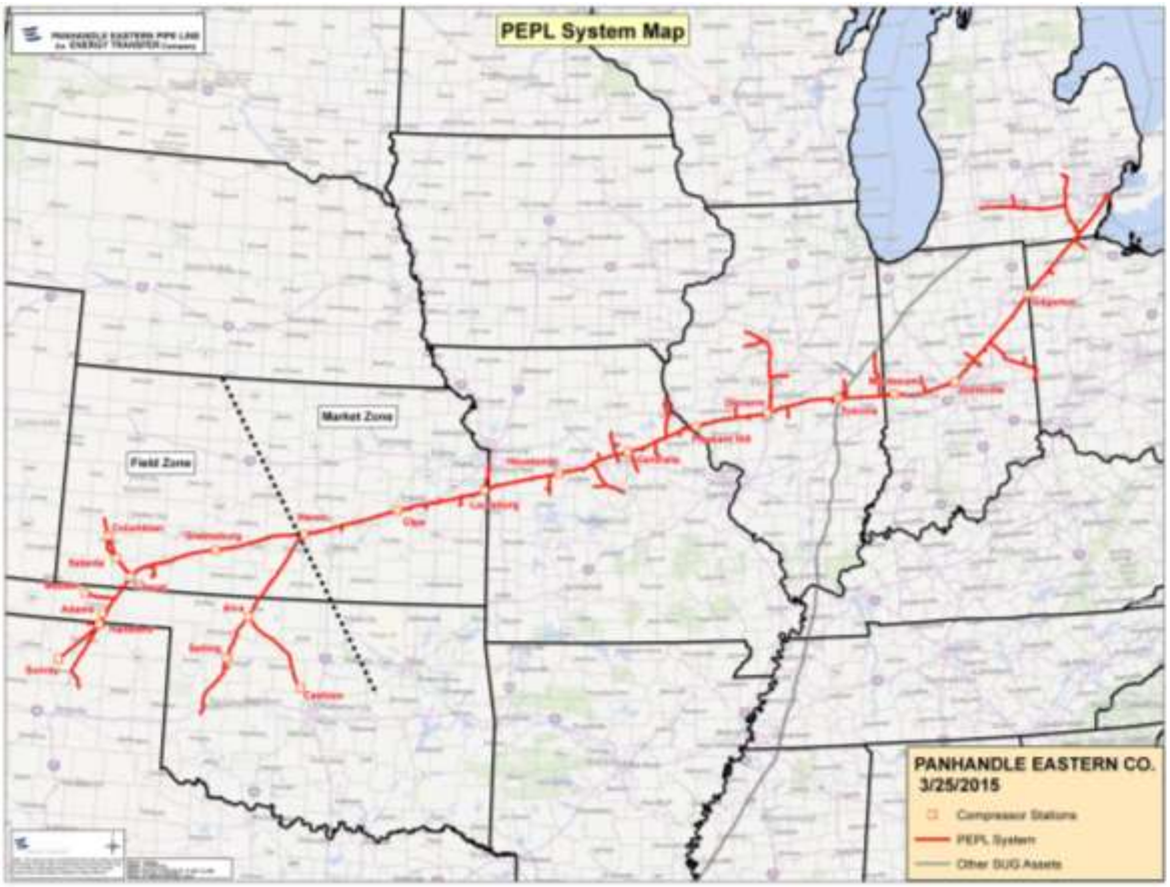


Figure 32 PEPL System (Source: Energy Transfer, 2015)

Pipeline production properties defined in PLEXOS include:

- Flow charge ($/MMBtu): the incremental cost of extracting gas from the pipeline, charged against the flow in each user-defined interval (e.g. hour or day)
    - The total cost of this charge is reported as production cost for a given pipeline.

  - Flow charge is not defined by the vendor in the current iteration of the model. For further discussion of the impacts of this modeling assumption, as well as future plans for consideration of the flow charge variable, see Section 6.7.
- Initial volume (MMcf): the volume of gas in the pipeline at the start of the simulation
- Min/max volume (MMcf): lower and upper limits on the volume of gas that can be stored in the pipeline
  - This metric can be used to represent pipeline linepack.
- Max flow (MMcf): the maximum quantity of gas that can be extracted from the pipeline (as a rate)
  - This includes gas flowing through the pipeline as well as gas taken from storage in the pipeline, i.e. it puts an upper limit on the flow of gas.
  - The max flow property could be used to model de-rates for maintenance or outages, for example.
  - As like other time interval properties, the user can customize the interval, e.g. hour, day, week.

The following production properties, though not defined in the current version of the model, can also be specified by the user:

- **Flow charge back** ($/MMBtu): the incremental cost of extracting gas at the pipeline sending node, charged against the flow backward in each user-defined interval
  - The total cost of this charge is reported as production cost for a given pipeline.
  - This charge can only be applied to bi-directional pipelines.
- **Volume imbalance** (MMcf): the absolute value of the difference between delivery volume into the pipeline and the redelivered volume off the pipeline (i.e. Volume Imbalance = end volume – initial volume)
- **Imbalance charge** ($/MMBtu): the charge applied to the volume imbalance

In addition to pipeline production properties, capacity and expansion properties[25] can be defined by the user. The vendor's definition of the natural gas pipeline system will be used for MISO's CPP study. As mentioned previously in this document, the vendor definition of the natural gas pipeline system is based on that used for the EIPC gas-electric study. For specifics on the definition of pipeline characteristics in the EIPC study, see Exhibit 7 of Target 2 of the study report[26].

6.3 Gas Nodes

Gas nodes serve as the interconnectors of gas infrastructure elements in the model, as well as the tie point between gas-fired electric generators and gas pipelines. Nodes can be defined by assigning them properties, such as a constraint on the max flow through the node.

Currently, gas node property definitions from the vendor do not include max flow day; MISO will use this definition, allowing interconnects to set flow constraints rather than nodes in the model.

[25] For a list of gas pipeline capacity properties, as defined by Energy Exemplar, see Appendix D. Expansion properties will not be addressed in this document, given its focus on the production cost functionality of PLEXOS.
[26] See http://www.eipconline.com/uploads/Exhibit_7_GPCM_13Q4base_Database.pdf

6.4 Gas Demand (Non-Power)

Residential, commercial, industrial and transportation gas demand is currently modeled in PLEXOS with individual state-level demand profiles (RCIT aggregate demand profile for each state). Each profile contains a value for each hour of the year, based on historical demand. State-level residential, commercial and industrial (RCI) gas demand will be distributed amongst gas nodes within the state, per LDC gas demand forecasts, as gathered for the EIPC gas-electric study (see Exhibit 15 of the Target 2 study report[27] for LDC forecast source documentation). The LDC forecasts will determine the nodal distribution factors in the CPP study model; the shape of the hourly profile of the demand from the vendor will be normalized and retained; the shape will then be applied to proprietary demand forecasts from IHS CERA[28] to produce an 8760-hourly profile.

Canadian and Mexican gas imports/exports will not be modeled in the CPP study, with the exception of liquefied natural gas (LNG) exports. LNG exports will be represented with state-level profiles, again based on IHS CERA proprietary forecasts.

The demand shortage price is assumed by the vendor to be $100/MMBtu; this value will be retained for the CPP study.

6.5 Gas Demand (Electric Power)

Gas-fired electric generators are interconnected with gas infrastructure in the model via gas nodes; they are likewise interconnected with electric infrastructure via an electric bus. In the current iteration of the model, generators with multiple real-world interconnections to natural gas infrastructure are represented with a single pipeline interconnect (arbitrarily selected amongst the interconnections) in the model. The mapping of gas-fired generators to gas pipelines in the model is based on data collected via the EIPC study[29].

6.6 Gas Storage

Gas storage fields are also represented in the PLEXOS gas model, tied to gas pipelines via gas nodes, and defined by the following key properties:

- **Initial volume** (MMcf): the volume of gas in the storage field at the start of the simulation
- **Min/max volume** (MMcf): the min/max volume of gas allowed in storage
    - "Working gas" is the difference between the max volume and the min volume
- **Max withdrawal/injection** (MMcf): the maximum volume that can be withdrawn from/injected into storage in a given interval, e.g. daily or hourly
- **Withdrawal/injection charge** ($/MMBtu): the incremental cost to withdraw gas from/inject gas into storage
    - Can be defined as a curve or in bands, e.g. increasing costs as field is depleted
- **Target** (MMcf): sets the storage volume for the end of the interval
    - An associated **target penalty** ($/MMBtu) can also be set for violating the target, to drive storage utilization trends in the model.

[27] See http://www.eipconline.com/uploads/Exhibit_15_LDCs_Gas_Demand_Forecasts.pdf
[28] The CERA forecast is a 20-year projection (single daily demand value per month) per state.
[29] See Appendices 1 through 6 at http://www.eipconline.com/Gas-Electric_Documents.html for generator-to-pipeline mapping.

- **Max ramp** (MMcf): the maximum allowed rate of change in storage end volume between one dispatch interval and the next

In the current version of the model, there are hundreds of storage field objects[30]. For these fields, the vendor has included definition of initial storage levels (for January and May), max volume and max withdrawals. These values are based on the EIPC study dataset (see Table E7-5 in Exhibit 7. GPCM 13Q4base Database[31]) and they will be retained for the CPP study.

The generic withdrawal charge as set by the vendor for state-level gas storage is equal to 10% of the cost to produce gas in a given state. Injection charges are not currently modeled in PLEXOS. For the CPP study, MISO will replace the state-level values for the cost to produce gas with forecasted values for individual gas basins (which will be applied to nearby pooling points per pipeline, as described in Section 6.1). MISO proposes to retain the 10% storage charge-to-production cost assumption, using the forecasted production cost values for the CPP study but welcomes feedback on more appropriate methods of modeling gas storage charges in future applications of the PLEXOS model.

Storage injections and withdrawals are not modeled as profiles; rather, the model will consider storage withdrawal/injection as it makes dispatch decisions.

6.7 Future Developments

The PLEXOS gas model is continually evolving. Planned and potential improvements (and approximate timelines) include representation of the following:

- **Multiple interconnections between gas-fired generators and gas pipelines** (near-term)
  - In the current version of the gas model, gas-fired electric generators that are interconnected with multiple pipelines are represented with a single interconnection, arbitrarily selected amongst the multiple interconnects.
  - Future versions of the model will attempt to reflect multiple interconnects.

- **Gas storage tariffs** (mid-term)
  - Currently, modeled storage withdrawal/injection rates do not reflect cost differentials across gas storage fields; future versions of PLEXOS may include customized representation of storage costs, such as deliverability, capacity and withdrawal/injection charges.

- **Gas pipeline tariffs** (mid-term)
  - In the current version of the model, fuel transportation contracts are not captured, i.e. regardless of the contract arrangements made in the real world, each gas-fired generator in the model has the same access to the pipeline capacity with which it is interconnected. Essentially all gas-fired generators have interruptible transportation service in this version of the model.
  - More specifically, there is no gas transport cost (captured via the flow charge property on individual pipelines or pipeline segments) reflected in the model. Thus, the order of dispatch of gas-fired electric generators in the model is driven by 1) the cost to supply gas at a given pooling point, 2) the economic and physical characteristics of generators

[30] See Appendix E for a list of the individual gas storage fields defined in the PLEXOS model.
[31] See http://www.eipconline.com/uploads/Exhibit_7_GPCM_13Q4base_Database.pdf for definition of individual storage properties (capacity, MDth; max injection rate, MDth/d; max withdrawal rate, MDth/d).

and 3) the physical constraints on the pipeline network and the electric transmission system.

- MISO notes the significant role the difference in the cost of transport from one region to another (i.e. basis) plays in the real world dispatch of gas-fired generators. Future iterations of the model will attempt to reflect transport cost variations from one pipeline to the next, by assigning pipeline tariff rates as transport costs via the Flow Charge property to each pipeline segment modeled.
- Likewise, LDC contracts to serve RCI load are not captured in the current version of the model; however, because RCI demand is modeled with a demand profile, it is essentially equivalent to firm service and reduces the amount of pipeline capacity available for gas-fired electric generators.

- **Local Distribution Companies (LDCs)** (mid-term)
  - RCI demand behind the LDC city gate is currently represented as part of a state-wide demand profile that is then distributed across gas nodes in the state per LDC demand forecasts. This demand will require access to pipeline capacity on an hourly basis at a level corresponding to the level of hourly demand. The remainder of the pipeline capacity is available to serve electric demand for gas. The underlying assumption of this representation of RCI demand is that LDCs will release contractual capacity not needed to serve load and that electric generators will have access to this capacity, on an hourly basis. While this is a simplified representation of real world allocation of unused capacity, it is a reasonable assumption for this stage of the model.
  - Electric power demand from gas-fired generators behind LDC city gates is currently represented in the same manner as electric power demand with direct interconnects. This is to say that regardless of whether the generator behind the city gate has a firm contract with an LDC, it is still modeled on par with generators that are directly interconnected with the interstate pipeline system.
  - Future versions of the model may more closely represent LDC load, including electric generation. This aspect of the model is still under development.

Other potential areas for future model development include:

- **Customized gas demand shortage penalty price**
  - There is currently a placeholder penalty for unserved gas demand (represented as "gas demand shortage" in the objective function) in the model of $100/MMBtu; absent an industry standard or explicit market indicator for the value of lost gas load, this figure will serve as a generic approximation for the whole of the Eastern Interconnect.

- **Priority order for pipeline access/generator dispatch**
  - Each gas-fired generator in the current version of the model is mapped to a single pipeline (future versions will account for multiple interconnects).
  - Each individual pipeline is represented as interconnected pipeline segments, based on tariff-defined major production and market zones, tied together via gas nodes.
  - At this level of granularity, there may be multiple gas-fired generators connected via the same node to a given segment of pipe. For existing gas-fired generators, individual generator characteristics (i.e. heat rate) will dictate which of the similarly mapped gens would be dispatched first.

- For new, generic (all with the same characteristics and costs) combined cycle and combustion turbines in the model mapped to the same node, the first listed will be dispatched.
- In future versions of the model, the type of contract a given generator holds may be the deciding factor for which unit/s gets dispatched amongst several generators mapped to the same gas node.

MISO welcomes stakeholder input on the current representation of gas infrastructure in the PLEXOS model, as well as on planned and potential model developments.

6.8 Co-optimization

The production cost module of PLEXOS performs chronological, security-constrained unit commitment and economic dispatch. The integration of the PLEXOS gas model, described in the preceding sections, with the PLEXOS electric model allows for co-optimized gas-electric dispatch. This means that the model considers both gas and electric infrastructure characteristics and constraints when formulating the dispatch stack.

The objective function for gas-electric production cost modeling in PLEXOS can be expressed as the minimization of the cost to serve gas and electric load, subject to a number of constraints, or

Minimize:

$$\sum [PCe + PCg + DSe + DSg + ASc]$$

Equation 2 PLEXOS Objective Function

Subject to:

Electric transmission constraints
Pipeline constraints (design capacity)
Feasible gas production
Feasible electric generation and feasible ancillary services provision (per generator)
Electric generation = Electric demand + Electric losses – Unserved electric load
Gas production = Gas demand + Gas generation demand – Unserved gas load
Ancillary service provision ≥ Ancillary Services Requirements (for the pool)

Where:

PCe = electric production cost
PCg = gas production cost
ASc = ancillary services cost
DSe = electric demand shortage cost
DSg = gas demand shortage cost

The definition of gas production cost in the equation above is the volume of gas produced at the field multiplied by the short run marginal cost of production. The gas demand shortage cost is defined as the cost of unserved demand on the gas system. The gas production cost and gas demand shortage cost are simultaneously considered with the electric production cost and electric demand shortage cost, as well as with the cost of providing ancillary services, in the optimization.

6.9 Outputs

The user can select the desired outputs of the production cost simulation from 1,000's of output parameters. Each individual parameter can be reported for a given period (time interval) and/or as a summary for the entirety of the simulation. Figure 33 shows the outputs of gas-electric co-optimization at a high level.

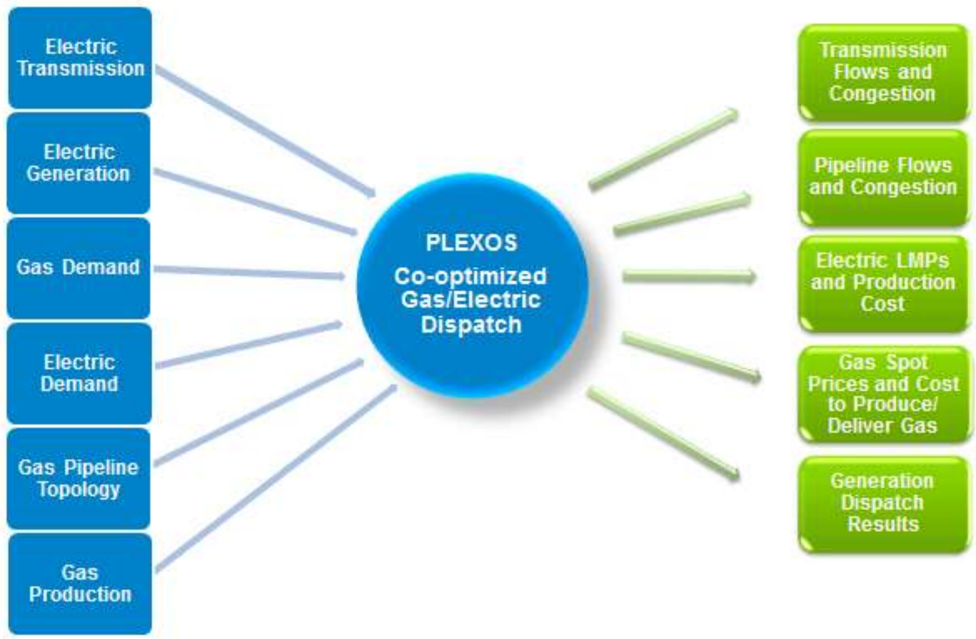


Figure 33 High-level inputs and outputs for optimized gas-electric dispatch in PLEXOS

The outputs of the gas side of the model can be grouped into two main buckets:

- **Physical (congestion) metrics:** quantification of the utilization of capacity at each gas node/for each pipeline segment, in every interval of the simulation; in other words, the duration, location & magnitude of pipeline congestion
  - For comparison, the electric side outputs of the model include line flows and binding hours.

- **Economic (cost/price) metrics:** quantification of the cost to produce and transport gas; gas spot prices are provided at each gas node for every interval of the simulation
  - For comparison, the electric side outputs of the model include locational marginal prices (LMPs).

In combination, the physical and economic metrics should allow for identification of candidate areas for natural gas infrastructure expansion. While much of the MISO stakeholder body is familiar with the representation of electric transmission system congestion, the characterization of congestion on the gas network is new territory for both MISO and the majority of its stakeholders. The determination of indicative gas infrastructure needs in the context of the CPP will be a collaborative effort, amongst MISO, its stakeholders, including gas industry representation.

7 Reliability Analysis Methodology

The reliability assessment uses the MTEP15 2020 and 2025 summer peak and shoulder load models. The transmission system is analyzed by applying North American Electric Reliability Corporation (NERC) transmission planning (TPL-001-4) standards and Transmission Owner's planning criteria, to identify reliability violations caused by potential re-dispatches, retirements, and capacity expansion units under different scenarios described in Section 5. Capacity expansion units are added without transmission upgrade assumptions and are located at high voltage busses to avoid outlet issues. Generation dispatch in the powerflow models is updated according to the security-constrained economic dispatch (SCED) to dispatch generation to within transmission limits.

Study approach:

- Steady-state thermal and voltage analyses are performed.
- Study region includes the MISO region as well as first-tier areas (PJM, SPP, TVA, AECI, SOCO, MRO) in the EI.
- Contingencies include a set of planning events within MISO consistent with those required under TPL-001-4.
- Monitored Facilities include all 69 kV and above facilities within MISO and the first-tier areas identified above.
- Reliability analysis is performed with and without the CPP constraints.

The results of the reliability assessment include thermal and voltage violations. The following characteristics define these violations:

- **Thermal violations** – violations of facility limits with an incremental change of 1% in thermal overloads
- **Voltage violations** – violations of voltage criteria with an additional decline in area voltage by 1%

8 Base Dataset

This section describes the preparation of and assumptions for the model that underlies each of the scenarios in the Phase III study. Some of the data presented is not directly incorporated in the Phase III study models but is included for information on the creation of the base dataset.

The base dataset for this study is the MTEP15 BAU economic study model. The BAU future captures current policies and trends and assumes a continuation of the status quo throughout the duration of the study period. All applicable[32] EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted into MISO's Module E Capacity Tracking (MECT) tool[33]. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. To capture the expected effects of environmental regulations (primarily the Mercury and Air Toxics Standards) on the coal fleet, 12.6 GW of coal unit retirements are modeled. These assumptions were developed in consultation with stakeholders via MISO's Planning Advisory Committee and approved by a stakeholder vote in early 2014. All other scenarios for this study are variations of this underlying dataset.

8.1 Baseline Generation Expansion

The Generation Interconnection Queue is the primary source for out-year capacity; however, the queue is generally limited to five years out or less for new capacity. For this reason, a capacity expansion tool is used to supplement the out years to maintain the load-to-resource balance and Planning Reserve Margin (PRM) target. The Electric Generation Expansion Analysis System (EGEAS), created by the Electric Power Research Institute (EPRI), is the capacity expansion software tool used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. To use Regional Resource Forecast (RRF) units[34] in a production cost model, they must be sited at buses in the powerflow model. Units are sited based on stakeholder-vetted rules and criteria.

The objective function of EGEAS study aims to minimize the 20-year capital and production costs, with a reserve margin requirement indicating when and what type of resources will be added to the system. The following sections focus on data assumptions and methodologies specific to EGEAS applications. This baseline generation forecast is used for the BAU scenario and all other scenarios are built off of this. Figure 34 details the location and fuel type for these units.

[32] The BAU model excludes the Clean Power Plan.
[33] For details on the type of information collected through the MECT, see https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/300%20Level%20Training/Level%20300%20-%20Module%20E%20Capacity%20Tracking%20Tool.pdf.
[34] See Section 9 for additional details on RRFs.

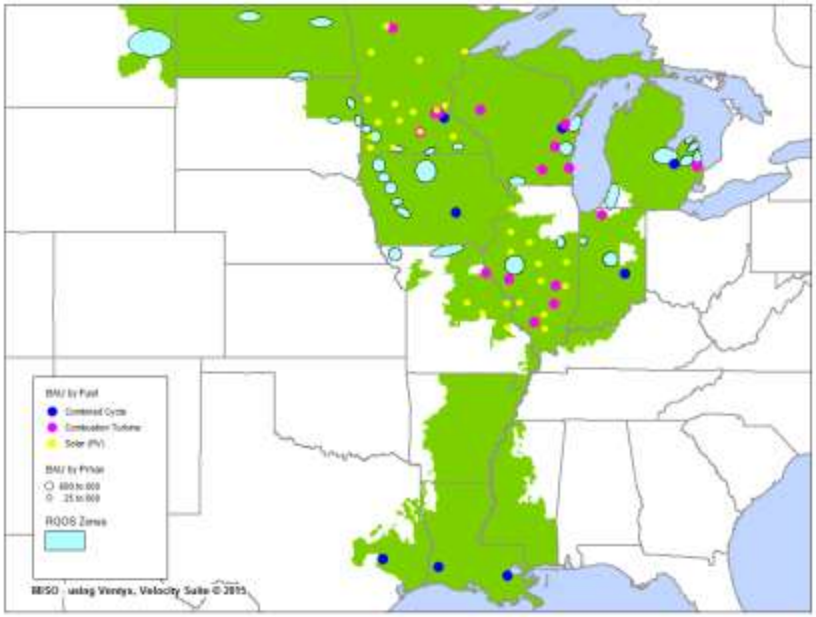


Figure 34 MTEP15 BAU Capacity Expansion

8.2 Baseline Resource Mix

The baseline resource mix per study region is shown in Table 8 and the pie charts in Figure 35 through Figure 41. The baseline resource mix as defined for this study is the nameplate capacity (in MW) for all existing, under construction and planned units.

Region	Coal	Nuclear	Gas	Wind	Solar	Hydro	Pumped Storage	Oil	Other
MRO	4,555	0	2,781	1,470	0	3,408	0	190	64
MISO	73,537	14,953	72,724	16,032	76	2,133	2,518	4,200	1,363
NYISO	1,963	5,289	21,406	1,919	12	4,876	1,407	4,717	1,378
PJM	76,011	36,308	70,607	7,932	714	2,844	5,610	10,285	2,637
SERC	41,063	21,930	49,014	255	388	6,477	4,626	2,411	783
SPP	24,421	2,449	28,777	9,878	95	2,396	474	1,147	42
TVA*	23,710	8,077	20,556	1,985	22	5,371	1,856	59	5

Table 8 Existing, Under Construction and Planned Units

*For EGEAS analysis, Associated Electric Cooperative Inc. (AECI), Louisville Gas & Electric and Kentucky Utilities are combined with the Tennessee Valley Authority (TVA)

Figure 35 through Figure 41 show the resource mix breakdowns as a percentage of total generation capacity for each modeled Eastern Interconnect region.

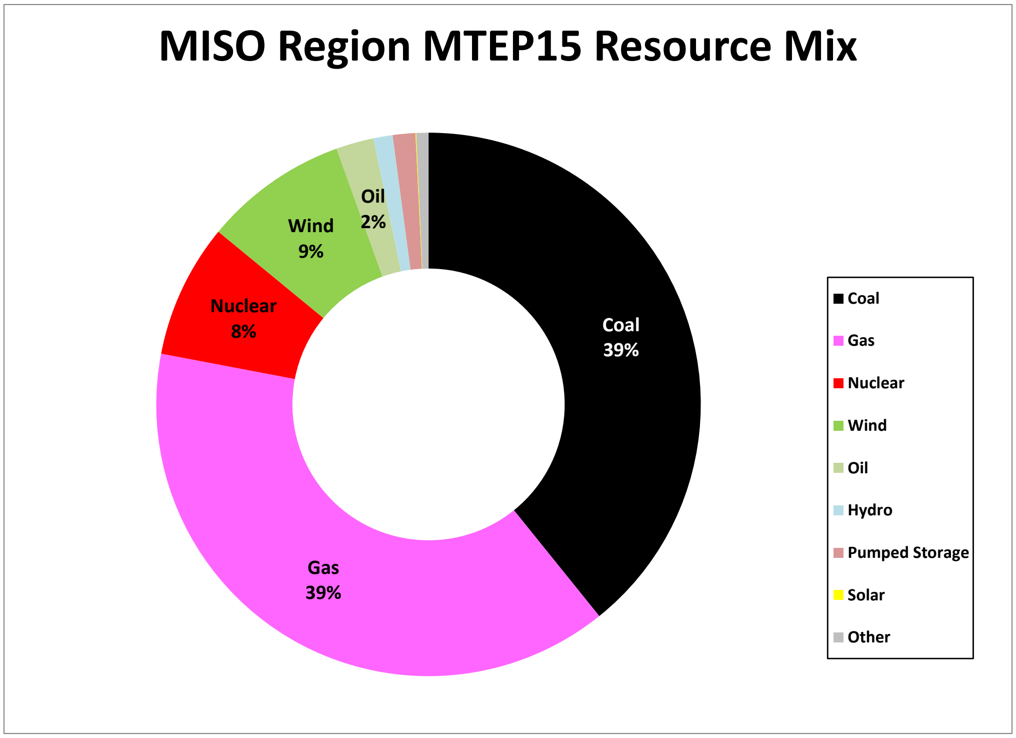


Figure 35 MISO Resource Mix

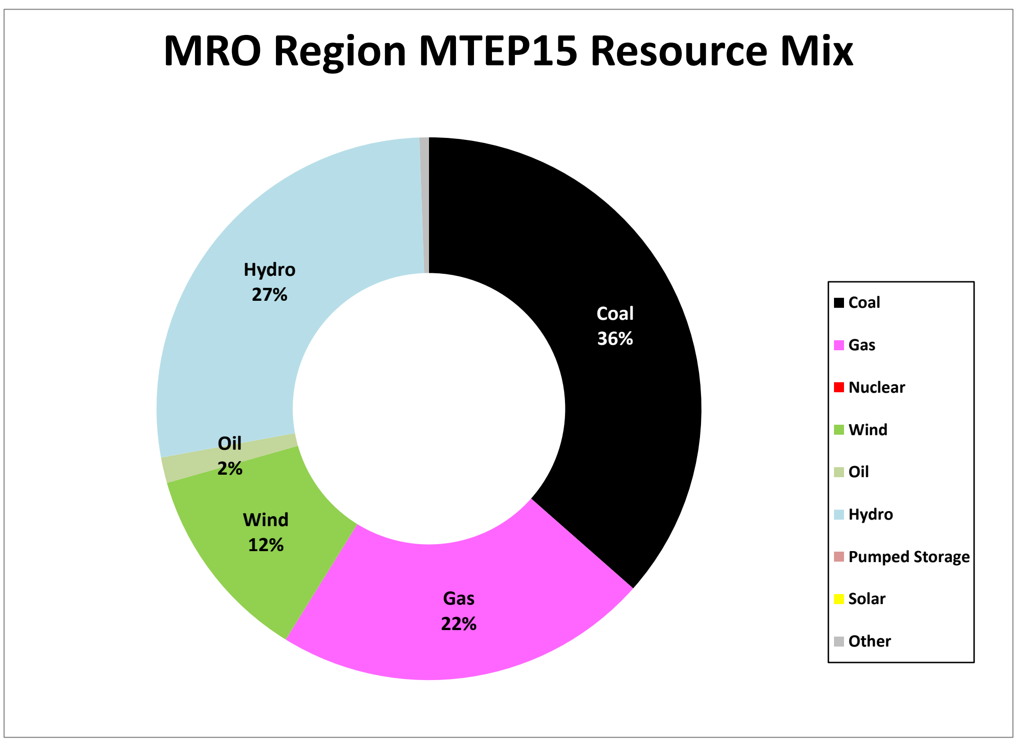


Figure 36 MRO Resource Mix

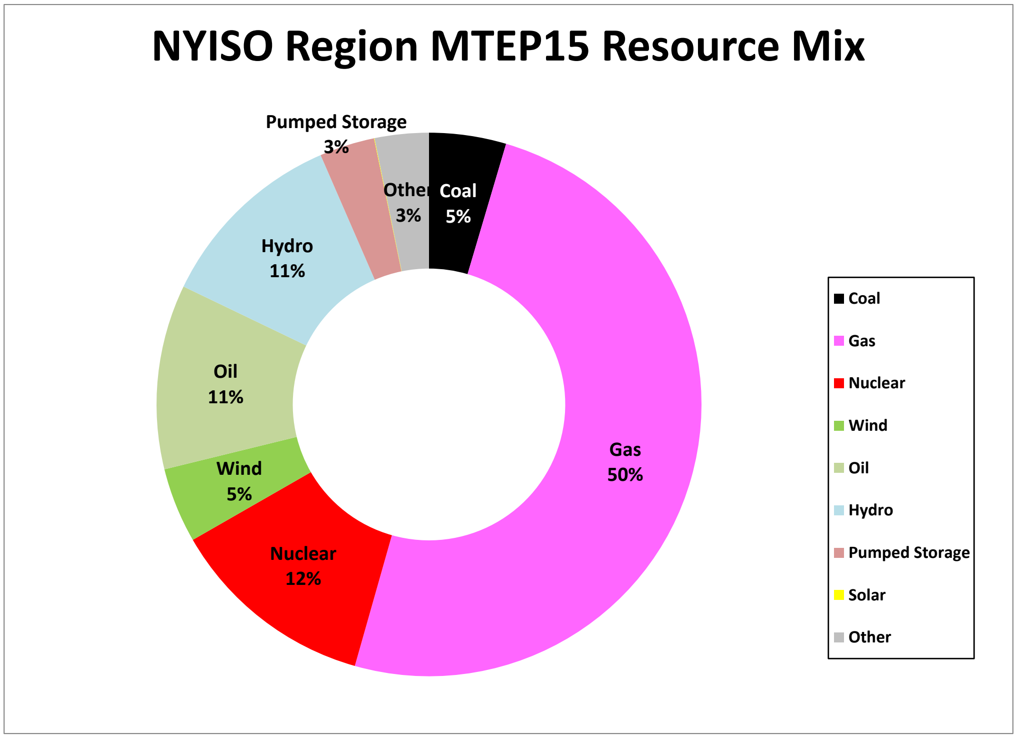


Figure 37 NYISO Resource Mix

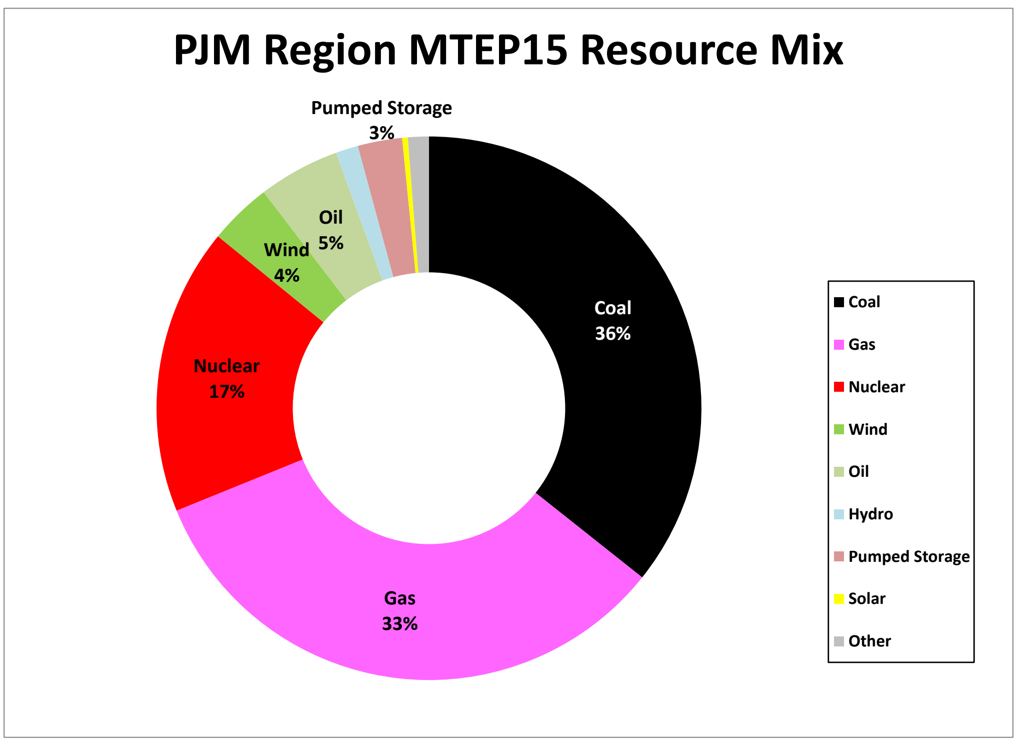


Figure 38 PJM Resource Mix

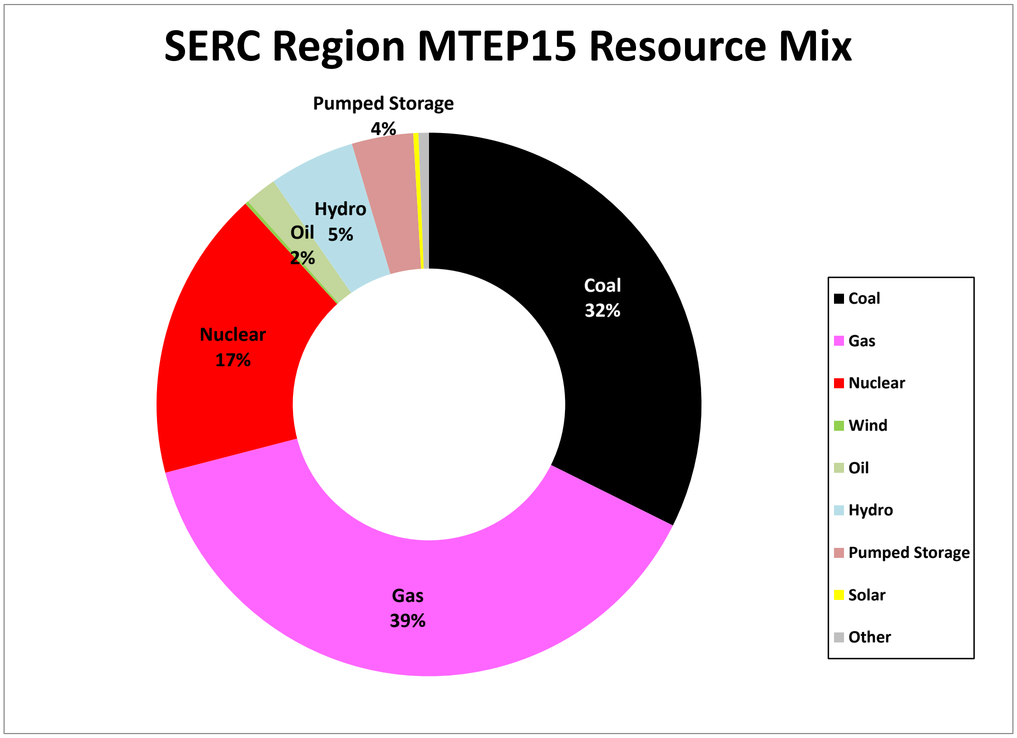


Figure 39 SERC Resource Mix

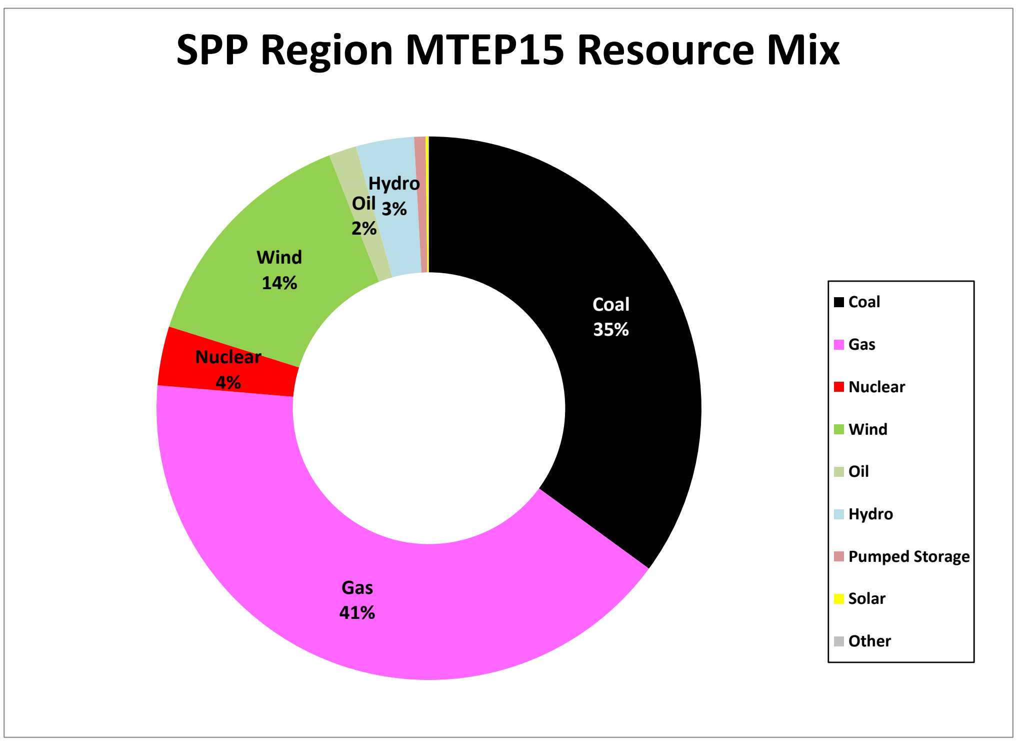


Figure 40 SPP Resource Mix

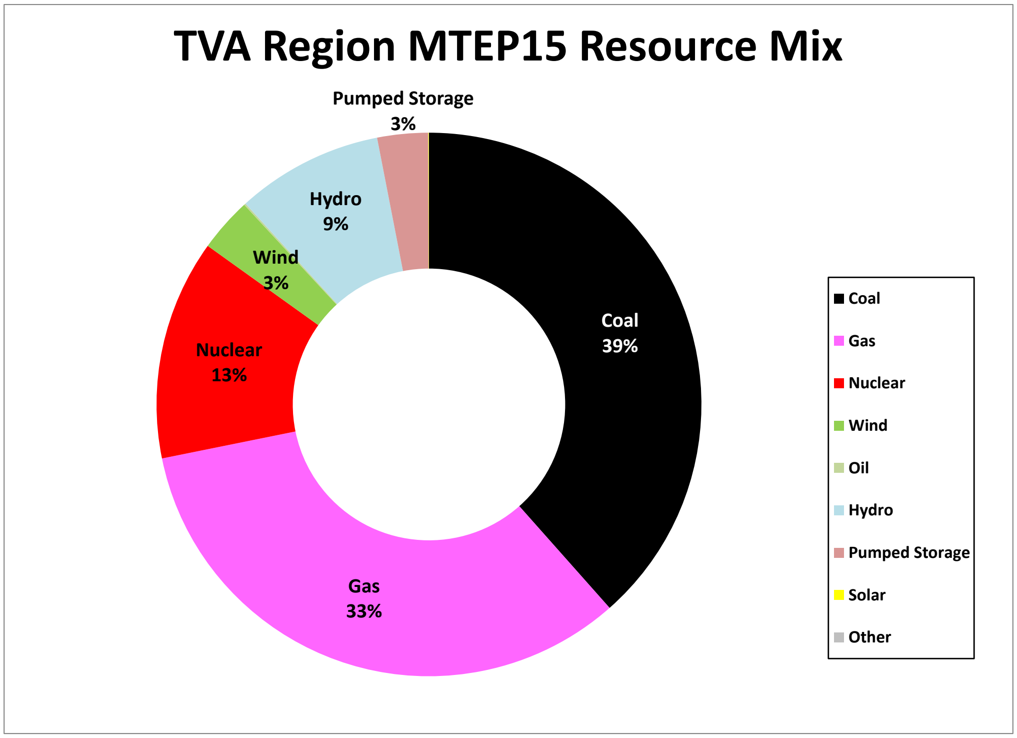


Figure 41 TVA Resource Mix

8.3 Regional Demand and Energy Forecasts

In PLEXOS, projected future demand and energy growth rates are input at the company level. The MISO baseline value for the demand growth rate is derived from the Module E 50/50 load forecast growth rate (0.8 percent). Low and high values, for both demand and energy, are established by going 1.3 standard deviations above and below the baseline. By utilizing the Load Forecast Uncertainty (LFU) metric, there is an 80% probability that the demand and energy forecast will fall within the high and low growth rates of 0.14% to 1.5%.The effective demand and energy growth rates for each region are calculated after the EGEAS capacity expansion analysis, taking only state-level Demand Side Management (DSM) mandate and goal projections into consideration. The effective growth rates are ultimately used in PLEXOS (seen in

Region	BAU	
	Demand (%)	Energy (%)
MISO	0.75	0.76
MHEB	1.08	1.02
MRO	1.80	1.88
NYISO	-0.26	-0.53
PJM	0.60	0.80
SERC	1.26	1.19
SPP	1.03	1.25
TVA	0.83	0.71

Table 9).

Region	BAU	
	Demand (%)	Energy (%)
MISO	0.75	0.76
MHEB	1.08	1.02
MRO	1.80	1.88
NYISO	-0.26	-0.53
PJM	0.60	0.80
SERC	1.26	1.19
SPP	1.03	1.25
TVA	0.83	0.71

Table 9 Effective Demand & Energy Growth Rates (2013-2028)

8.4 Fuel Forecasts

All of the fuel forecasts are developed in PowerBase using a pointer system. A pointer system works by designating one fuel as the fuel index and then all other fuel forecasts are based on this fuel index, with some adjustment (usually due to transportation costs) from the index value. In the MTEP database, all natural gas-fired generators point to the Henry Hub natural gas forecast. Therefore, all references to natural gas in the futures matrix are in terms of the Henry Hub forecast.

The baseline natural gas forecast used for MTEP15 was developed by Bentek as part of the MISO-commissioned Phase III Natural Gas Infrastructure Analysis[35]. High and low forecasts were developed by adding or subtracting 20 percent from the baseline. Since Bentek assumed an inflation rate of approximately 3.5 percent in their forecast, it was necessary to remove this inflation rate and to use the inflation rates for the BAU future scenario that was selected in the Futures development process. The resulting MTEP15 natural gas forecasts are in nominal dollars per MMBtu (Figure 42).

[35] Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis – An Analysis of Pipeline Capacity Availability. Table 5-4.

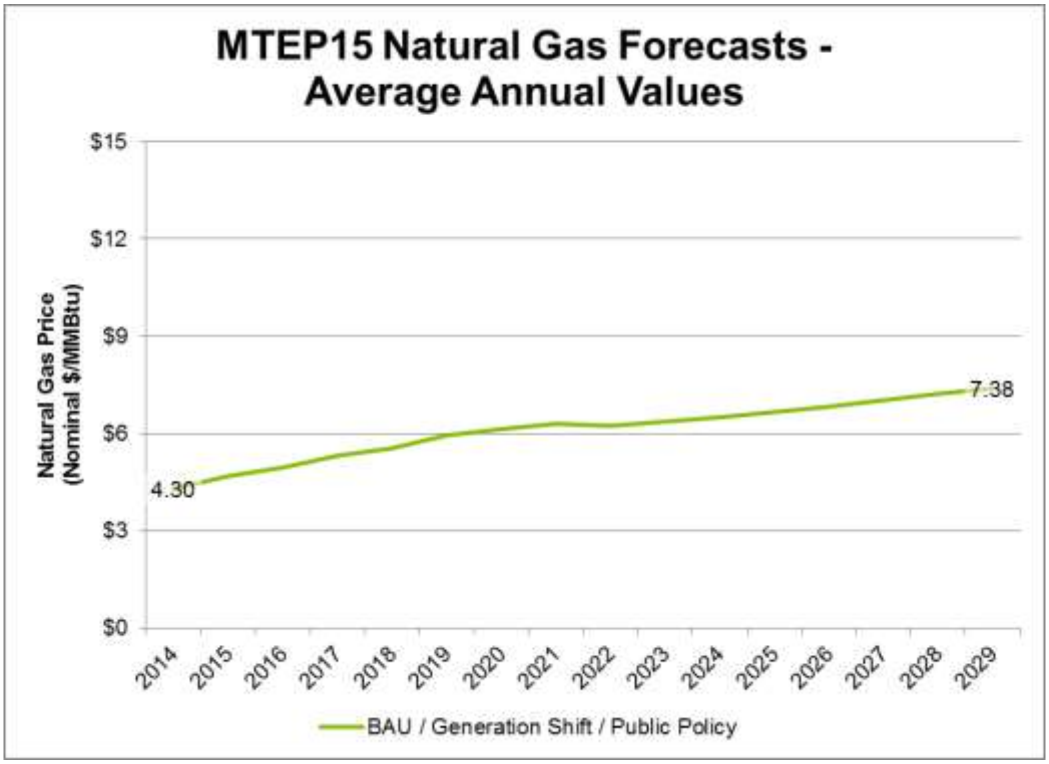


Figure 42 Natural Gas Price Forecast

8.5 Study Areas

The MTEP15 database is comprised of all areas in the Eastern Interconnect (Figure 43), with the exception of Florida, ISO New England and Eastern Canada:

- Midwest Reliability Organization (MRO)
- Midcontinent Independent System Operator (MISO)
- New York Independent System Operator (NYISO)
- PJM Interconnection (PJM)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Tennessee Valley Authority (TVA)

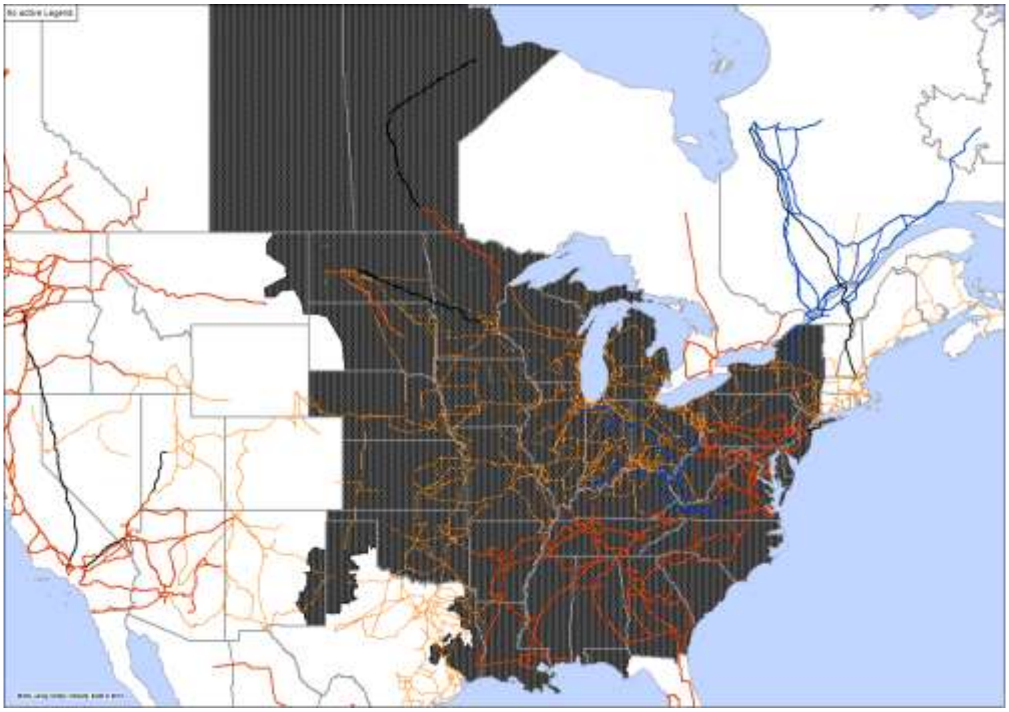


Figure 43 Study Footprint

8.6 Capacity Types

Generation capacity is categorized into existing, under construction and planned units. Assumptions related to each of these categories include the following:

- Existing: Operating license extensions are assumed on all nuclear units
- Under Construction: Units with steel in the ground, but not yet under commercial operation
- Planned: All capacity resources with a signed Generator Interconnection Agreement (GIA)

8.7 Firm Interchange

Firm interchange contributes to resource adequacy by reducing a region's overall internal capacity needs over time. It is assumed that each modeled region will build generation capacity to meet its own resource adequacy needs.

Based upon the 2015 Loss of Load Expectation (LOLE) External Ties Model, MISO assumes a net scheduled interchange of 3,157 MW. This capacity is held constant in all 20 years of the EGEAS modeling and is assumed to be available at the time of MISO peak. This is used for capacity forecasting when defining the base dataset used in PLEXOS.

In PLEXOS, net scheduled interchange between MISO and their first tier neighbors is scheduled dynamically using SCED and in consideration of hurdle rates. Scheduled interchange with regions that are not modeled in PLEXOS is an hourly value that represents what the interchange would be with those regions.

8.8 Hurdle Rates

Hurdle rates influence the capability of a pool to obtain, support or sell energy to other pools. In order for a sale to occur, the difference in dispatch costs between the buying pool and the selling pool must be greater than the hurdle rate between them.

PLEXOS performs security constrained unit commitment and economic dispatch, with user-defined hurdle rates. The hurdle rate for the unit commitment step is called the commitment hurdle rate; likewise, the hurdle rate defined for the economic dispatch step is the dispatch hurdle rate.

Normally, users set the commitment hurdle rate to be greater than the dispatch hurdle rate. This causes a pool's units to be dispatched against its own pool load first, then allows pool interchange during the final dispatch via the dispatch hurdle rate.

Though there is no standard for defining hurdle rates, they are commonly based on the filed transmission through-and-out rates, plus a market inefficiency adder.

The dispatch hurdle rates between pools are shown in Table 10.

		TO:								
		PJM	MISO	TVA	MRO	SPP	SERC	MHEB	NYISO	TVAO*
FROM:	**PJM**	*	1 / 1	4.8 / 4.8	N/A	N/A	4.8 / 4.8	N/A	10 / 10	4.8 / 4.8
	MISO	8 / 8	*	7.5 / 5.4	5.5 / 3.4	7.5 / 5.4	8 / 8	0 / 0	N/A	7.4 / 5.4
	TVA	30 / 30	30 / 30	*	N/A	- / -	30 / 30	N/A	N/A	30 / 30
	MRO	N/A	6.3 / 5.7	N/A	*	6.9 / 6.9	N/A	6.5 / 4.5	N/A	
	SPP	N/A	5.1 / 5.1	5.1 / 5.1	5.1 / 5.1	*	N/A	N/A	N/A	5.1 / 5.1
	SERC	6.5 / 4.5	10 / 10	6.8 / 5.0	N/A	N/A	*	N/A	N/A	6.8 / 5.0
	MHEB	N/A	0 / 0	N/A	11.6 / 7.3	N/A	N/A	*	N/A	N/A
	NYISO	3 / 3	N/A	N/A	N/A	N/A	N/A	N/A	*	N/A
	TVAO*	6.5 / 4.5	8.3 / 8.3	8 / 8	N/A	8.3 / 8.3	8.4 / 5.7	N/A	N/A	*

Table 10 Dispatch Hurdle Rates

*TVAO = TVA Other

8.9 Planning Reserve Margin Targets

The Planning Reserve Margin (PRM) is entered into EGEAS for the first year of the simulation, and is assumed to remain constant throughout the entire 20-year study period. PRM targets are based on respective system co-incident peaks (MW), with the exception of SPP's, which is based on its non-coincident peak (MW). Table 11 presents the 2014 reserve margin, as well as the PRM target, for each region.

Region	2014 Reserve Margin (%)	PRM Target (%)
MISO	24.0	14.80
MRO	64.0	15.00
NYISO	25.6	16.00
PJM	19.2	15.60
SERC	31.5	15.00
SPP	20.3	13.60
TVA	34.4	15.00

Table 11 PRM Margins and Targets

8.10 Wind Hourly Profile and Capacity Credits

A majority of the wind in the MISO footprint is registered as Dispatchable Intermittent Resources, or DIR. Generators with this designation are able to bid into the day-ahead market using high-confidence wind forecast data. Given that this information is not available for future years, EGEAS models all wind as a non-dispatchable technology using actual historical wind data developed during the MISO Regional Generator Outlet Study (RGOS) and updated as part of the NREL Eastern Renewable Generation Integration Study (ERGIS). All the RGOS wind zone profiles within MISO are averaged to arrive at a single profile, which is used in the EGEAS capacity expansion analysis. Similarly, a single profile for each of the regions external to MISO is made by averaging all NREL wind sites within each respective region.

The wind capacity credit is the maximum capacity credit that a wind resource may receive if it meets all other obligations of Module E to be a capacity resource. This value, which is a percent of the maximum nameplate capacity of the unit, reflects the risk associated with reliance upon an intermittent resource, such as wind. The capacity factor is the actual annual energy output of the unit as a percentage of the total potential energy output (based on 8,760 hours in a year). The wind capacity credit is updated annually during the MISO Loss of Load Expectation (LOLE) analysis and, for the 2014 planning year, was calculated to be 14.1 percent. Table 12 shows the capacity factors applied to each region as input to the EGEAS model for MTEP15. In PLEXOS, however, all wind units are modeled individually with their own hourly profiles and are considered dispatchable.

Region	Annual Capacity Factor (%)
MISO	40
MRO	41
NYISO	40
PJM	37
SERC	43
SPP	43
TVA	36

Table 12 Wind Capacity Factors by Region

8.11 Reserve Contribution

Three specific assumptions were made with regard to reserve contribution:

- 14.1% of nameplate wind capacity is counted toward its reserve capacity contribution.
- 25% of nameplate solar capacity is counted toward its reserve capacity contribution.
- The summer de-rated capacity for conventional generation is counted toward its reserve capacity contribution.

8.12 Financial Variables

Variables associated with the financing of new generation projects are listed Table 13. Note that these are average values across the footprint. These financial variables are used in MTEP15 EGEAS simulations.

Variable	Rate (%)
Composite Tax Rate	39.00
Insurance Rate	0.50
Property Tax Rate	1.50
AFUDC* Rate	7.00

Table 13 Financial Variables

* Allowance for Funds Used During Construction

8.13 Load Shapes

The load shapes used in PLEXOS and their sources are presented in Table 14.

Load Shape	Description and Source
System	2006 hourly profiles from Ventyx
Wind	2006 hourly profiles developed by AWS TrueWind for EWITS, and updated as part of the NREL Eastern Renewable Generation Integration Study (ERGIS).
Solar	2006 hourly profile developed by NREL for the Eastern Renewable Generation Integration Study (ERGIS)

Table 14 Load Shape Descriptions and Sources

8.14 Alternative Generator Categories

Table 15 and Table 16list the generic categories of generators used when forecasting future units to meet the planning reserve margin requirements.

Supply Side Options
Biomass
Coal
Combined Cycle - with and without sequestration
Combustion Turbine
Compressed Air Energy Storage
Hydro
Integrated Gasification Combined Cycle (IGCC) - with and without sequestration
Nuclear
Pumped Hydro Storage
Solar
Wind - on-shore and off-shore

Table 15 Alternative Generator Categories - Supply-Side

Demand Side Options
Commercial & Industrial (C&I) Low Cost Energy Efficiency (EE) program
C&I Interruptible

Table 16 Demand-Side Management Alternatives

8.15 Alternative Generator Data

Table 17 shows the fixed operation and maintenance (O&M) cost, variable O&M cost, heat rate, lead time (inclusive timeframe for unit construction), maintenance hours, and forced outage rate (FOR) for the alternative supply-side generator categories used in MTEP15 regional resource forecasting. The capacity of each forecasted generic unit from each category is 1,200 MW, with the exception of wind at 300 MW and solar at 25 MW. Monetary values given in the table are in 2012 dollars.

Type	Fixed O&M	Variable O&M	Heat Rate	Lead Time	Maint-enance Duration	Forced Outage Rate
	$/kW-Yr	$/MWh	MMBtu/MWh	Years	Hours	%
Biomass	105.63	5.26	13.50	4	0	3.25
Coal	20.68	1.12	8.80	6	672	4.48
CC	10.13	1.59	6.43	3	336	5.11
CCS*	47.98	3.31	7.53	3	504	5.11
CT	8.7	2.46	9.75	2	168	5.93
Hydro	14.13	2.66	0.00	4	0	3.25
IGCC	55.05	6.66	8.70	6	672	5.11
IGCCS**	34.06	7.79	10.70	6	672	5.11
Nuclear	68.7	2.49	10.40	11	672	2.95
PV	21.75	5.00	0	2	0	0
Wind	24.27	5.27	0	2	0	0

Table 17 Alternative Generator Data

* Combined-Cycle with Sequestration
** Integrated Gasification Combined-Cycle with Sequestration

8.16 Baseline Renewable Portfolio Standards (RPS)

Many MISO states have existing RPS mandates and goals with various starting dates, growth rates and program terms. For the MTEP BAU, only the mandates are captured as the goals are not legally enforceable. These numbers were taken from the DSIRE website: www.dsireusa.org.

Incremental renewable energy required per the RPS mandates, beyond existing qualifying resources, is forced into the model. Most RPS mandates have an energy requirement and only from certain types of renewable resources (see DSIRE for more). The existing units in MISO have expected capacity factors either based on historical performance or fleet averages. This, along with the nameplate capacities, is used to project the energy produced by existing renewable resources. The difference between the energy produced by existing renewable resources in each state and the energy required by state mandates drives the amount of renewable resource capacity to be added to the BAU model. The exact capacity amount is back-calculated using the capacity factors for wind, as this is the most common renewable energy resource built.

The capacity expansion wind units are built in 300 MW increments. To the extent states have specific solar requirements, a 25 MW PV unit was used with the characteristics also outlined above. Wind is assumed to have a 40.16% capacity factor, and an 18.9% capacity factor for solar. These are not the values used to calculate contribution to peak and for purposes of meeting PRM, but are rather used for an energy-to-capacity conversion. The capacity values chosen are specific to accommodate the capacity required without going over the EGEAS limitation of 99 of any given type of unit. This limitation prevents us from getting to the exact MW value mandated by either existing RPS or the CPP. This means that if

299 MW are required, a 300 MW unit will be built, and if 301 MWs are required, two 300 MW units will be built.

8.17 MTEP15 Futures Matrix

The MTEP15 futures matrix is included as a reference. The highlighted values (Table 18) were used for building the MTEP15 BAU model, the base model for the Phase III study. The capital costs of expansion units were also calculated using these numbers, along with those listed in the MTEP16 matrix (shown in the following section) to create a range of potential resource capital costs under CPP compliance.

MTEP15 UNCERTAINTY VARIABLES				
Uncertainty	**Unit**	**Low (L)**	**Mid (M)**	**High (H)**
New Generation Capital Costs[1]				
Coal	($/KW)	2,247	2,996	3,745
CC	($/KW)	783	1,045	1,306
CT	($/KW)	518	690	863
Nuclear	($/KW)	4,235	5,647	7,058
Wind-Onshore	($/KW)	1,525	2,034	2,542
IGCC	($/KW)	2,898	3,864	4,830
IGCC w/ CCS	($/KW)	5,054	6,738	8,423
CC w/ CCS	($/KW)	1,604	2,139	2,674
Pumped Storage Hydro	($/KW)	4,050	5,400	6,750
Compressed Air Energy Storage	($/KW)	957	1,276	1,595
Photovoltaic	($/KW)	2,225	2,966	3,708
Biomass	($/KW)	3,151	4,201	5,251
Conventional Hydro	($/KW)	2,248	2,998	3,747
Wind-Offshore	($/KW)	4,771	6,362	7,952
Demand and Energy				
Demand Growth Rate[2]	%	0.14%	0.80%	1.50%
Energy Growth Rate[3]	%	0.14%	0.80%	1.50%
Demand Response Level[4]	%		State mandates only	State mandates and goals
Energy Efficiency Level[4]	%		State mandates only	State mandates and goals
Natural Gas				
Natural Gas[5]	($/MMBtu)	Bentek -20%	Bentek forecast from Phase III Gas Study	Bentek +20%
Fuel Prices (Starting Values)				
Oil	($/MMBtu)	Powerbase default -20%	Powerbase default[6]	Powerbase default + 20%
Coal	($/MMBtu)	Powerbase default -20%	Powerbase default[7]	Powerbase default + 20%
Uranium	($/MMBtu)	0.91	1.14	1.37
Fuel Prices (Escalation Rates)				
Oil	%	2.0	2.5	4.0
Coal	%	2.0	2.5	4.0
Uranium	%	2.0	2.5	4.0
Emissions Costs				
SO_2	($/ton)	0	0	500
NO_x	($/ton)	0	0	NO_x: 500 Seasonal NO_x: 1000
CO_2	($/ton)	0	10	50
Other Variables				
Inflation	%	2.0	2.5	4.0
Retirements	MW	12,600 MW	19,000 MW + 11,600 MW age-related retirements = 30,600 MW[8]	23 GW
Renewable Portfolio Standards	%	State mandates only	20% MISO-wide mandate Solar 5% of overall mandate	30% MISO-Wide Mandate Solar 10% of overall mandate

Table 18 MTEP15 Futures Matrix

Notes on uncertainty variables:

1 All costs are overnight construction costs in 2014 dollars; sourced from EIA and escalated according to the GDP Implicit Price Deflator; H and L values are 20% +/- from the M value
2 Mid value for demand growth rate is the Module-E 50/50 load forecast growth rate
3 Energy values are determined based on historical load factors for each Load-Serving Entity (LSE)
4 MTEP13 modeled state mandates and goals for DR & EE
5 Prices reflect the Henry Hub natural gas price
6 PowerBase default for oil is $19.39/MMBtu
7 PowerBase range for coal is $1 to $4, with an average value of $1.69/MMBtu
8 11,600 MW value is based on MTEP13 database

8.18 MTEP16 Futures Matrix

MTEP16 futures introduced several changes to the capital cost assumptions for new resources. For example, maturity curves were assigned to new wind and new photovoltaic units in MTEP16's CPP futures. Wind and solar capital costs are assumed to start at $1,750/kW in 2015. Solar is decreased 10% each year and wind is decreased by 1% each year until 2020. The values for other new units are highlighted in yellow in Table 19 followed by a graph of the maturity curves for wind and solar units (Figure 44).

MTEP16 UNCERTAINTY VARIABLES				
Uncertainty	**Unit**	**Low (L)**	**Mid (M)**	**High (H)**
New Generation Capital Costs[1]				
Coal	($/KW)	2,279	3,039	3,799
CC	($/KW)	795	1,060	1,324
CT	($/KW)	525	700	875
Nuclear	($/KW)	4,296	5,728	7,160
Wind-Onshore	($/KW)	1,750	2,063	2,579
IGCC	($/KW)	2,940	3,919	4,899
IGCC w/ CCS	($/KW)	5,126	6,835	8,544
CC w/ CCS	($/KW)	1,627	2,170	2,712
Pumped Storage Hydro	($/KW)	4,108	5,477	6,846
Compressed Air Energy Storage	($/KW)	971	1,295	1,618
Photovoltaic	($/KW)	1,750	3,009	5,014
Biomass	($/KW)	3,196	4,261	5,326
Conventional Hydro	($/KW)	2,281	3,041	3,801
Wind-Offshore	($/KW)	4,840	6,453	8,066

Table 19 MTEP16 Futures Matrix

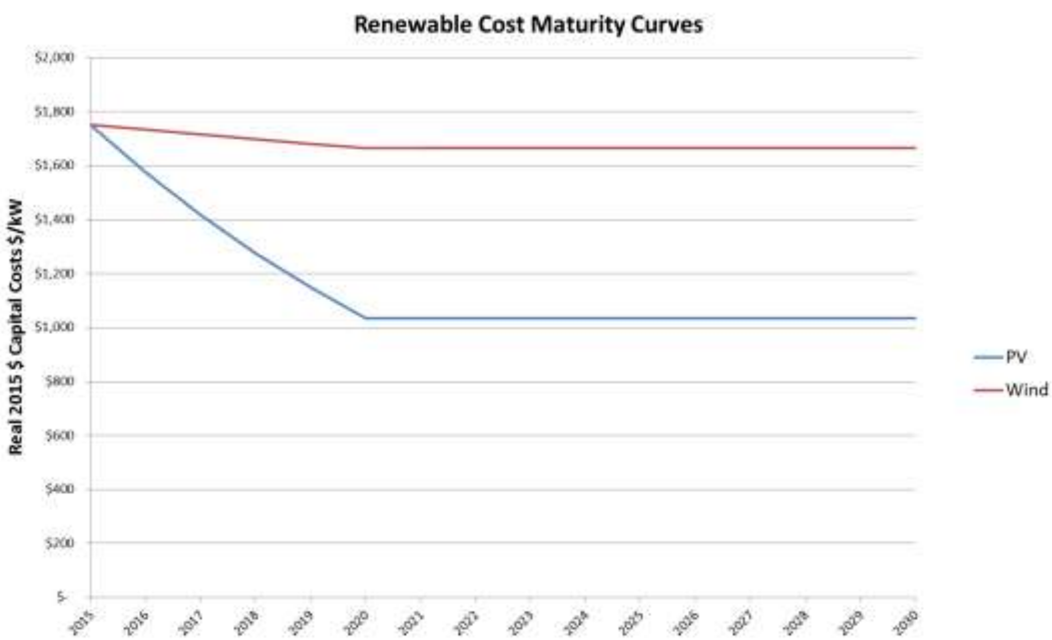


Figure 44 Renewable Cost Maturity Curves

**Prices are shown in nominal dollars and do not account for inflation.*

9 MTEP Unit Siting Methodology

Regional Resource Forecasted (RRF) units are an output of Step 1 of the MTEP 7-step process. Given that the generator interconnection queue is typically only useful for one to five years out for capacity, a capacity expansion tool, such as EGEAS, is used to supplement the out years to maintain the load-to-resource balance. These units must be sited within the powerflow model for use in PLEXOS. Beginning with MTEP11, MISO included Demand Response (DR) and Energy Efficiency (EE) units in the EGEAS capacity planning process. While EE is simply netted out of the baseline demand and energy values, DR units also have to be sited into the powerflow models for production cost analysis. Therefore, additional siting methodology for DR has been developed. A Geographic Information System (GIS) software program called MapInfo is used to assist in the generation siting. Siting rules, which are detailed below, are used to develop layers within the mapping software showing the potential locations of the resource forecasted units. The siting can be broken into three main categories. The categories are general siting rules, siting priority order and unit-specific greenfield siting. General siting rules apply to all scenarios.

9.1 General Siting Rules for EGEAS

The rules outlined in this section show, at a higher level, many of the underlying assumptions that go into the siting of RRF generation. These criteria could be referred to as the "first pass" siting criteria.

- Site by region, with the exception of wind.
- "Share the Pain" mentality. Not all generation in a region can be placed in one state and one state cannot be excluded from having generation sited.
- Avoid greenfield sites for gas units (CTs and CCs) if possible - prefer to use all brownfield sites.
- Site baseload units in 600 MW increments, except nuclear which is sited at 1,200 MW.
- Limit the total amount of expansion at an existing site to no more than an additional 2,400 MW.
- Restrict greenfield sites to a total size of 2,400 MW.
- Limit using queue generation without a signed Generator Interconnection Agreement (GIA) in multiple futures.
- Transmission is not an initial siting factor, but may be used as a weighting factor, all things being equal.

9.1.1 Generator Developmental Statuses

A generator's developmental status is required to determine how the unit will be treated in both the EGEAS capacity expansion model and the siting process. Existing and queue generation is given one of the following developmental statuses within the PowerBase database:

- "Active" – Existing, online generation including committed and uncommitted units. Does not include generation which has been mothballed or decommissioned.

- "Planned" - A generator that is not online, has a future in-service date, is not suspended or postponed and has proceeded to a point where construction is almost certain, such as it has a signed Interconnection Agreement (IA), all permits have been approved, all study work has been completed, state or administrative law judge has approved, etc. These units are used in the model to meet future demand requirements prior to the economic expansions.

- "Future" – Generators with a future online date that do not meet the criteria of the "planned" status. Generators with a future status are typically under one of the following categories, proposed, feasibility studies, permits applied, etc. These generators are not used in the models but are considered in the siting of future generation.

- "Canceled" – Generators that have been suspended, canceled, retired or mothballed. These units are not included in the EGEAS capacity expansion model, although their sites are often considered for brownfield locations in the siting process.

9.2 Site Selection Priority Order for EGEAS

- Priority 1: Generators with a "future" status
  - Queue generators without a signed Interconnection Agreement (IA)
  - The "New Entrants" Generators defined by Ventyx (noted as "EV" Gens)
  - Both Queue and EV Gens are under the following statuses:
    - Permitted
    - Feasibility
    - Proposed
- Priority 2: Brownfield sites (Coal, CT, CC, Nuclear Methodology)
- Priority 3: Retired/mothballed sites that have not been re-used
- Priority 4: Greenfield sites
  - Queue and "New Entrants" in canceled or postponed status
- Priority 5: Greenfield sites
  - Greenfield siting methodology

9.3 Unit-Specific Greenfield Siting Rules for EGEAS

Thermal unit siting uses a specific set of rules for each type of capacity. For instance, a coal unit has a different set of criteria than a combined cycle or combustion turbine. Also, demand-side resources have a completely different set of rules to follow when it comes to siting.

9.3.1 Greenfield Coal Siting Rules

Required Criteria:

- Within 1 mile of railroad or navigable waterway
- Outside 20-mile buffer of Class I lands
- Outside air quality non-attainment region
- Outside 25-mile buffer surrounding a major urban area (population greater than 50,000 and an area larger than 25 mi^2)
- Within 1/2 mile of a major river or lake

Optional Criteria:

- Within 20 miles of a coal mine or dock capable of producing more than 2 million tons per year
- Access to gas pipeline
- Multiple railroad lines

These rules for coal are input into MapInfo to show potential greenfield placement.

9.3.2 Greenfield Combined-Cycle Siting Rules

Required Criteria:

- Within 1 mile of railroad or navigable waterway
- Within 2 miles of river or a lake (lake has to be larger than 100 mi^2)
- Within 10 miles of a gas pipeline (diameter of 12 inches or greater)
- Within 25 miles of a major urban area

9.3.3 Greenfield Combustion Turbine Siting Rules

Required Criteria:

- Within 20 miles of railroad or navigable waterway
- Within 5 miles of a gas pipeline (diameter 12 inches or greater)

Optional Criteria:

- CTs can be located almost anywhere
- CTs historically have been located near metro areas, but not required
- CTs do not need a river for cooling
- Less likely to build pipeline for CT vs. CC
- CTs may be the preferred generation for coal retirement sites within metro areas

9.3.4 Greenfield Nuclear Siting Rules

Required Criteria:

- Use existing nuclear sites only
- All states are eligible for siting of future nuclear generation

9.3.5 Greenfield Wind Siting Rules

Required Criteria:

- Not in a state or national park
- Not in metro areas
- Not on state-managed lands
- Site wind within a state to meet its mandate, unless potential wind capacity is exceeded, then site in neighboring state(s)

9.3.6 Greenfield Photovoltaic Siting Rules

Photovoltaic (PV) will be sited using annual Solar Global Horizontal Irradiance (kWh/m^2). The Solar Global Horizontal Irradiance Intelligent Map Layer includes monthly and annual solar resource potential for the United States. The insolation values represent the average solar energy available to a horizontal flat plate collector such as a PV panel.

9.3.7 Demand Response and Energy Efficiency Siting Rules

Demand response capacity is sited at the top five load buses in each Load Serving Entity (LSE). If an LSE serves load in more than one state, the top five load buses in each state having a DR mandate or goal are used, with the DR being allocated based upon the percentage required in each state's mandate or goal.

The impact of energy efficiency is accounted for in the demand and energy growth rates, as EE is typically available during all 8,760 hours in a year.

This methodology applies to all Futures.

- Transmission is not an initial siting factor, but may be used as a weighting factor, all things being equal.
- Siting is done by region with the exception of wind units.
- Generation is distributed throughout the states in the study footprint; no one state will have all units sited within its borders; no one state will have zero units sited.
- Brownfield sites are preferable to Greenfield sites for gas units (CTs & CCs).
- Baseload units are sited in 600 MW increments and nuclear units, at 1,200 MW each.

- The total amount of expansion to an existing site is limited to no more than an additional 2,400 MW.
- Greenfield sites are restricted to a total of 2,400 MW.
- Use of Queue generation in multiple Futures should be limited.

9.4 Greenfield Siting Rules for EGEAS

Fuel Type/ Criteria	Railroad/ Navigable Waterway	Class lands	Non-attainment region	Urban Area	Major River/ Lake	Gas Pipeline	Coal Mine/ Dock
Coal	<1 LM	>20	O	>25	<0.5	PA	<20
Biomass	<1 LM	>20	O	>25s	<0.5	PA	-
CC	<1	>20	-	<25	<2	<10	-
CT	<20	>20	-	-	<1-2 L	<5	-

Table 20 Greenfield Siting Rules

L = “likes”: This feature is strongly preferred for siting a unit of this type.

LM = “likes multiples”: Multiple instances of this feature are strongly preferred for siting a unit of this type.

<x = “within x miles”: The unit should be sited within x miles of this feature.

>x = “outside of x miles”: The unit should be sited outside of x miles of this feature.

O = “outside”: The unit should be sited outside of the range of this feature.

PA = “prefer access”: Access to this feature is preferred, though not required.

10 Appendix 1 – Demand-Side EE (% of Avoided MWh Sales)

State	2020	2021	2022	2023	2024	2025	2026	2027	2028 l	2029	State Generation as % of sales	2012 Total MWh (sales x 1.0751)
Alabama	1.36%	2.11%	3.00%	4.01%	5.13%	6.19%	7.15%	8.01%	8.79%	9.48%	150.63%	92,655
Alaska	1.22%	1.95%	2.82%	3.82%	4.93%	6.02%	7.01%	7.91%	8.72%	9.45%	95.58%	6,898
Arizona	5.24%	6.28%	7.22%	8.07%	8.83%	9.50%	10.10%	10.61%	11.05%	11.42%	142.51%	80,701
Arkansas	1.52%	2.31%	3.24%	4.28%	5.42%	6.46%	7.41%	8.26%	9.03%	9.71%	113.99%	50,379
California	4.95%	6.04%	7.03%	7.93%	8.74%	9.46%	10.11%	10.67%	11.15%	11.56%	71.07%	279,029
Colorado	3.92%	5.08%	6.14%	7.09%	7.96%	8.73%	9.42%	10.03%	10.55%	11.01%	89.08%	57,717
Connecticut	4.71%	5.86%	6.92%	7.88%	8.76%	9.55%	10.25%	10.87%	11.42%	11.88%	106.16%	31,707
Delaware	1.14%	1.86%	2.73%	3.72%	4.83%	5.94%	6.96%	7.89%	8.72%	9.47%	45.09%	12,384
Florida	2.03%	2.91%	3.92%	5.03%	6.08%	7.04%	7.90%	8.68%	9.37%	9.98%	90.20%	237,247
Georgia	1.76%	2.60%	3.56%	4.63%	5.73%	6.74%	7.64%	8.46%	9.19%	9.83%	87.75%	140,815
Hawaii	1.29%	2.04%	2.92%	3.93%	5.05%	6.13%	7.11%	8.00%	8.80%	9.52%	96.24%	10,363
Idaho	3.80%	4.98%	6.06%	7.04%	7.93%	8.73%	9.44%	10.07%	10.62%	11.10%	46.83%	25,493
Illinois	4.36%	5.53%	6.60%	7.57%	8.46%	9.26%	9.97%	10.61%	11.16%	11.63%	126.99%	154,320
Indiana	3.20%	4.33%	5.49%	6.56%	7.53%	8.42%	9.22%	9.93%	10.56%	11.11%	102.84%	113,072
Iowa	4.65%	5.78%	6.82%	7.77%	8.62%	9.39%	10.08%	10.69%	11.21%	11.66%	113.03%	49,142

Kansas	1.22%	1.95%	2.83%	3.83%	4.95%	6.05%	7.05%	7.96%	8.78%	9.52%	110.28%	43,320
Kentucky	1.91%	2.78%	3.77%	4.87%	5.96%	6.95%	7.85%	8.66%	9.38%	10.02%	97.18%	95,736
Louisiana	1.14%	1.85%	2.71%	3.69%	4.78%	5.88%	6.88%	7.78%	8.60%	9.33%	90.08%	91,094
Maine	5.37%	6.47%	7.48%	8.39%	9.22%	9.96%	10.62%	11.20%	11.70%	12.13%	132.52%	12,429
Maryland	4.21%	5.38%	6.45%	7.44%	8.33%	9.13%	9.85%	10.48%	11.04%	11.51%	60.82%	66,456
Massachusetts	4.43%	5.60%	6.68%	7.66%	8.56%	9.37%	10.09%	10.73%	11.29%	11.77%	74.77%	59,467
Michigan	4.59%	5.74%	6.80%	7.77%	8.64%	9.43%	10.14%	10.76%	11.30%	11.77%	103.89%	112,690
Minnesota	4.80%	5.92%	6.95%	7.89%	8.73%	9.49%	10.17%	10.76%	11.28%	11.72%	82.84%	73,094
Mississippi	1.40%	2.17%	3.07%	4.09%	5.22%	6.28%	7.24%	8.11%	8.89%	9.59%	98.63%	52,022
Missouri	1.58%	2.38%	3.33%	4.39%	5.54%	6.60%	7.56%	8.43%	9.22%	9.92%	99.47%	88,626
Montana	3.36%	4.51%	5.63%	6.65%	7.57%	8.41%	9.15%	9.81%	10.39%	10.90%	207.68%	14,905
Nebraska	2.20%	3.13%	4.18%	5.34%	6.41%	7.38%	8.27%	9.06%	9.78%	10.40%	113.44%	33,143
Nevada	2.95%	4.02%	5.18%	6.24%	7.20%	8.07%	8.85%	9.54%	10.16%	10.69%	96.67%	37,822
New Hampshire	2.84%	3.90%	5.08%	6.19%	7.21%	8.14%	8.98%	9.74%	10.41%	11.00%	194.97%	11,687
New Jersey	1.25%	1.99%	2.87%	3.88%	5.00%	6.10%	7.11%	8.02%	8.84%	9.58%	76.19%	80,689
New Mexico	3.10%	4.19%	5.32%	6.35%	7.28%	8.11%	8.86%	9.52%	10.10%	10.60%	150.06%	24,919
New York	4.42%	5.59%	6.67%	7.65%	8.55%	9.35%	10.08%	10.72%	11.28%	11.76%	93.05%	153,914
North Carolina	2.37%	3.32%	4.39%	5.51%	6.53%	7.45%	8.28%	9.02%	9.68%	10.26%	86.12%	137,704
North Dakota	1.39%	2.16%	3.07%	4.10%	5.24%	6.32%	7.30%	8.19%	8.99%	9.71%	259.49%	15,822
Ohio	4.17%	5.35%	6.43%	7.42%	8.32%	9.13%	9.86%	10.51%	11.07%	11.56%	85.97%	163,906

Oklahoma	1.86%	2.71%	3.69%	4.79%	5.88%	6.88%	7.79%	8.60%	9.33%	9.97%	114.44%	63,797
Oregon	4.66%	5.77%	6.78%	7.69%	8.52%	9.26%	9.92%	10.49%	10.99%	11.41%	111.21%	50,195
Pennsylvania	4.67%	5.81%	6.85%	7.79%	8.65%	9.42%	10.11%	10.71%	11.24%	11.69%	142.20%	155,577
Rhode Island	3.90%	5.11%	6.22%	7.24%	8.17%	9.02%	9.78%	10.45%	11.04%	11.56%	97.63%	8,287
South Carolina	2.32%	3.26%	4.32%	5.45%	6.47%	7.40%	8.23%	8.98%	9.65%	10.23%	115.08%	83,622
South Dakota	1.60%	2.41%	3.36%	4.42%	5.57%	6.62%	7.57%	8.44%	9.21%	9.91%	82.32%	12,615
Tennessee	2.21%	3.14%	4.18%	5.33%	6.38%	7.33%	8.19%	8.97%	9.65%	10.26%	71.81%	103,620
Texas	1.78%	2.62%	3.59%	4.68%	5.78%	6.79%	7.70%	8.52%	9.26%	9.91%	98.12%	392,523
Utah	3.62%	4.82%	5.91%	6.91%	7.81%	8.62%	9.34%	9.98%	10.54%	11.03%	127.29%	31,956
Virginia	1.23%	1.96%	2.82%	3.81%	4.91%	5.98%	6.95%	7.83%	8.62%	9.33%	58.01%	115,890
Washington	4.24%	5.39%	6.43%	7.38%	8.24%	9.01%	9.69%	10.29%	10.81%	11.26%	107.69%	99,271
West Virginia	1.77%	2.62%	3.60%	4.70%	5.83%	6.86%	7.81%	8.66%	9.43%	10.11%	233.30%	33,132
Wisconsin	4.68%	5.82%	6.87%	7.83%	8.70%	9.48%	10.17%	10.79%	11.33%	11.79%	83.97%	73,988
Wyoming	1.61%	2.42%	3.35%	4.41%	5.53%	6.55%	7.48%	8.32%	9.07%	9.73%	256.15%	18,246

11 Appendix 2 – MISO Hub LMPs for All Years and Scenarios

Hub	BAU		
	2020	**2025**	**2030**
DSG Load	$ 46.21	$ 50.24	$ 58.80
MISOARK	$ 44.77	$ 48.08	$ 54.85
MISOILL	$ 40.33	$ 45.41	$ 54.39
MISOIND	$ 40.37	$ 30.67	$ 28.39
MISOLOUS	$ 45.97	$ 50.19	$ 58.69
MISOMICH	$ 43.58	$ 47.00	$ 55.79
MISOMINN	$ 37.35	$ 44.58	$ 52.31
MISOTEX	$ 46.89	$ 51.59	$ 60.51
Western Load	$ 46.87	$ 51.82	$ 61.22
WOTAB Load	$ 46.67	$ 51.31	$ 60.09
Average	$ 43.90	$ 47.09	$ 54.50

Hub	CPP – Regional Price ($/MWh)			CPP – State Price ($/MWh)		
	2020	2025	2030	2020	2025	2030
DSG Load	$ 54.23	$ 67.00	$ 86.16	$ 62.55	$ 82.34	$ 106.45
MISOARK	$ 52.69	$ 62.44	$ 79.83	$ 63.41	$ 82.97	$ 105.36
MISOILL	$ 51.06	$ 67.07	$ 84.76	$ 51.80	$ 67.19	$ 84.13
MISOIND	$ 51.24	$ 53.83	$ 56.89	$ 50.36	$ 50.42	$ 55.07
MISOLOUS	$ 54.57	$ 68.47	$ 88.12	$ 63.64	$ 83.59	$ 106.65
MISOMICH	$ 52.49	$ 67.62	$ 84.75	$ 52.79	$ 66.51	$ 82.96
MISOMINN	$ 48.37	$ 64.58	$ 80.19	$ 52.07	$ 71.08	$ 82.96
MISOTEX	$ 54.46	$ 68.59	$ 89.81	$ 63.48	$ 85.29	$ 110.92
Western Load	$ 52.39	$ 66.54	$ 86.41	$ 62.09	$ 86.19	$ 114.70
WOTAB Load	$ 53.41	$ 68.18	$ 88.71	$ 62.81	$ 85.42	$ 110.92
Average	$ 52.49	$ 65.43	$ 82.56	$ 58.50	$ 76.10	$ 96.01

Hub	C2G – Regional Price ($/MWh)			C2G – State Price ($/MWh)		
	2020	2025	2030	2020	2025	2030
DSG Load	$ 51.97	$ 58.52	$ 75.44	$ 61.41	$ 71.98	$ 93.22
MISOARK	$ 50.17	$ 55.85	$ 70.13	$ 62.07	$ 71.35	$ 89.02
MISOILL	$ 48.88	$ 56.38	$ 70.60	$ 50.78	$ 55.97	$ 68.48
MISOIND	$ 49.03	$ 47.55	$ 51.30	$ 48.94	$ 46.40	$ 46.56
MISOLOUS	$ 52.12	$ 58.75	$ 75.40	$ 62.38	$ 72.01	$ 91.30
MISOMICH	$ 50.30	$ 56.33	$ 70.02	$ 52.05	$ 55.75	$ 66.94
MISOMINN	$ 46.38	$ 55.30	$ 68.58	$ 50.55	$ 59.04	$ 70.31
MISOTEX	$ 51.93	$ 58.98	$ 75.61	$ 62.27	$ 74.13	$ 93.44
Western Load	$ 50.13	$ 57.92	$ 74.20	$ 61.12	$ 75.82	$ 97.22
WOTAB Load	$ 51.00	$ 58.74	$ 75.09	$ 61.70	$ 74.15	$ 93.53
Average	$ 50.19	$ 56.43	$ 70.64	$ 57.33	$ 65.66	$ 81.00

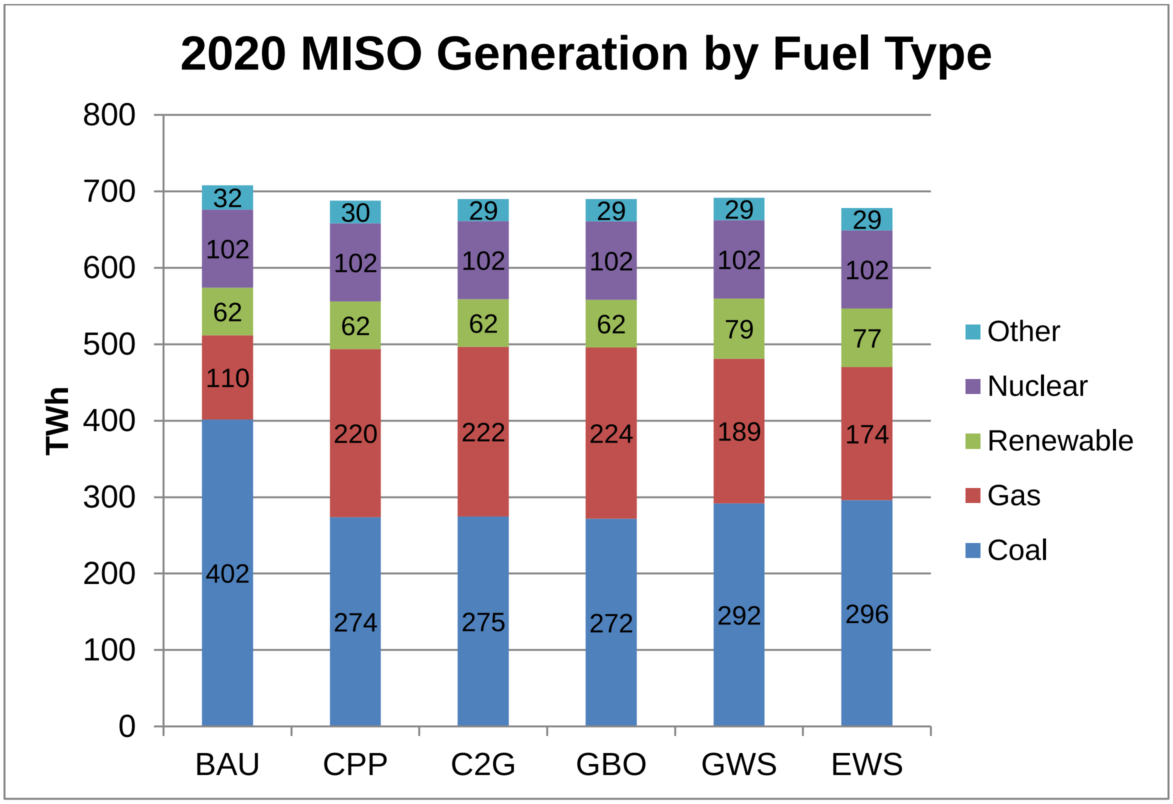
Hub	GBO – Regional Price ($/MWh)			GBO – State Price ($/MWh)		
	2020	2025	2030	2020	2025	2030
DSG Load	$ 51.62	$ 61.35	$ 78.90	$ 60.75	$ 74.77	$ 96.63
MISOARK	$ 49.81	$ 58.36	$ 73.64	$ 61.09	$ 73.65	$ 93.28
MISOILL	$ 48.39	$ 57.94	$ 73.22	$ 50.38	$ 56.87	$ 69.72
MISOIND	$ 48.35	$ 46.66	$ 48.24	$ 48.61	$ 43.27	$ 43.38
MISOLOUS	$ 51.78	$ 62.23	$ 79.51	$ 61.64	$ 75.69	$ 96.26
MISOMICH	$ 49.76	$ 58.04	$ 71.58	$ 51.38	$ 56.95	$ 68.83
MISOMINN	$ 46.21	$ 55.95	$ 69.40	$ 50.66	$ 59.29	$ 71.35
MISOTEX	$ 51.50	$ 62.11	$ 80.10	$ 61.52	$ 78.24	$ 100.28
Western Load	$ 49.87	$ 60.48	$ 78.37	$ 60.41	$ 82.35	$ 107.74
WOTAB Load	$ 50.66	$ 61.82	$ 79.54	$ 60.93	$ 78.93	$ 101.16
Average	$ 49.79	$ 58.49	$ 73.25	$ 56.74	$ 68.00	$ 84.86

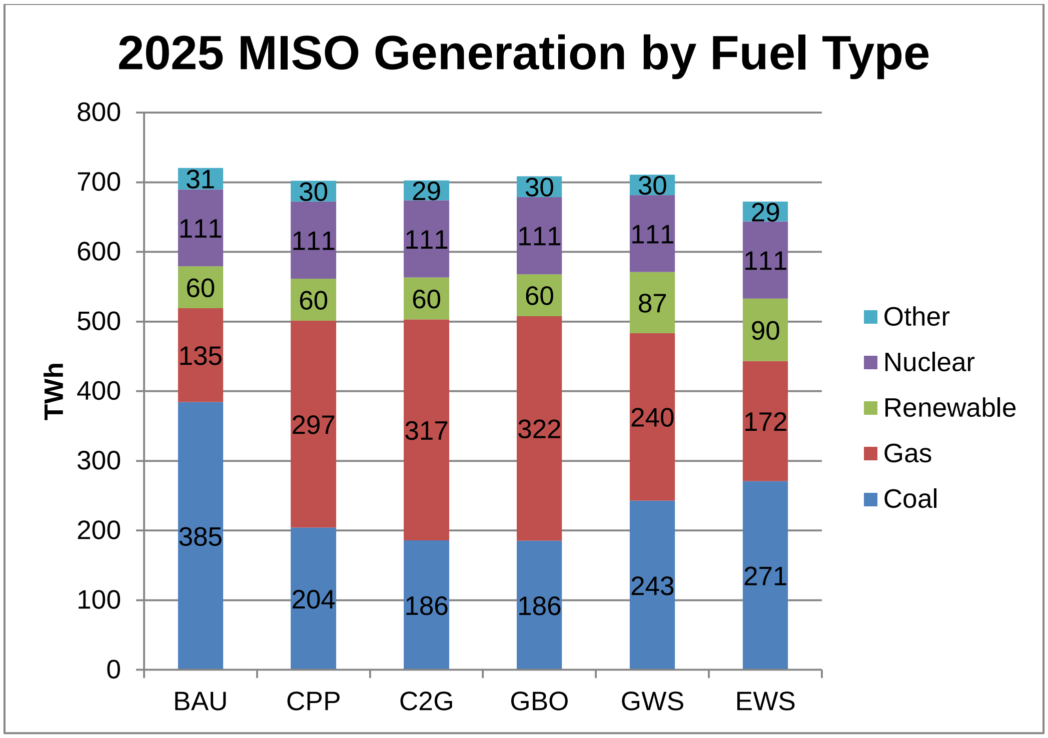
Hub	GWS – Regional Price ($/MWh)			GWS – State Price ($/MWh)		
	2020	2025	2030	2020	2025	2030
DSG Load	$ 53.16	$ 64.31	$ 79.46	$ 58.20	$ 71.08	$ 95.22
MISOARK	$ 51.70	$ 62.41	$ 74.04	$ 58.17	$ 70.71	$ 87.77
MISOILL	$ 47.65	$ 56.98	$ 69.25	$ 47.79	$ 57.21	$ 68.11
MISOIND	$ 47.40	$ 46.79	$ 46.21	$ 46.60	$ 41.42	$ 40.31
MISOLOUS	$ 53.30	$ 65.62	$ 79.56	$ 58.85	$ 72.25	$ 93.79
MISOMICH	$ 49.78	$ 58.60	$ 70.44	$ 50.21	$ 58.59	$ 70.33
MISOMINN	$ 44.90	$ 55.52	$ 66.31	$ 46.25	$ 58.49	$ 68.18
MISOTEX	$ 53.17	$ 66.15	$ 80.51	$ 59.12	$ 75.98	$ 101.01
Western Load	$ 51.50	$ 65.75	$ 80.58	$ 58.24	$ 80.17	$ 108.88
WOTAB Load	$ 52.41	$ 66.15	$ 80.42	$ 58.61	$ 76.67	$ 101.78
Average	$ 50.50	$ 60.83	$ 72.68	$ 54.20	$ 66.26	$ 83.54

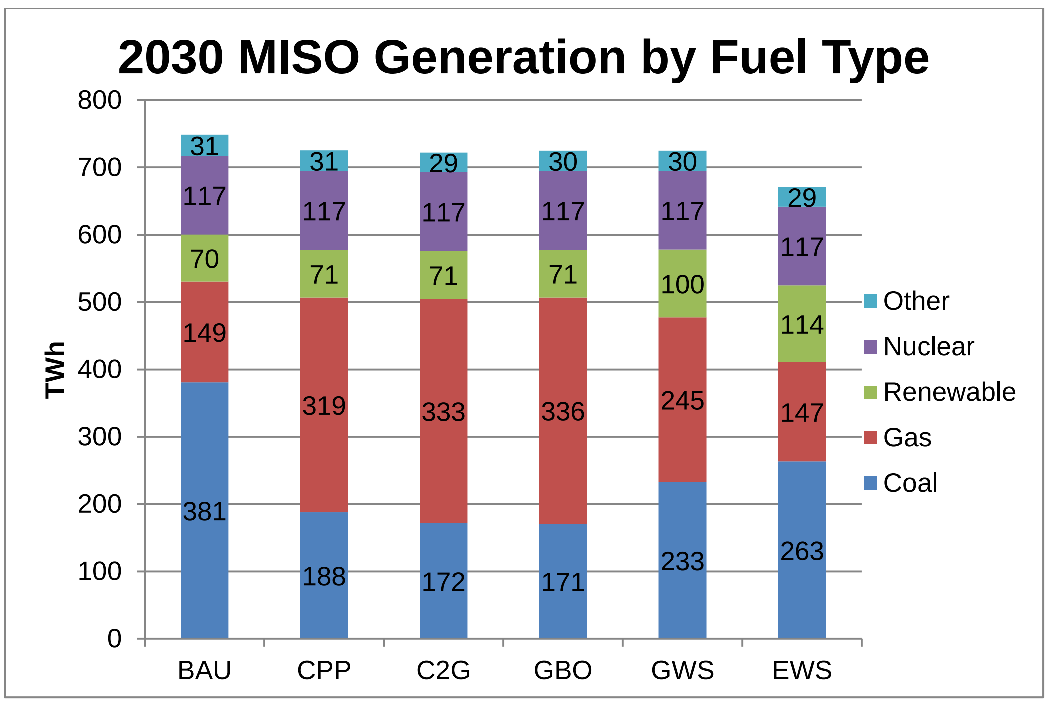
Hub	EWS – Regional Price ($/MWh)			EWS – State Price ($/MWh)		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
DSG Load	$ 29.93	$ 30.50	$ 32.13	$ 37.53	$ 32.92	$ 34.44
MISOARK	$ 43.76	$ 46.15	$ 51.71	$ 52.43	$ 52.51	$ 59.30
MISOILL	$ 43.97	$ 47.23	$ 52.86	$ 44.10	$ 46.57	$ 51.41
MISOIND	$ 44.08	$ 42.94	$ 42.26	$ 42.77	$ 37.64	$ 30.62
MISOLOUS	$ 47.41	$ 47.86	$ 50.63	$ 58.44	$ 51.90	$ 51.73
MISOMICH	$ 49.39	$ 53.00	$ 59.78	$ 52.18	$ 53.96	$ 60.28
MISOMINN	$ 41.05	$ 45.51	$ 50.33	$ 43.15	$ 47.00	$ 51.35
MISOTEX	$ 51.06	$ 51.52	$ 58.20	$ 62.06	$ 61.61	$ 72.31
Western Load	$ 37.76	$ 38.67	$ 44.74	$ 46.96	$ 46.41	$ 57.21
WOTAB Load	$ 45.75	$ 48.32	$ 56.45	$ 56.18	$ 57.88	$ 70.43
Average	$ 43.42	$ 45.17	$ 49.91	$ 49.58	$ 48.84	$ 53.91

12 Appendix 3 – MISO Fuel Mix for All Years and Scenarios

This section shows how generation in MISO changes over the compliance period under state by state compliance. The EWS scenario has less generation because of the deployment of energy efficiency in that scenario. Total generation decreases slightly because MISO imports more energy under these compliance scenarios. All states maintain compliance even with the change of imports and exports.



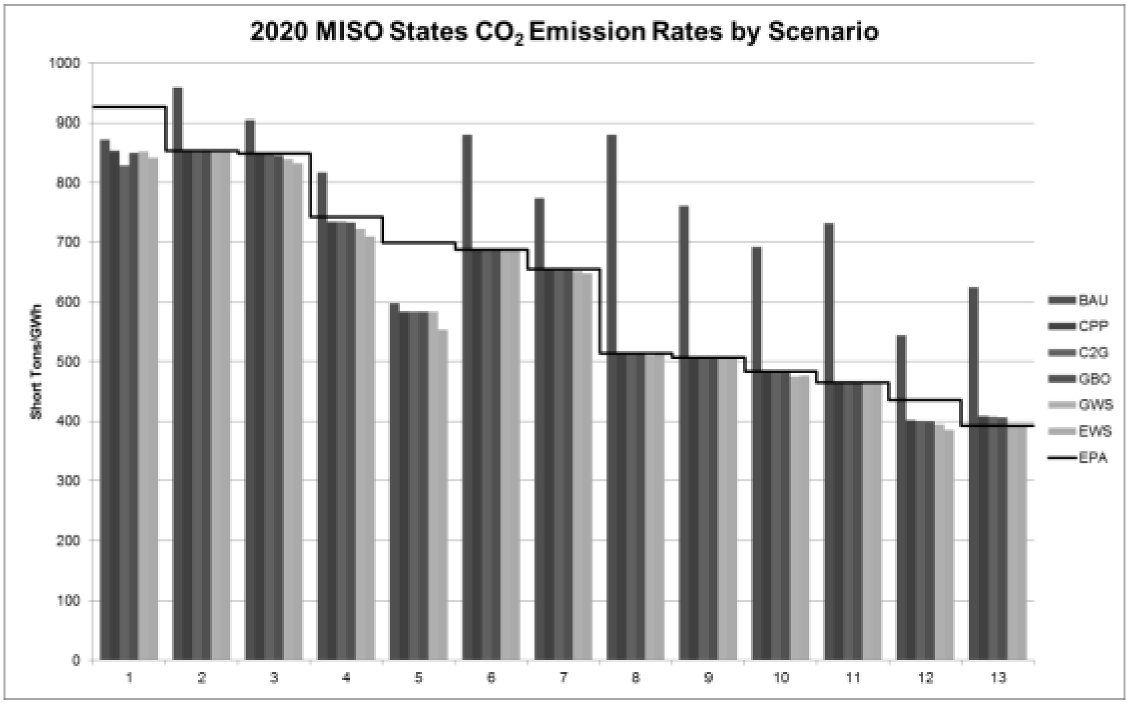

2025 MISO Generation by Fuel Type
TWh
800
700
600
500
400
300
200
100
0
BAU
CPP
C2G
GBO
GWS
EWS
31
111
60
135
385
30
111
60
297
204
29
111
60
317
186
30
111
60
322
186
30
111
87
240
243
29
111
90
172
271
Other
Nuclear
Renewable
Gas
Coal

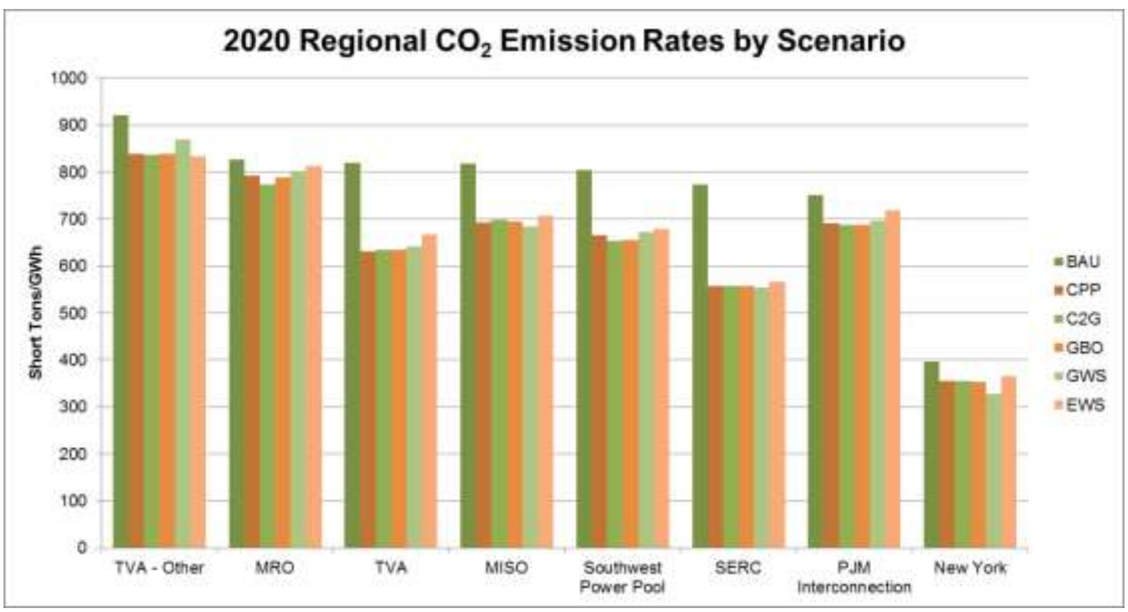

2030 MISO Generation by Fuel Type
TWh
800
700
600
500
400
300
200
100
0
BAU
CPP
C2G
GBO
GWS
EWS
31
117
70
149
381
31
117
71
319
188
29
117
71
333
172
30
117
71
336
171
30
117
100
245
233
29
117
114
147
263
Other
Nuclear
Renewable
Gas
Coal

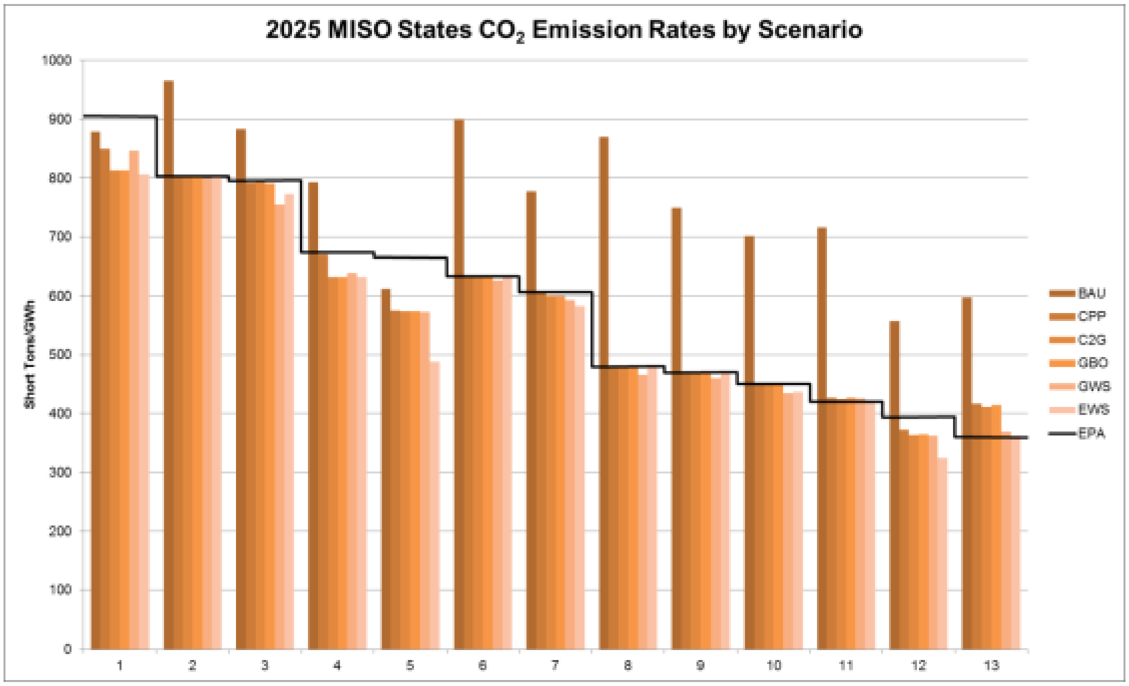
13 Appendix 4 – Costs for Transmission Portfolios

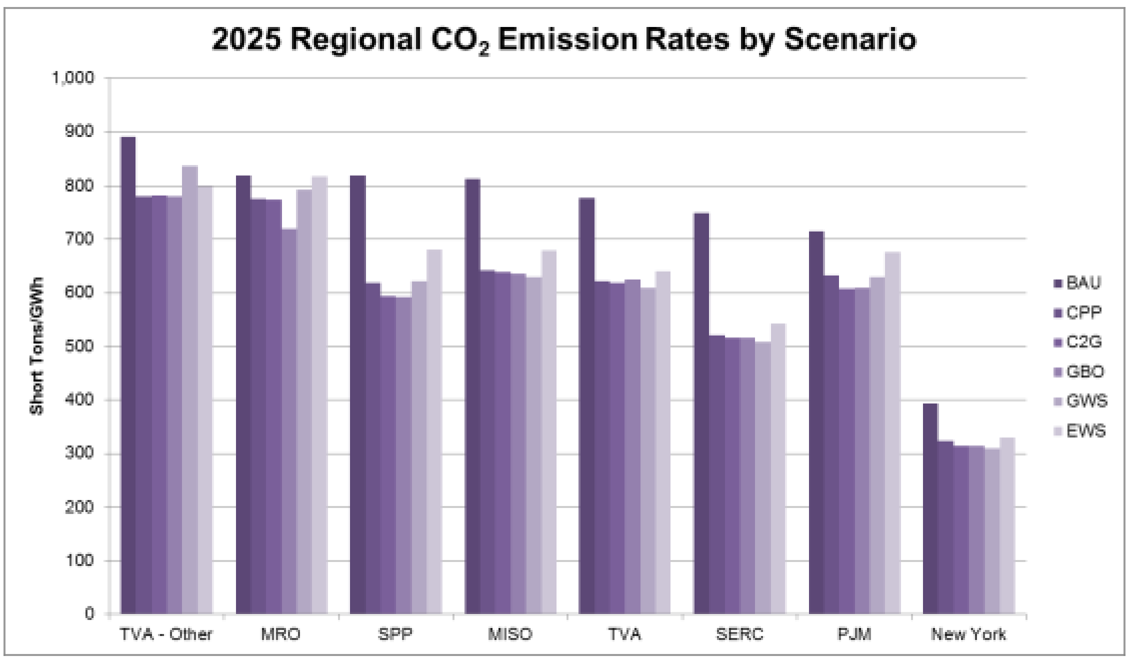
	Regional					State				
Solution	**CPP**	**C2G**	**GBO**	**GWS**	**EWS**	**CPP**	**C2G**	**GBO**	**GWS**	**EWS**
A1		123	123	123		123	123	123	123	
A2	109			109		109		109	109	
A3						500	115	115	115	115
i-1			24					24		
I-108			56							
I-16	127					127	127	127		
i2	28	28	28	28		28	28	28	28	
I-24			37			37	37	37		
i-26	67	67	67			67			67	
I-28									51	
i34	100	100	100	100	100	100	100	100	100	100
I-64	41		41					41		
I-76				126						
I-85		50	50	50		50	50	50	50	50
J1				144			144	144	144	
mec6	124	124		124	124	124	124		124	124
MS03A					75					
MS05						13	13	13		
MS11										
MS13					31					31
MS16				11		11	11		11	11
MS17	48	48	48	48	48	48	48	48	48	48
MS19					177					177
MS22	500	500	500	500	500	500	500	500	500	500
MS35A	37	37	37			37	37	37		
MS43		11		11	11	11	11		11	11
MS49A						126	126	126	126	
MS50									712	
MS59	59	59	59	59		59	59	59	59	
MS62				161					161	
MS76	225		225			225		225		225
MS77	345	345	345	345	345	345	345	345	345	345
N1		1	1				1	1	1	
N2				425					425	
	1,808	1,492	1,740	2,362	1,410	2,637	1,997	2,249	3,308	1,736

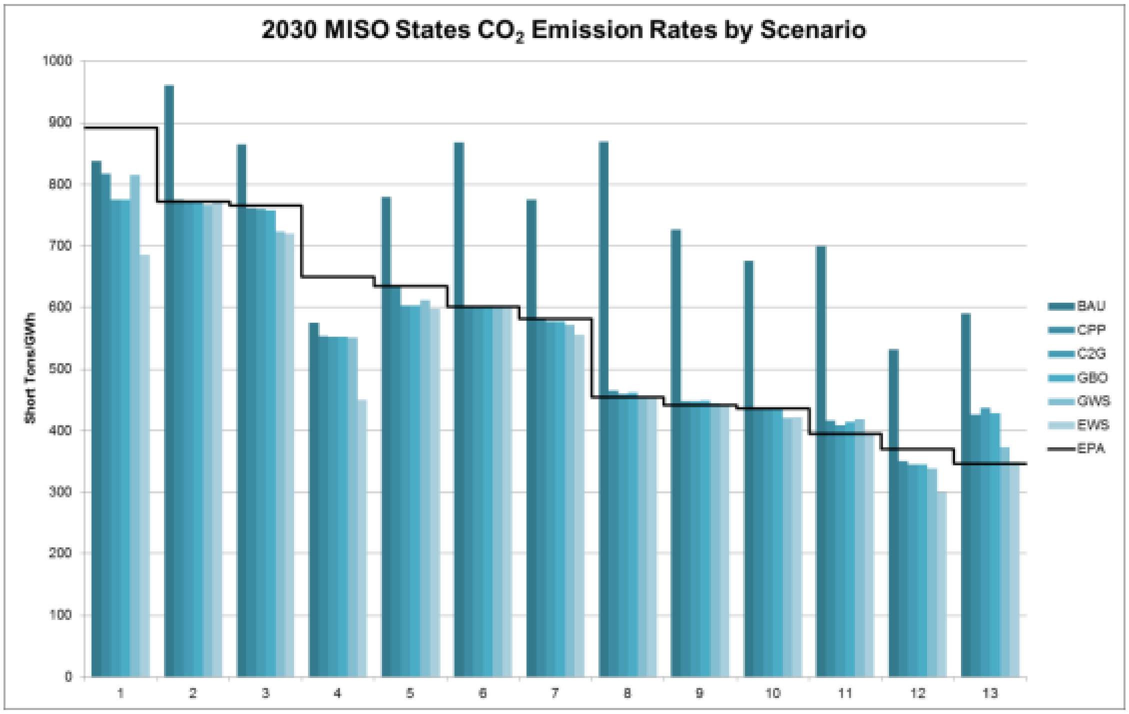
14 Appendix 5 – Emission Rates for All Years and Scenarios

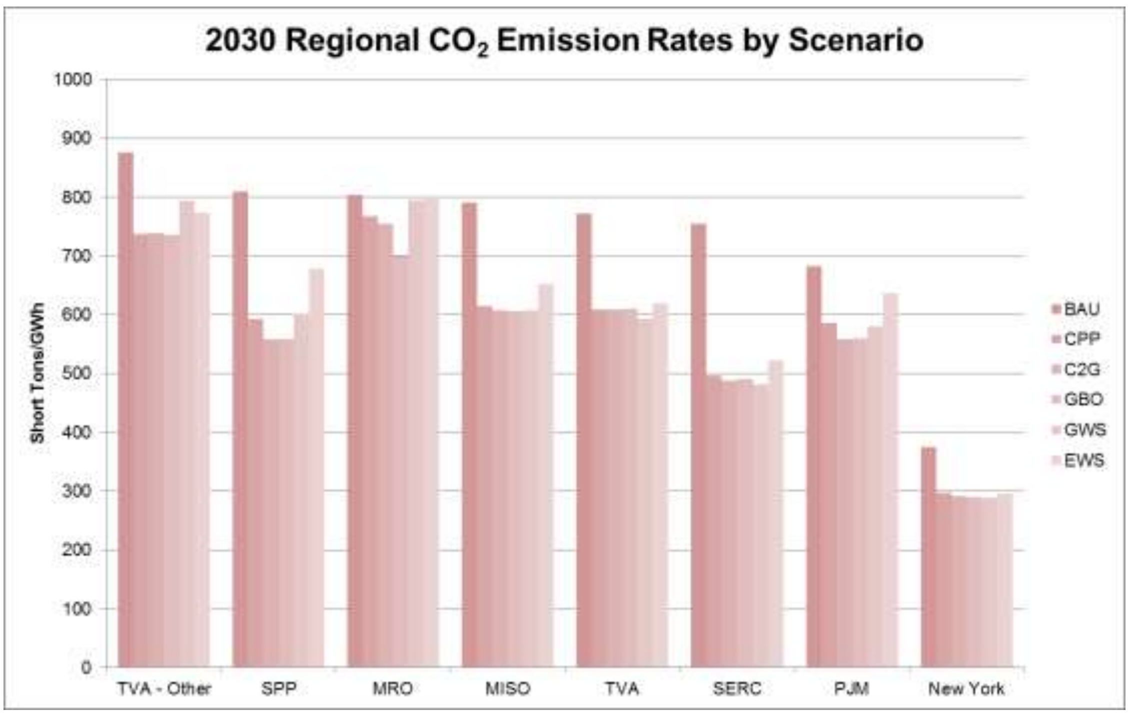





2025 MISO States CO_2 Emission Rates by Scenario
Short Tons/GWh
1000
900
800
700
600
500
400
300
200
100
0
1
2
3
4
5
6
7
8
9
10
11
12
13
BAU
CPP
C2G
GBO
GWS
EWS
EPA


2025 Regional CO_2 Emission Rates by Scenario
Short Tons/GWh
1,000
900
800
700
600
500
400
300
200
100
0
TVA - Other
MRO
SPP
MISO
TVA
SERC
PJM
New York
BAU
CPP
C2G
GBO
GWS
EWS


2030 MISO States CO_2 Emission Rates by Scenario
Short Tons/GWh
1000
900
800
700
600
500
400
300
200
100
0
1
2
3
4
5
6
7
8
9
10
11
12
13
BAU
CPP
C2G
GBO
GWS
EWS
EPA


2030 Regional CO_2 Emission Rates by Scenario
Short Tons/GWh
1000
900
800
700
600
500
400
300
200
100
0
TVA - Other
SPP
MRO
MISO
TVA
SERC
PJM
New York
BAU
CPP
C2G
GBO
GWS
EWS