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Understanding Clean Power Plan Choices in Michigan

Options and Uncertainties

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Abstract

This report summarizes analysis by the Electric Power Research Institute (EPRI), which looked at possible implications of alternative pathways for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Michigan. Conducted at the request of five Michigan utilities, EPRI's analysis investigated Michigan's options in preparing a state plan required by the CPP. EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was used to assess the relative costs of choosing mass- and rate-based CPP compliance targets across a range of scenarios representing potential developments of emission trading markets.

The analysis suggests that the state mass target applied to existing units, implemented as per the proposed Federal Plan, could be an attractive CPP compliance pathway for Michigan. This pathway is lower cost for the state than the performance-rate pathway where covered units face subcategory specific adjusted emission rate targets. It also potentially allows Michigan to comply without relying on the development of trading markets. These conclusions are robust to key uncertainties, including the natural gas price path, the lifetime of Michigan's remaining coal units, and the development of trading markets.

The results indicate that Michigan's primary compliance strategy may be to shift from coal generation to natural gas and renewable generation. Thus in all but one of the 27 compliance scenarios examined, Michigan coal generation in 2030 fell approximately 30% versus 2015 levels, whether due to pre-planned coal unit retirement decisions, or incentivized by the CPP directly.

Keywords
Clean Power Plan
Michigan
US-REGEN

Executive Summary

This report summarizes analysis by the Electric Power Research Institute (EPRI), which looked at the implications of alternative pathways for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Michigan. Conducted at the request of five Michigan utilities, EPRI's analysis investigated Michigan's options in preparing a state plan required by the CPP. Specifically, the analysis assesses mass and rate CPP pathways for Michigan with and without market participation under a range of sensitivities.

EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was used to compare CPP compliance results to an appropriate reference scenario (i.e., without the CPP) to understand tradeoffs between Michigan's planning options. In addition to rate and mass pathways, the analysis considers alternate trading scenarios to understand how reliance on in-state measures, versus participation in inter-state emissions trading markets, influences outcomes.

Over the next 15 years, it is likely that Michigan will see multiple fossil unit retirements, and thus will need to replace significant coal generation regardless of the Clean Power Plan. As a consequence, Michigan's CPP choices serve mainly to influence the types of new investments made, rather than requiring large additional investments for compliance. This implies the additional costs to comply with the Clean Power Plan would be relatively low in many scenarios compared to total electric sector costs in the reference case. Under reference assumptions, in the absence of the CPP, Michigan would be largely in compliance with the existing mass target, close to compliance with the mass + new source complement (NSC) target, and short of compliance with the performance rate target, between now and 2030.

Key Takeaway 1: Either mass-based Clean Power Plan pathway would be lower cost for Michigan than the performance rate pathway. This conclusion holds across all modeled sensitivities.

This analysis suggests that the existing mass target, implemented as per the proposed Federal Plan, may be an attractive CPP compliance pathway for Michigan. It is lower cost than the performance rate path due to the large number of expected coal retirements, it does not rely on purchasing allowances from out-of-state, and the primary compliance mechanism – reduce coal generation and replace it with existing and new natural gas combined cycle (NGCC) generation – is stable across a range of sensitivity scenarios. In contrast, least cost

Key Takeaway 2: Least cost CPP compliance in Michigan could require ~30% reduction in coal generation by 2030 vs. 2015.

compliance with the performance rate pathway would depend strongly on the development of trading markets for emission rate credits.

The analysis also suggests the mass + NSC pathway would be lower cost than performance rate, and in some cases would have slightly lower costs than the existing mass pathway. This is due to the addition of the NSC raising the cap slightly, plus an expectation that Michigan could import electricity generated by new NGCCs from other states rather than invest in-state under this pathway. If Michigan were desiring to build new natural gas generation in-state, then the existing mass pathway could be significantly cheaper than the mass + NSC pathway, particularly beyond 2030.

The results indicate that Michigan's primary compliance strategy would be to shift from coal generation to natural gas and renewable generation. Thus in all but one of the 27 compliance scenarios examined, Michigan coal generation in 2030 fell approximately 30% versus 2015 levels, whether due to pre-planned coal unit retirement decisions, or incentivized by the CPP directly.

The flexible compliance options states can adopt under the CPP makes decision-making more complex, requiring state-of-the-art optimization and economic modeling tools to understand tradeoffs and impacts. Regional heterogeneity means that there is not a dominant approach for all states, and the interdependence of state actions (which are affected by actions elsewhere) means that decisions must be evaluated simultaneously. The US-REGEN framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets, enabling a representation of market interactions for electricity, CO_2 allowances, and emission rate credits.

Although this analysis offers valuable insights for state-level CPP decision-making in Michigan, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for Michigan. Each state's preferred portfolio of compliance measures (e.g., in-state actions and market participation) will be informed by a range of factors, including in-state compliance costs, risk tolerance, local incentives, and assumptions about market liquidity and participation. Actual deployment will depend on additional factors (e.g., policy, permitting, legal cases, and uncertainty) that fall outside of the scope of this economic modeling and analysis.

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Section 1: Introduction

This report summarizes analysis by the Electric Power Research Institute (EPRI), which looked at comparative costs, investment implications, and other impacts of alternative pathways for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Michigan. The report is intended to gain insight into Michigan's available options in preparing its CPP state plan. The analysis was conducted with funding from a consortium of Michigan utilities, including Consumers Energy, DTE Energy, Michigan Public Power Agency, WEC Energy Group, and Wolverine Power Cooperative.

The U.S. Environmental Protection Agency's Clean Power Plan

On August 3, 2015, the U.S. Environmental Protection Agency released its *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, also known as the Clean Power Plan.[1]

Promulgated under Section 111(d) of the Clean Air Act (CAA), the Clean Power Plan requires each state to create a plan demonstrating how it will meet emission reduction mandates (which vary from state to state) for existing fossil-fueled electric generating units (EGUs).

The state plans determine the form and extent of carbon dioxide (CO_2) emission reduction requirements for affected EGUs. The EPA identifies six main compliance pathways for states, three of which are based on EGU emission rates and the others on mass-based emission totals. The CPP provides flexibility for states to develop other compliance approaches, subject to EPA approval. In addition to pathway selection, a second decision for states is to determine the degree of participation in inter-state trading programs.

On February 9, 2016, the Supreme Court issued a stay on implementation of the CPP while the lower courts review pending legal challenges. The impact of the stay on CPP requirements and timetables was uncertain at the time of this report's preparation.

[1] The CPP was published in the Federal Register on October 23, 2015. EPRI's summary and interpretation of the CPP is provided here as background information and is not legal advice.

Motivation for the State-Level Analysis of Clean Power Plan Options for Michigan

The flexibility of alternate CPP pathways, along with other options for inter-state trading of CO_2 allowances in mass compliance settings and emission rate credits (ERCs) in rate settings, is intended to help states manage compliance costs; however, these options come with detailed provisions and state-specific factors that require careful analysis. The differences in these pathways may be worth billions of dollars for individual states. The challenge for state planners is, amongst other things, knowing how the choices affect compliance costs, implementation decisions, and long-term resiliency in an uncertain world.

EPRI's electric sector model (**US-REGEN**) represents key state-level CO_2 mitigation options and economic tradeoffs.

Since 2012, EPRI Program 103 (*Analysis of Environmental Policy Design, Implementation, and Company Strategy*) has been creating tools for its members and the public to understand the potential impacts of the Clean Power Plan on electric utility assets and operations, and to devise cost-effective compliance strategies.

A cornerstone of Program 103 is the continuing development and refinement of the U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. US-REGEN provides a platform for analyzing CPP impacts on the electric utility sector, providing insights into how alternate choices of compliance pathways and trade may affect electricity generation, investments, emissions, and costs. In addition to US-REGEN model development, datasets have been created and updated to characterize electricity generation technologies and their costs, renewable energy resources, and specifics of CPP compliance options at the state level. [2]

The research undertaken in Program 103 has focused on national and regional implications of the Clean Power Plan. In 2015, a supplemental project was offered providing US-REGEN based analyses with in-depth consideration of CPP implementation at the state level. A number of these studies were initiated by groups of utilities, including the Michigan study discussed in this report.

[2] See Appendix A for additional information about the US-REGEN model.

Section 2: Analysis Approach

The analysis strategy is to compare policy and uncertainty scenarios to an appropriate reference case (i.e., without the CPP) to gain insight into the impacts of alternative CPP implementation pathways. The US-REGEN model provides an analytical testbed for conducting controlled experiments to investigate differences among scenarios.

EPRI's US-REGEN Model Structure, Data, and Assumptions

The U.S. Regional Economy, Greenhouse Gas, and Energy (**US-REGEN**) model was developed by the Electric Power Research Institute. The model combines detailed power sector capacity planning for the Lower 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the economy.[3] The two models are solved iteratively to allow policy impacts on the electric sector to account for economic responses (and vice versa), which means US-REGEN can assess a wide range of energy and environmental policies. The analysis in this report uses the electric-sector model only.

The electric model simultaneously determines a cost-minimizing solution for all 48 states subject to technical and policy-related constraints. US-REGEN's spatial and temporal detail captures resource adequacy for each state and capture market dynamics not only for electricity but also for CPP-related trading of allowances (for mass-complying states) and emission rate credits (for rate-complying states).

The model results are intended to preserve critical details of asset investment, systems operations, and environmental compliance options. However, the results are not intended to be forecasts or predictions of future states-of-the-world. Insights are driven by changes across scenarios in "what-if" analyses under different sensitivities, not by absolute levels.

Although this analysis offers valuable insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for Michigan, for multiple reasons.

[3] The CGE model of the U.S. economy includes representations of the residential, commercial, industrial, transportation, and fuels processing sectors.

- Actual deployment will depend on many additional factors, such as policy, judicial outcomes, permitting, and other uncertainties.
- The modeling of the existing mass pathway in this analysis is based on the proposed Federal Plan, which gives guidelines on how states could control 'leakage' if they do not explicitly cover new units under a cap. These guidelines are subject to change in the final Federal Plan, which could change the incentives to deploy renewables under the existing mass pathway.
- US-REGEN's focus on modeling all 48 states CPP decisions simultaneously from 2015-2050 does impose computational limitations on how much detail the model can represent within any given state. The model does not consider unit commitment constraints in dispatch decisions, nor does it consider transmission constraints within a state, or issues associated with gas distribution to the unit. All of these could impact the representation of CPP mitigation measures. For example, US-REGEN is likely more optimistic about the potential for coal to gas re-dispatch than a production cost model would be, as it does not 'see' gas distribution constraints.

Detailed discussions of US-REGEN's data and structure are provided in Appendix A of this report, and in the US-REGEN documentation.[4]

Analysis Structure

The analysis focuses on the "performance rate", "existing mass", and "mass + NSC" Clean Power Plan compliance pathways for Michigan.

The analysis focuses on state-level decisions for Michigan to help understand the implications of different CPP compliance pathways. As shown in Figure 2-1, the four main paths considered include two rate-based ("Performance Rate" and "State Rate") and two mass-based ("Existing Mass" and "Mass + NSC") pathways. Preliminary analysis suggested that the study should focus on the performance rate (hereafter referred to as the "rate" target), the mass cap for existing units only (hereafter referred to as the "existing mass" target), and the mass cap for new and existing units (hereafter referred to as the "mass + NSC" target, where NSC means new source complement).

[4] Additional detail can be found in *US-REGEN Model Documentation 2014*, EPRI Technical Update #3002004693 (available online at http://eea.epri.com/models.html).

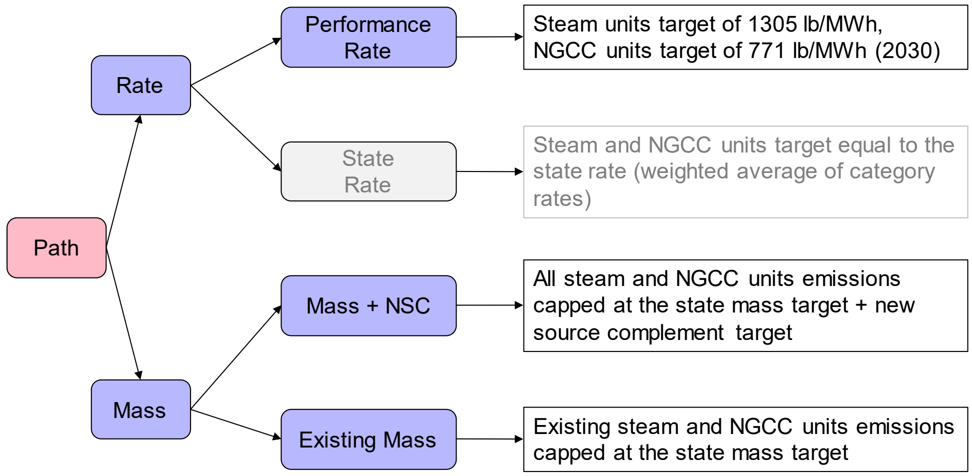

Figure 2-1
Diagram of Clean Power Plan compliance pathways considered in the analysis

The objective of the analysis is to inform state-level decisions about potential CPP compliance pathway choices for Michigan. In the analysis, the primary metric for the decision is the comparative costs to the state of these pathways, though other criteria are also discussed in the report. Due to uncertainties about the future (e.g., natural gas prices, asset lifetimes, renewables costs), the analysis investigates the relative costs of rate and mass paths under a range of sensitivities, as discussed in the next subsection.

The flexible compliance options a state can adopt under the CPP makes decision-making more complex, requiring state-of-the-art optimization and economic modeling tools to understand tradeoffs and impacts. Assessments must be conducted on a state-by-state basis given different targets, portfolios of existing assets, and compliance options. Regional heterogeneity suggests that there is no dominant approach for all states, and the interdependence of states' actions (which are affected by actions elsewhere) means that decisions must be evaluated simultaneously. The US-REGEN framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets. This unique structure allows US-REGEN to represent market interactions for electricity, renewable energy certificates, CO_2 allowances, and emission rate credits to assess economic impacts and trading possibilities of policies like the CPP.

Unless noted, cost comparisons in the report refer to electric-sector-only cost impacts and include:

- All capital and operating costs
- Cost of new transmission (evenly apportioned between states on the line) plus maintenance
- Regulatory costs (e.g., alternative compliance payments for renewable portfolio standards, etc.)

- Cost of imported electricity, priced at the marginal wholesale price of the exporting state (minus the cost of exported electricity)
- Net payments for CPP credits and allowances

CPP compliance costs are incremental electric-sector costs above the reference ("no CPP") scenario. All values are expressed in real 2010 dollar terms.

Costs do not include gas infrastructure and transportation costs. These are outside the scope of the modeling, and thus are effectively assumed constant across scenarios.

All cost values are expressed in 2010 dollar terms, with future costs discounted back to 2010 at a discount rate of 5%. Note that cost comparisons on this basis differ from impacts on consumer electricity prices/rates.

CPP costs are defined as the incremental electric-sector costs above those incurred in the reference case, which makes it critical to define the reference scenario carefully and to present results explicitly (as discussed in Section 3).

It is worth reiterating that the goal of this project is not to predict the future by forecasting values of specific variables, but to gain insight about the strengths and shortcomings of different pathways based on relative costs. Not only are costs intrinsically uncertain, but the Supreme Court stay creates further cost uncertainty due to potential changes in the regulatory landscape in yet unknown ways.

Many caveats about the uses and limitations of economic models should be kept in mind when interpreting results from this analysis. Models like US-REGEN are by necessity numerical abstractions of the complex economic and energy systems they represent. As such, they may contain approximation errors, incomplete system dynamics, and data quality issues. When viewing results, it is important to keep in mind that insights come from running a variety of scenarios, comparing the results, and asking "what-if" questions.

Scenario Descriptions

Section 3 summarizes reference case assumptions, results, and CPP compliance. Section 4 investigates CPP compliance for Michigan under so-called "island" conditions (i.e., where compliance is achieved using only in-state resources or by adjusting power imports/exports). Section 5 looks at the potential role of trading emissions allowances or ERCs, which are exported or imported from other states to reduce compliance costs.

The sensitivity of these results to key assumptions, including the natural gas price path and retirement plans for the existing coal fleet, is discussed throughout each section. Finally, Section 6 compares the CPP compliance costs to the state for every scenario and sensitivity modeled.

Section 3: Reference Scenarios

US-REGEN model results in this section focus on a reference scenario that describes how electricity generation in Michigan might evolve between 2015 and 2030 in the absence of the Clean Power Plan. The analysis strategy is to compare CPP compliance results to an appropriate reference to understand the tradeoffs between Michigan's CPP planning options. As discussed in Section 2, the reference scenario is intended to be realistic but is not a forecast of the future. As such, insights are driven by relative changes across scenarios.

Over the next 15 years, Michigan is likely to see multiple fossil unit retirements, regardless of the Clean Power Plan. Much of the existing fleet is aging, and either has an announced closing date, or is likely to close by 2030.[5] This includes almost 50% of the existing coal fleet, as measured by GW capacity. New investments will likely be needed to replace generation from these retiring units – the reference scenario developed in this analysis includes $7 billion in overnight capital costs alone from 2016-2030.[6] This context is important for understanding the impact of the Clean Power Plan in Michigan. Because the reference scenario already includes substantial new investments, additional costs to comply with the Clean Power Plan would be relatively low in most scenarios compared to total electric sector costs in the reference case. Michigan's CPP choices serve mainly to influence the types of new investments, rather than requiring large additional investments over the reference case.

Assumptions for the Reference Scenario

The reference scenario is derived from running US-REGEN for the 48 contiguous states, which is calibrated to each state's 2015 generation by technology and then simultaneously solves the cost-minimizing capacity problem through 2050.

[5] The analysis for this report was completed before DTE's June 8, 2016 announcement of its intent to retire eight coal units at its River Rouge, Saint Clair, and Trenton facilities by 2023. However, the Reference scenario does assume all these units will retire. See the discussion of coal unit retirements later in this section.

[6] This number includes both supply and demand-side investments, but excludes costs of importing additional power from out-of-state.

Without the Clean Power Plan or additional policies, new natural gas and wind capacity are on the build margin in many states.

Key assumptions in the reference scenario include:

- Load growth and fuel prices come from the Energy Information Administration's (EIA) 2015 Annual Energy Outlook (AEO)
  - Load growth includes existing (legacy) energy efficiency programs, assuming states continue programs at average 2010–2014 rates and this efficiency qualifies for ERC credit[7]
  - Fuel price paths come from the high estimated ultimate recovery (i.e., low fuel price) case
- Fleet database was updated in December 2015 (through the ABB Velocity Suite) plus announced retirements
- Existing NGCC units have a 40 year lifetime, and existing nuclear units have 60–80 year lifetimes. Existing coal lifetimes were set on a unit by unit basis using a combination of announced retirement dates from the ABB Velocity Suite, and likely retirement dates for scenario purposes suggested by the Michigan utilities.
- Technology costs come from the EPRI Generation Options report[8] with recently updated solar and wind costs
- Existing policies include state renewable portfolio standards (RPSs), the Regional Greenhouse Gas Initiative (RGGI), California's AB 32, and recent extensions of the Production Tax Credit (PTC) and Investment Tax Credit (ITC)
- CAA § 111(b) CO_2 performance standards for fossil units are included for new units
- Wind and solar resource data for most states comes from a database provided by AWS Truepower. For Michigan, study participants agreed to use wind resource numbers from the Michigan Wind Resource Study (2009)[9], which assumes a maximum of 6.1GW of new onshore wind can be constructed in Michigan; 4GW at a capacity factor of 37% and the remainder at 31%.

Figure 3-1 shows electricity generation by technology across the U.S. in the reference scenario. In this analysis, the PTC for wind accelerates deployment rather than incenting incremental capacity additions in many states.[10] The modeling results suggest retirements of existing capacity and rising demand are met primarily by new natural gas combined cycle (NGCC) units, which are on

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[7] This analysis assumes that the AEO load growth projections used have already subtracted this "legacy energy efficiency". It is reported out here explicitly because of the possibility these measures could provide credit towards CPP compliance. See Appendix A for more details.

[8] Electric Power Research Institute. "Program on Technology Innovation: Integrated Generation Technology Options 2012." Technical Update 1026656.

[9] Available at www.dleg.state.mi.us/mpsc/renewables/windboard/werzb_final_report.pdf

[10] The reference scenario assumes net metering in California only, which leads to more rooftop solar deployment compared with other states.

the margin in many states under the reference case assumptions for gas prices and technological costs.

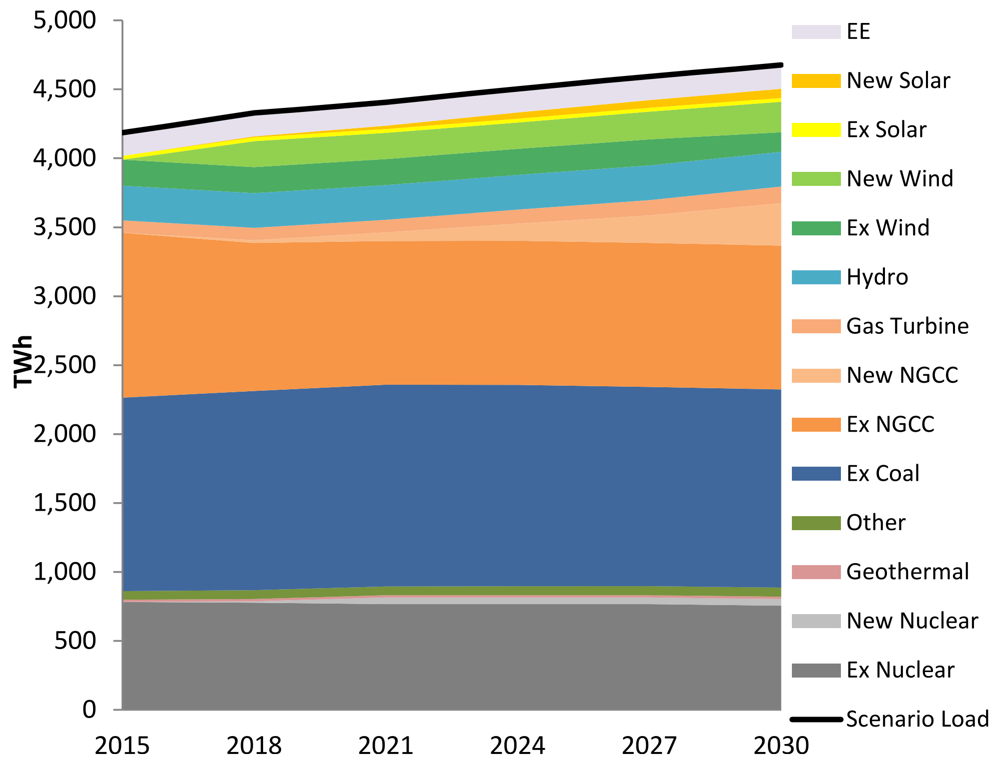

Figure 3-1
Electricity generation (terawatt-hours) in the Lower 48 U.S. states by technology under the reference (i.e., no Clean Power Plan) scenario (2015–2030)

Generation, Capacity, and Emissions Results for Michigan without the Clean Power Plan

Figure 3-2 shows electricity generation results for the reference scenario for Michigan. Generation from existing coal units (dark blue) declines steadily through 2030. This is replaced by a mix of new wind (light green), driven largely by a combination of Michigan's RPS and the PTC, and new NGCC units (light orange). The existing nuclear fleet (dark grey) is assumed to continue operation through 2030.[11] Michigan's legacy energy efficiency programs generate 4.2 TWh annually (light grey), which, in addition to some new energy efficiency measures,

[11] The project team identified good arguments for alternatively assuming that Palisades would retire in 2022 instead of 2031. A scenario was run to test the impact of this assumption, which found that Palisades would be replaced with new NGCC units, but the insights on Michigan's CPP choices remained unchanged.

totals over 3% of load per year, exceeding Michigan's energy efficiency standards.[12]

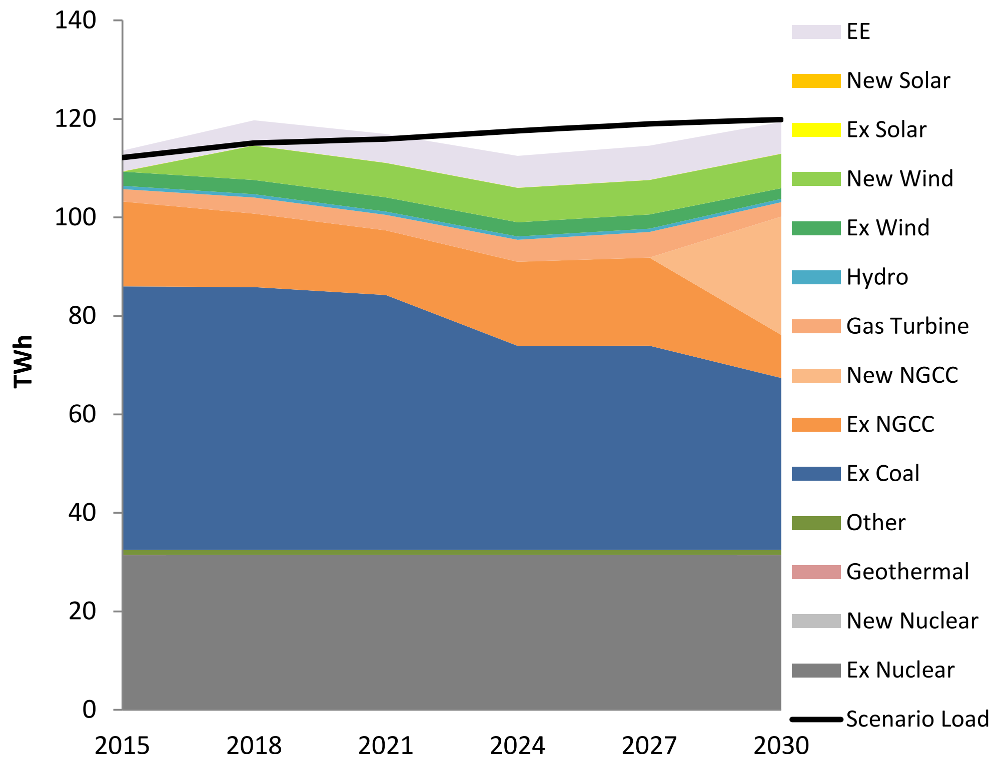

Figure 3-2
Electricity generation (terawatt-hours) in Michigan by technology under the reference (i.e., no Clean Power Plan) scenario (2015–2030)

Without the Clean Power Plan, Michigan's fleet in the reference case transitions gradually away from coal, to a mixture of new wind and NGCC units.

In years where total generation resources, including energy efficiency, fall short of the black line representing total load for the scenario (e.g., 2022 through about 2030), power is being imported into Michigan. In years where total generation is above the scenario load line, power is exported from the state.

Figure 3-3 underscores how the reference scenario includes substantial new investments between 2016 and 2030, notably additional new wind and new NGCC units. The latter are the lowest-cost capacity additions for Michigan in the reference case, given the relatively low gas price path assumed in the reference scenario. The new wind is driven by the Production Tax Credit. The following section will illustrate how the CPP may modify the mix of new investments planned for Michigan.

[12] Legacy energy efficiency is assumed to be already included in the AEO load growth forecast, whereas new energy efficiency directly reduces load growth in the modeling. New energy efficiency measures are assumed to cost $55/MWh avoided. See Appendix A for more details.

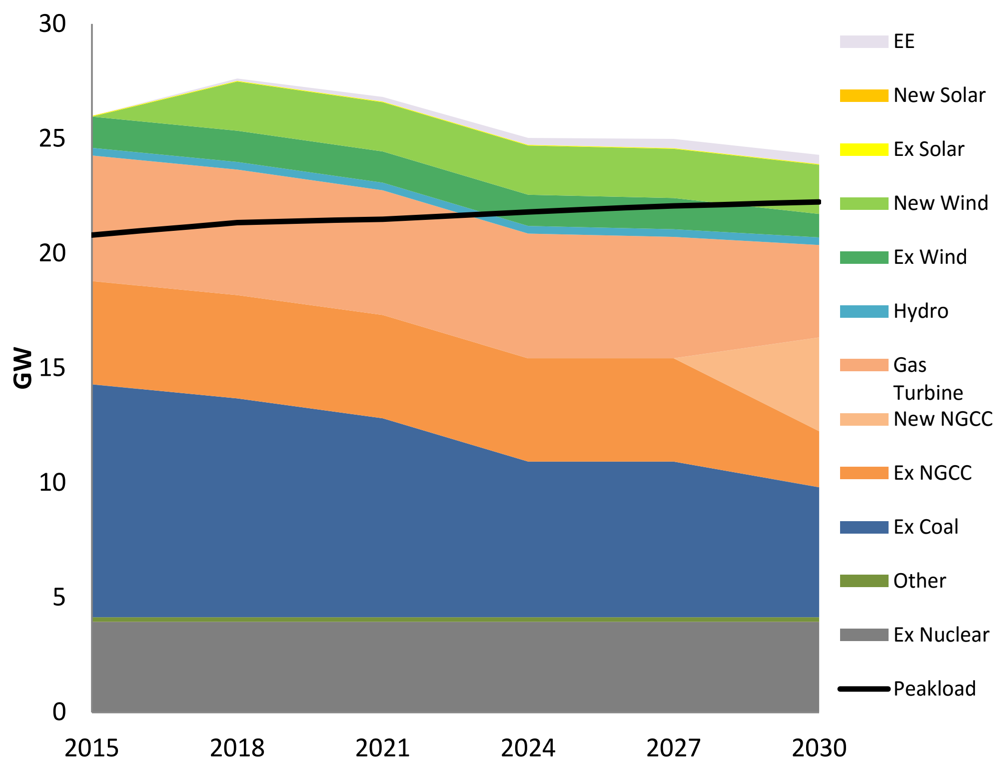

Figure 3-3
Electricity capacity (gigawatts) in Michigan by technology under the reference (i.e., no Clean Power Plan) scenario (2015–2030)

Sensitivity Scenarios

The choice of reference assumptions can influence whether a state would prefer a mass or a rate CPP pathway, based on the cost of compliance to the state. For example, assumptions that make new wind more economic relative to gas in Michigan would lower the cost of complying with a rate target versus a mass target, as new wind units generate ERCs for rate compliance. Alternatively, assuming a greater number of coal unit retirements would decrease CO_2 emissions from existing units, and thus decrease the cost of complying with both mass and rate targets.

For a robust analysis of reference assumption impacts, the project team tested a large number of sensitivities to the reference scenario assumptions, including the price of natural gas, the cost of energy efficiency measures, the quantity of new wind resource in Michigan, the lifetime of existing coal units, and the possibility of additional CO_2 policies post-2030. Of these, only two showed the potential to significantly alter the cost of CPP compliance in Michigan: the natural gas price path and the lifetime of the existing coal fleet. The first alters the economics of wind versus gas, which is a key determinant of the cost of rate versus mass. The second alters CO_2 emissions from existing units in the reference case, with consequences for both rate and mass targets.

Two natural gas price paths were considered. The reference scenario uses the price path from the AEO2015 HEUR case. The "HighGasPrice" scenario uses a higher gas price path from the AEO2015 Reference case. These are depicted in Figure 3-4 in real 2010 dollars.

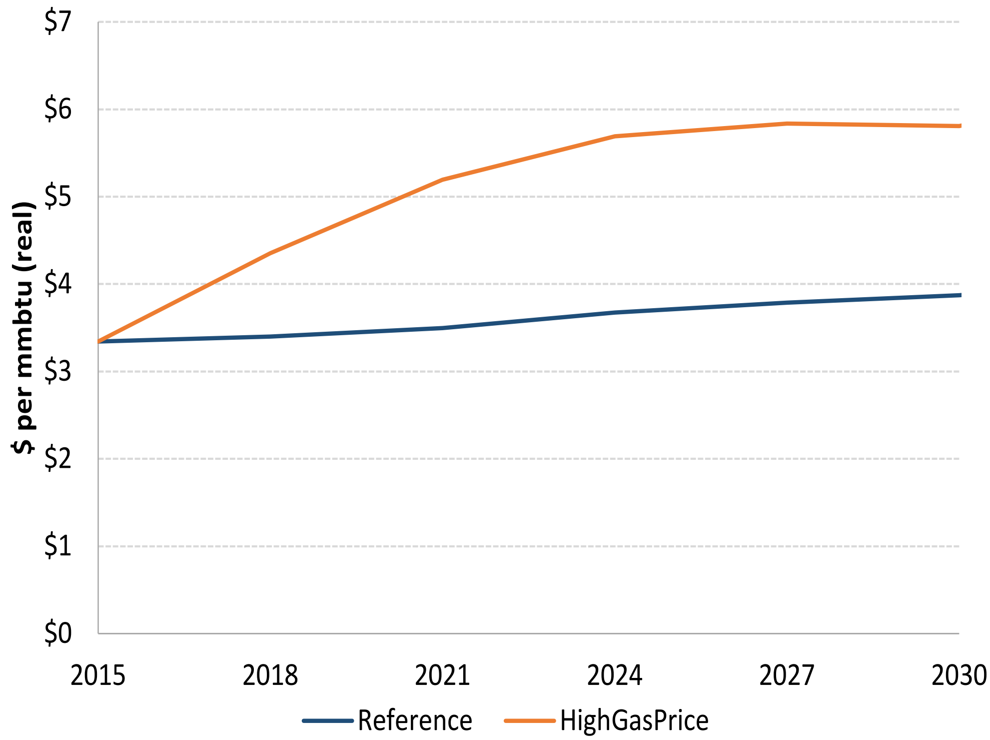

Figure 3-4
Assumed U.S. average power producers gas price paths in this analysis

Two coal retirement sensitivities were considered. The Reference Scenario combines announced retirements from ABB Velocity Suite, with suggested scenario retirement dates for remaining coal units provided by the Michigan utilities. The "AnnouncedRetire" scenario has a lower level of coal retirements, with all units assumed to continue generating through 2030 unless they have an explicit announced retirement date as noted in ABB Velocity Suite.[13] These two coal retirement sensitivities are depicted in Figure 3-5.

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[13] As noted above, the analysis for this report was completed before DTE's June 8, 2016 announcement of its intent to retire eight coal units at its River Rouge, Saint Clair, and Trenton facilities by 2023. These retirements are not included in the AnnouncedRetire scenario, but they are included in the Reference scenario.

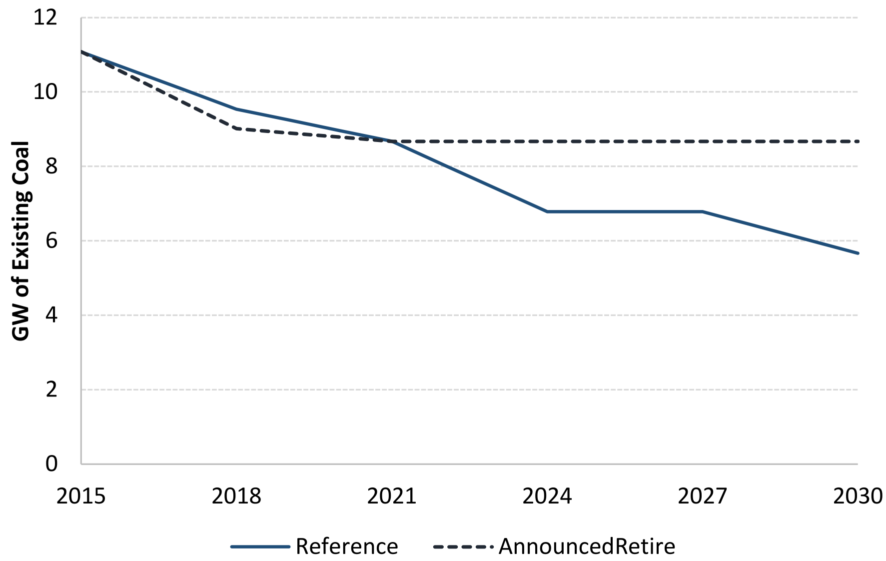


Figure 3-5
Assumed Michigan coal unit retirements in this analysis, by GW of summer capacity

These three sets of assumptions – Reference, HighGasPrice, AnnouncedRetire – drive very different investment decisions for Michigan in the respective 'No CPP' cases. Figure 3-6 shows capacity additions in Michigan from 2016-2030 in each of these three cases, assuming no CPP implementation.

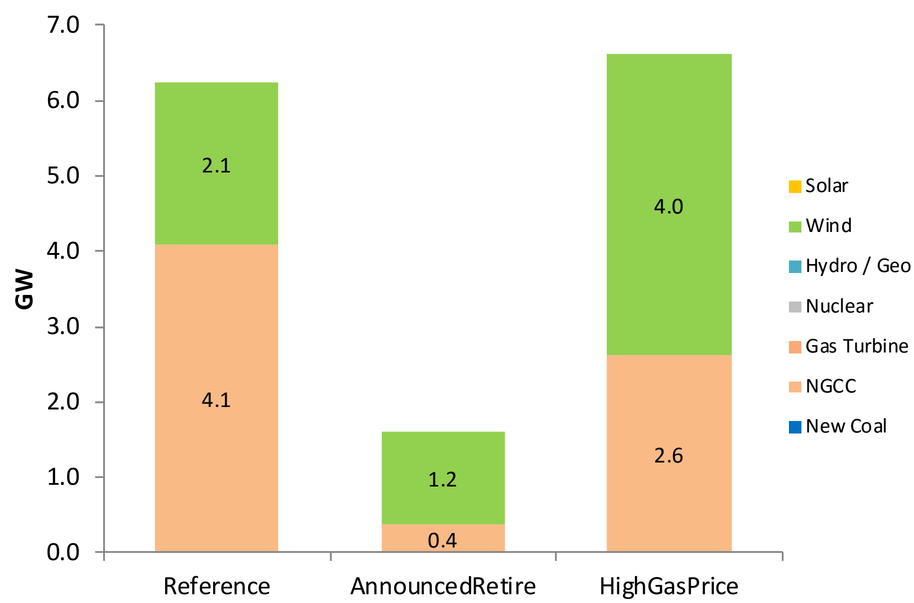
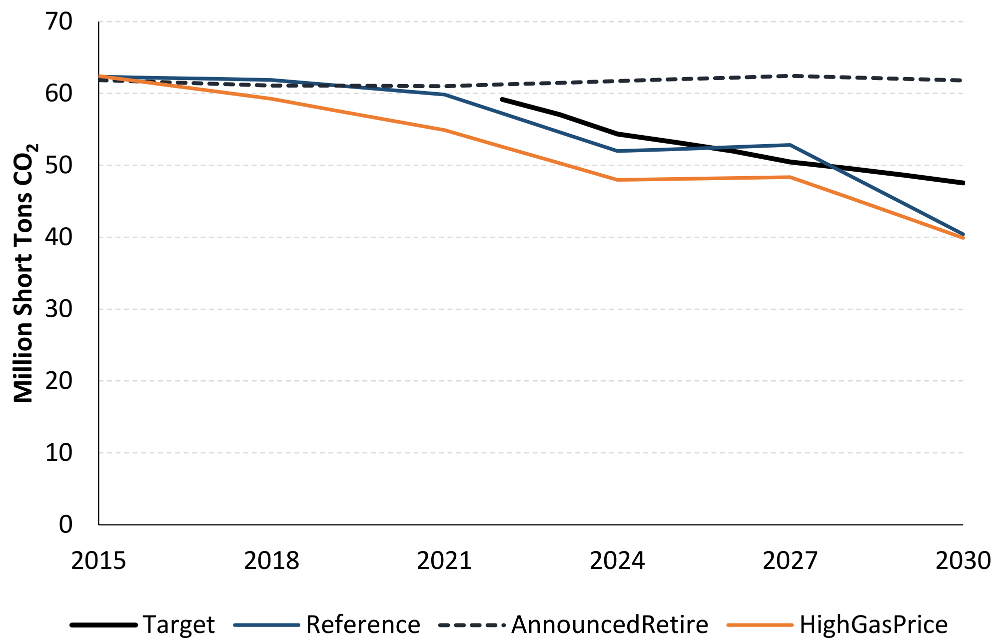


Figure 3-6
Capacity additions in Michigan between 2016-2030 under the three sets of sensitivity assumptions, assuming no CPP regulation.

Reference Scenario Compliance with Clean Power Plan Targets

The choice of reference assumptions can strongly influence whether a state would prefer mass or rate CPP targets based on a variety of metrics. As such, a useful starting point for an analysis of the Clean Power Plan is to determine how 'close' Michigan comes to complying with the various CPP targets in the reference case i.e. without forcing any specific changes to comply with the CPP. One metric for compliance with a mass target is to track CO_2 emissions from covered EGUs in short tons, and measure the difference from the state mass target, or state mass target + NSC. A metric for compliance with the performance rate target is to calculate ERCs demanded by covered EGUs under reference case output levels, calculate ERCs that could be created from in-state sources, and thence measure the difference between the two.



The reference case generation mix shows Michigan will meet Clean Power Plan mass targets in 2030, but is sensitive to assumed coal retirements.

Figure 3-7
Comparison of CO_2 emissions from affected units in Michigan under reference case sensitivities and EPA's CPP existing mass target

Figure 3-7 shows CO_2 emissions from affected EGUs in Michigan assuming no CPP. Three sensitivities are shown: Reference, a HighGasPrice, and AnnouncedRetire. Finally, the thick black line shows the CPP state mass target for Michigan. By 2030, emissions are about 8 million short tons (9mmt) below the target in the reference case, indicating the state of Michigan would be over-complying with the CPP mass target. However, the chart indicates that this result is very sensitive to the assumption of 'likely' coal retirements. Without those retirements, the emissions path is largely flat, as indicated by the dark blue dashed line. In this case, emissions from existing units exceed the target by around 14 million tons (15mmt) in 2030, implying that Michigan units would need to purchase 14 million short tons of allowances from out-of-state, or reduce emissions from existing fossil in-state, or take some mixture of both actions to achieve CPP compliance.

Figure 3-8 depicts a similar story when comparing CO_2 emissions from affected and new units in Michigan against the state mass target + NSC. 2030 CO_2 emissions are slightly above the state mass target + NSC, indicating that the mass + NSC target would be slightly more stringent in 2030 than the existing mass target. However, the NSC target would be less stringent in the earlier compliance periods, due to the higher cap and lack of new NGCC units built.

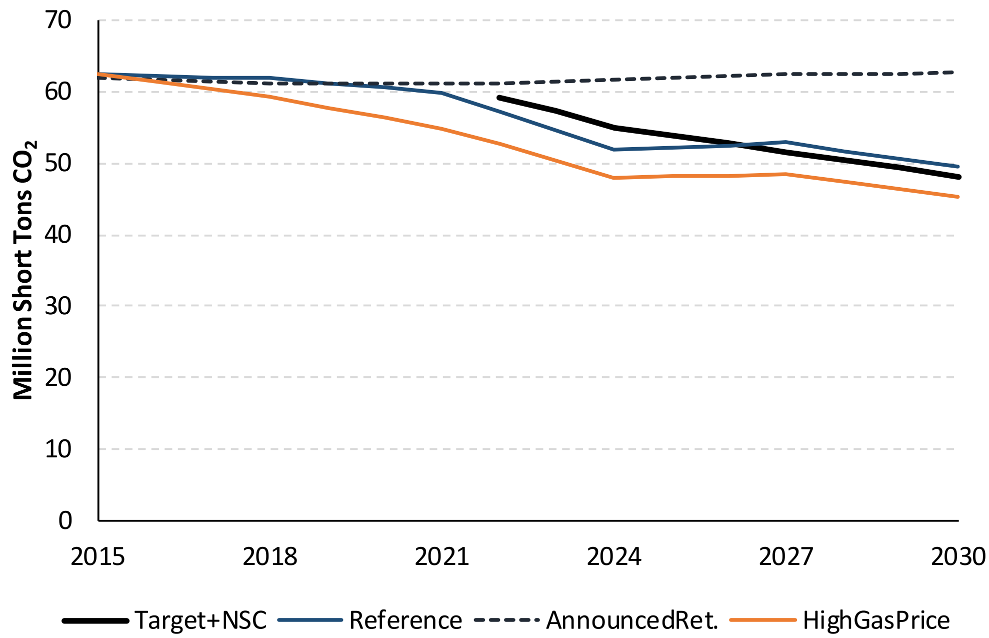


Figure 3-8
Comparison of CO_2 emissions from new and affected units in Michigan under reference case sensitivities and EPA's state mass target + NSC

Figure 3-9 shows the demand and supply of emission rate credits (ERCs). Demand represents the number of ERCs that (largely) coal units would be required to surrender if they were to run at reference levels under a performance-rate target. Supply represents ERCs generated if Michigan chose the performance rate-based pathway with only reference case actions. The fraction of wind from installed capacity after 2012 generates the most ERCs, followed by ERCs from legacy EE programs.[14] There would also be a smaller supply of

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[14] There is a great deal of uncertainty over how much additional energy efficiency will result from continuing existing energy efficiency measures, and furthermore how much of this energy efficiency will pass the verification requirements of the Clean Power Plan. This analysis assumes that 4.2TWh avoided energy demand per year can gain ERC credit for CPP rate compliance. The source of this number is discussed briefly in Appendix A.

ERCs from existing NGCC units (gas-shift ERCs), and nuclear uprates.[15] As the target rates tighten over time, supply of gas-shift ERCs falls, and demand for ERCs increases. Overall, under reference case assumptions, demand exceeds supply by 2030, but supply exceeds demand in prior compliance periods, largely because of the early boost in wind capacity incentivized by the Production Tax Credit.[16]

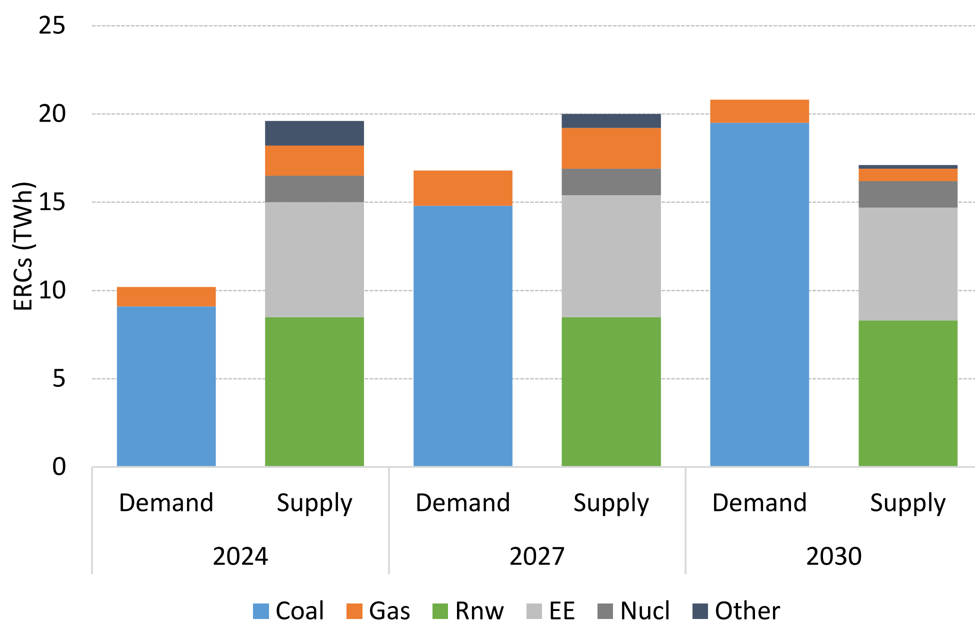

Figure 3-9
Demand and supply of emission rate credits in Michigan under reference case generation under CPP performance (unit) rate targets

Figure 3-9 indicates Michigan may face an ERC deficit by 2030 under reference assumptions, without additional compliance measures. Figure 3-10 indicates net ERC balances in both the reference case, and the two sensitivity cases. This shows that both the gas price path and the number of coal retirements are significant sensitivities for rate compliance in Michigan.

A high gas price path improves the net ERC position through to 2030. This is largely due to the high gas price path incentivizing additional wind capacity in Michigan, which in turn is able to create additional ERC supply to more than cover expected demand by the existing fossil fleet.

In comparison, lower coal retirements, as modeled in the AnnouncedRetire scenario, increases the demand for ERCs were Michigan to choose performance

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[15] There is additional uncertainty as to whether uprates at the Donald Cook nuclear units will go ahead or not. This analysis assumes they occur by 2020.

[16] Modeling of the production tax credit for wind is based on the language of the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301).

rate, resulting in a lower ERC balance. In this case Michigan would be short of ERCs from the second compliance period without additional compliance actions.

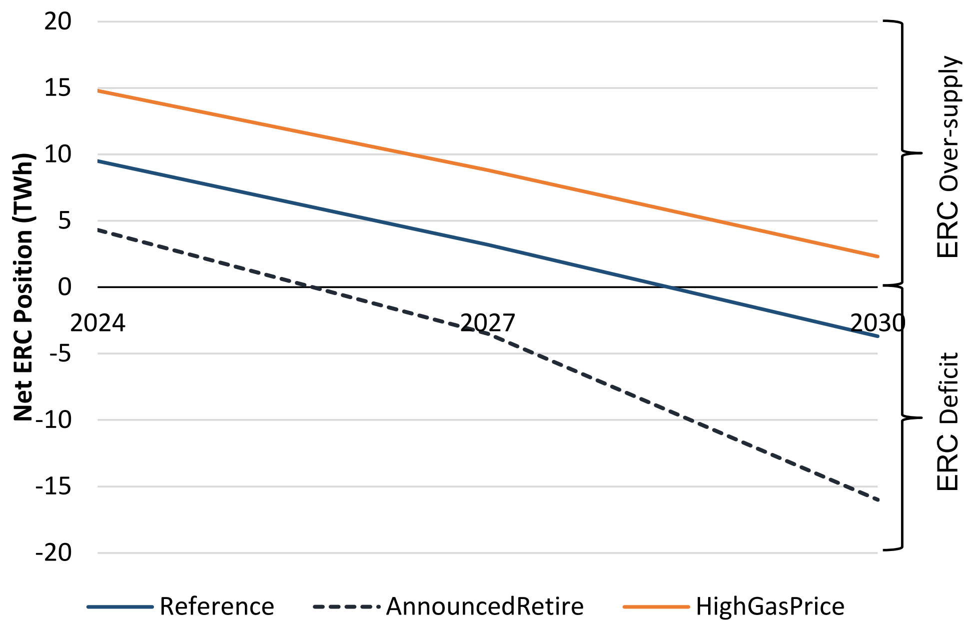


Figure 3-10
Net emission rate credit supply in Michigan for reference case sensitivities assuming CPP performance (unit) rate targets

Figure 3-7 through Figure 3-10 demonstrate that the number of coal unit retirements, and the gas price path, are key sensitivities driving Michigan's potential compliance with CPP rate or mass targets. If likely coal retirements do in fact materialize, then Michigan would be expected to largely be in compliance with the CPP state mass target by 2030. However, Michigan would not be expected to be in compliance with the rate target by 2030, even putting aside the uncertainties underlying ERC estimates for legacy energy efficiency and nuclear uprates.

To meet the CPP targets, Michigan may have to perform a combination of CO_2 mitigation measures, including, but not limited to:

- Reduce coal output
- Increase gas output from existing units
- Invest in alternative electricity sources such as new natural gas combined cycle (NGCC) units, new renewables, additional energy efficiency, or import more power from other states
- Utilize CPP market opportunities, i.e. purchasing CO_2 emissions allowances (if Michigan pursues a mass-based pathway) or ERCs (if a rate-based pathway is chosen)

Section 4: Clean Power Plan Compliance without Trading ("Island" Scenarios)

This section explores Clean Power Plan "island" compliance in Michigan. It explores least-cost state plans assuming the utilization of in-state compliance only with no trading of ERCs or CO_2 allowances. Although CPP compliance without trading is unrealistic for many states, these scenarios can be informative for decision-makers, modelers, and policy-makers for three reasons. First, this boundary scenario assesses resources and measures Michigan can take individually to comply with the CPP without relying on allowance or credit trading. These "island" scenarios provide a testbed for evaluating least-cost, in-state resources according to the US-REGEN model. Second, these scenarios elucidate Michigan's possible fallback options should it decide not to engage in trading. This worst-case scenario is a complement to the compliance scenarios with trading in Section 5 to understand a range of potential outcomes. Finally, these "island" scenarios provide a starting point for assessing the value of trade and sensitivities to technological and regulatory uncertainties.

Although Michigan is assumed not to trade CO_2 allowances or ERCs in this section, no additional restrictions on importing or exporting power to neighboring states are imposed beyond those in the reference case. Importing power is a potential mitigation option for any state looking to replace fossil generation for CPP compliance, so the assumptions on the CPP compliance pathways of the neighboring states matter. For this section, the CPP compliance pathways of the other 47 contiguous states are held fixed (although their least-cost compliance options may change as Michigan changes its own target). California is assumed to choose mass + NSC, and further not to trade CO_2 allowances with any other state. The RGGI states are assumed to choose mass + NSC, and to only trade allowances with other RGGI states. The three states building new nuclear units (Tennessee, South Carolina, Georgia) are assumed to choose performance rate, and to trade ERCs with each other. All remaining states, excluding Michigan, are assumed to choose existing mass and to trade with each other. This mix of state choices is denoted 'Mix A', and is represented graphically in the following figure.

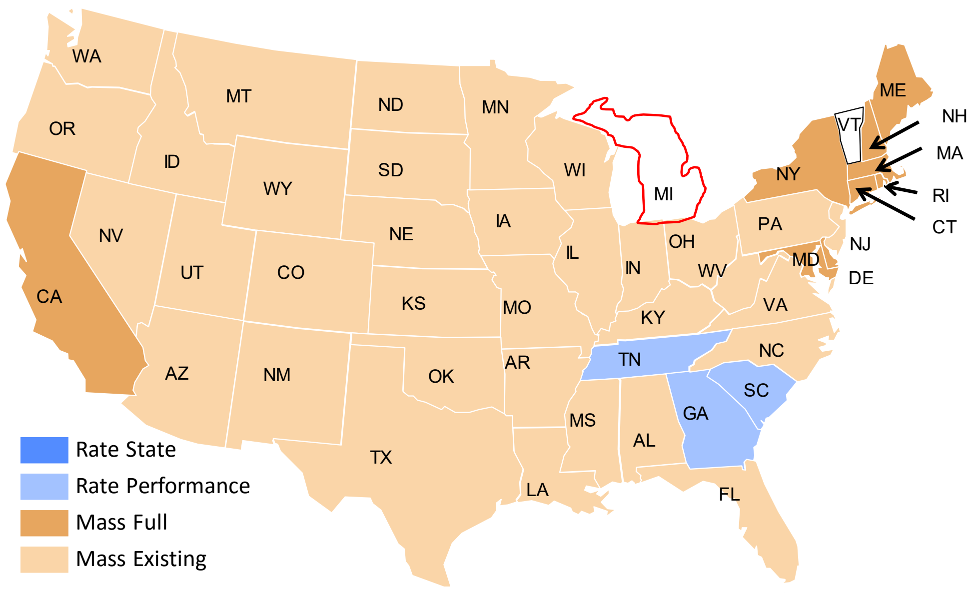


Figure 4-1
'Mix A' assumed CPP compliance pathway choices for all states excluding Michigan.

For Michigan and many other states, the mass-based CPP pathway relies more heavily on new NGCC investment, and the rate-based pathway more on wind.

The mix of state choices in 'Mix A' is not intended to be a prediction of what states might choose for CPP compliance, but represents some common assumptions in the energy press at the time of the analysis.

Results When Michigan Chooses a Mass Target

For the existing-mass target (Figure 4-2), Michigan is expected to be largely in compliance under reference assumptions. The only change is to bring forward 600MW of new NGCC investments from 2030 to the 2025-27 compliance period, to ensure the targets can be met in all of the interim compliance periods. The limited actions to achieve compliance imply the CO_2 price in Michigan is very low, less than $2/ton. This in turn implies that the output-based allowance allocations don't incentivize any additional wind capacity beyond the reference case – the implicit subsidy is too low to make wind competitive with new NGCCs given the assumed gas price path.

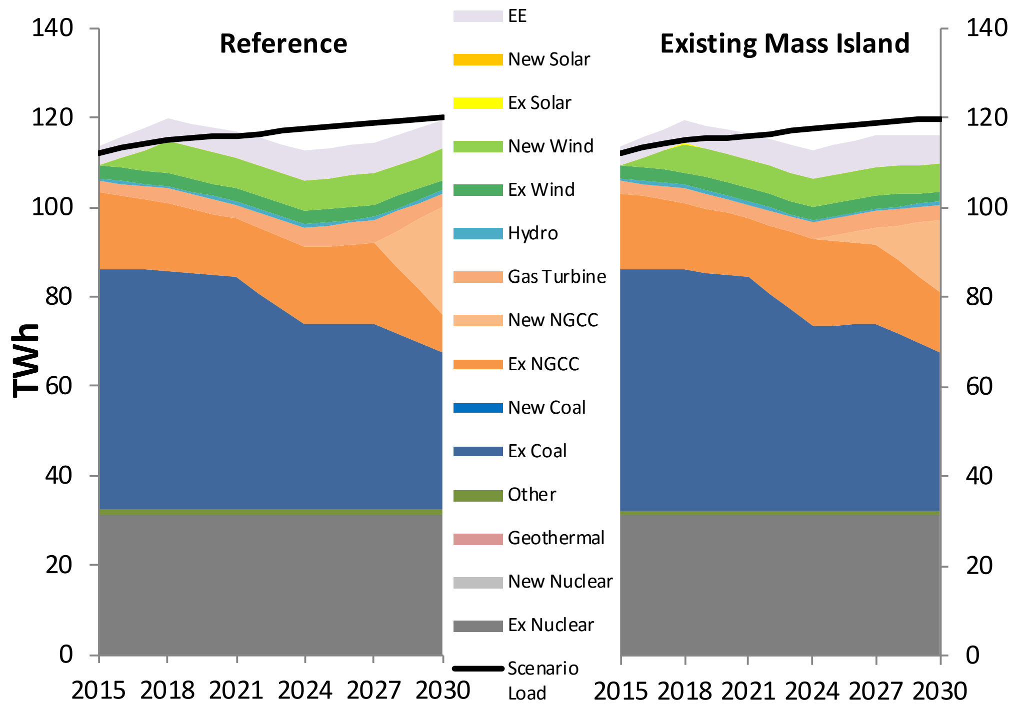


Figure 4-2
Electricity generation by technology in Michigan under reference (i.e., no CPP) and existing-mass island compliance scenarios

Figure 4-3 shows the equivalent chart for the case where Michigan chooses the mass target with the NSC, the sum of which caps emissions from both existing and new steam and NGCC units. Here, Michigan builds 800MW less new NGCC capacity, compared to compliance with the existing mass target, and replaces the lost power by running existing NGCC units harder, and importing more power from neighboring states. To enable the latter, amongst other changes, a 200MW NGCC unit is built in Indiana (Indiana is assumed to choose the existing mass target), and Michigan's transmission links with neighboring states are upgraded.

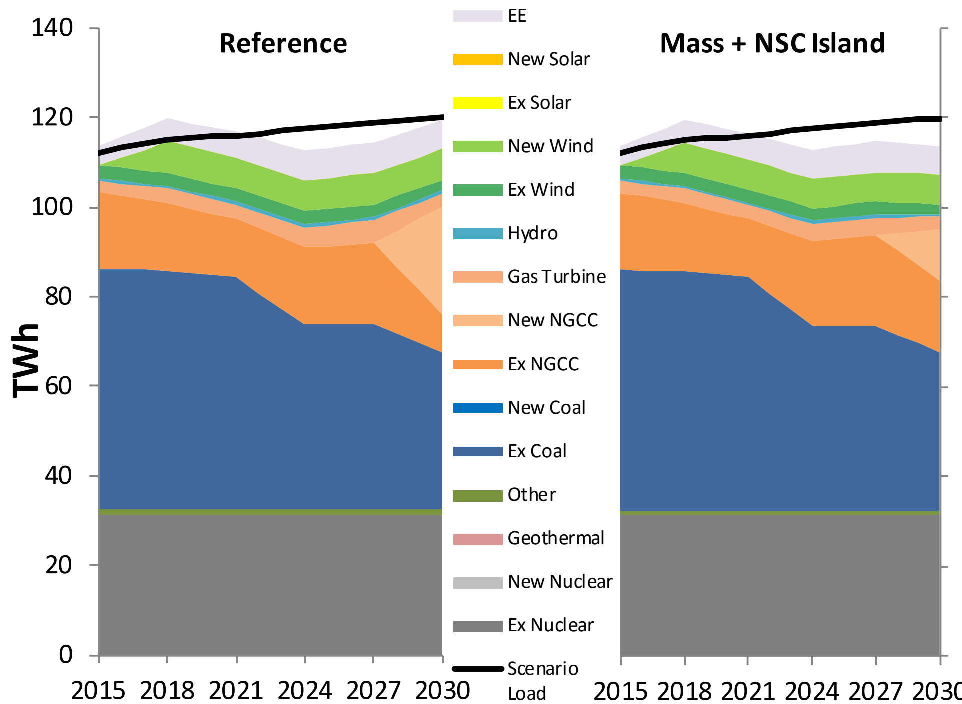


Figure 4-3
Electricity generation by technology in Michigan under reference (i.e., no CPP) and NSC mass island compliance scenarios

The next figure shows CO_2 allowance prices in Michigan under the existing mass target and the mass + NSC target respectively, under both reference and sensitivity assumptions. Prices are by far the highest in the scenario where likely coal retirements do not materialize. This reflects the marginal mitigation option of reducing coal generation, and replacing it mostly with new NGCC units. Under a high gas price path, combined with likely coal unit retirements, CO_2 allowance prices are zero, as the improved economics of wind over gas incentivize more new wind capacity in the respective reference case.

In any sensitivity, the CO_2 allowance price in other mass-based states (which are assumed to trade with each other) is higher than the Michigan price, indicating that Michigan has cheaper CO_2 abatement opportunities than the average of the other mass-based states. This in turn suggests that, if Michigan were to trade, it would be a net exporter of CO_2 allowances.

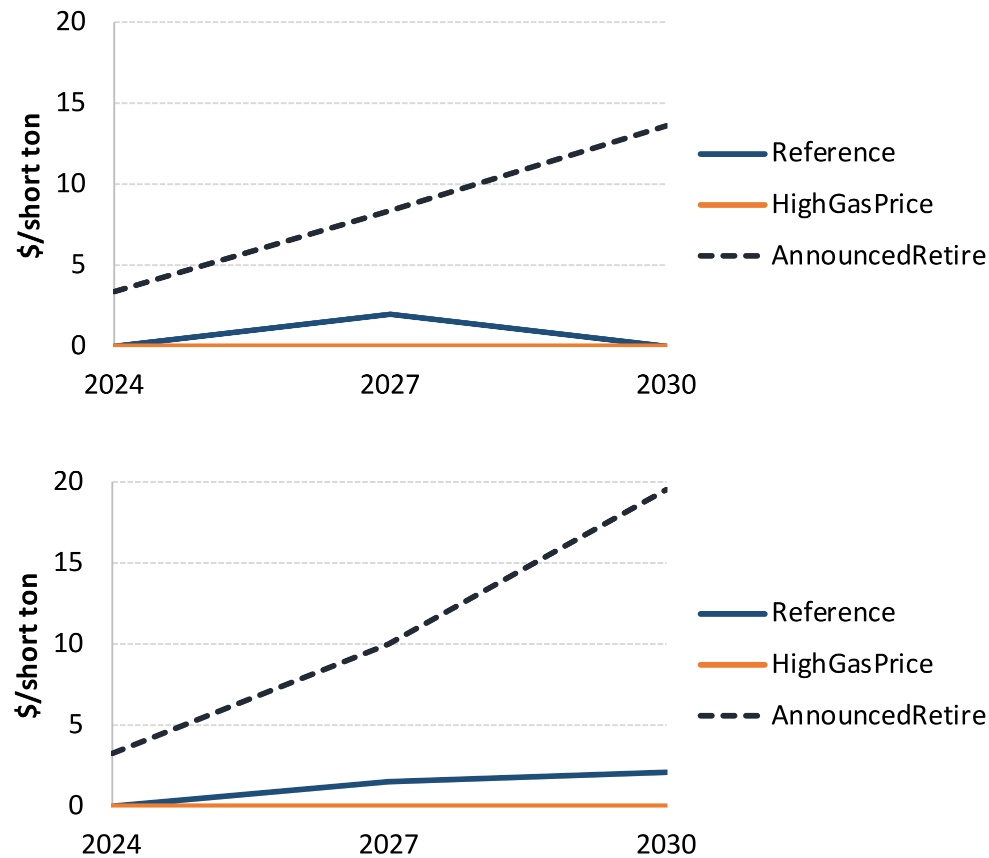


Figure 4-4
CO_2 prices in Michigan for the existing mass island scenario (top) and NSC mass island scenario (bottom)

Figure 4-2 to Figure 4-4 indicate that the announced coal retirements only sensitivity is by far the most significant for Michigan under a mass-based target. If only announced retirements occur by 2030, CPP mass compliance in Michigan would require substantial reductions in coal generation versus 2015, almost 30%, which is similar to the reductions that occur in the reference case with all the likely coal retirements. In other words, CPP mass compliance is relatively straightforward in the reference and high gas price path scenarios because the reduction in coal generation needed to meet CPP targets has already been assumed. Coal reductions by scenario are illustrated in Figure 4-7.

Results When Michigan Chooses the Performance Rate Target

For the performance rate island compliance pathway (Figure 4-5), the analysis suggests Michigan's cost-minimizing compliance strategy relies on additional wind deployment beyond that in the reference, approximately 800MW in the reference case, or up to 2GW in the announced retirements case. Under this strategy, ERCs from new wind would be surrendered by coal units, which allows much of the remaining coal fleet (after any assumed retirements) to keep operating through 2030.

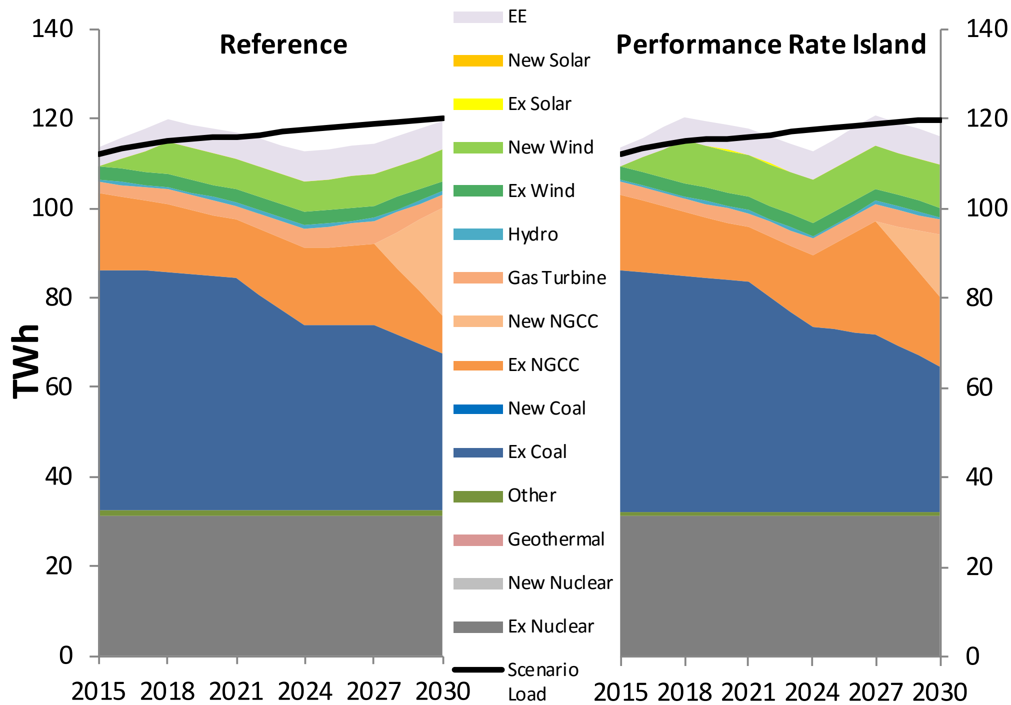


Figure 4-5
Electricity generation by technology in Michigan under reference (i.e., no CPP) and performance rate island compliance scenarios

Figure 4-6 gives the ERC prices, in $/MWh, that would drive the investments needed to comply with the performance rate target in Michigan. The price is driven by how much wind needs to be built relative to the reference, and how much coal generation falls relative to the reference. With a high gas price path, enough new wind is built for economic reasons to generate sufficient ERCs to keep the remaining coal units running as in the reference. But with only announced coal retirements occurring, the analysis suggests that the least-cost plan to comply with the performance rate target involves both building additional wind capacity and mothballing the least efficient coal units. Thus the price of ERCs is strongly dependent upon modeled assumptions.

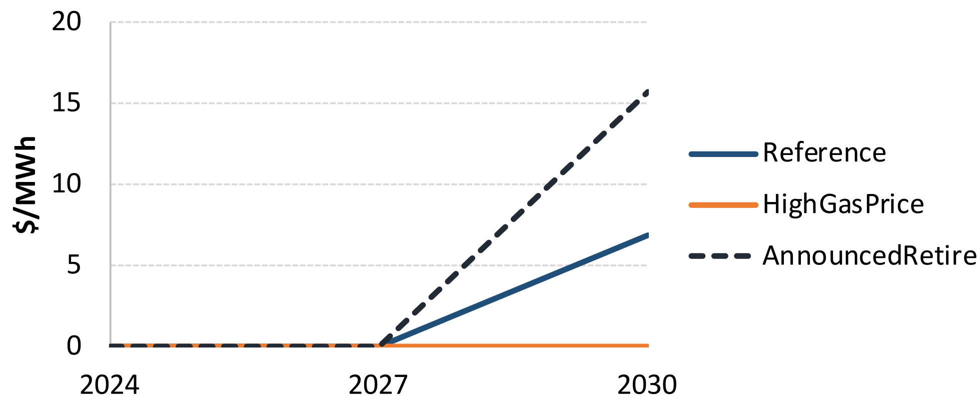


Figure 4-6
Emission Rate Credit (ERC) prices in Michigan for the performance rate island scenario

A quick rule of thumb for comparing the impact of CO_2 and ERC prices for a coal unit is to assume two ERCs equals one short ton of CO_2.

From the perspective of a coal unit, to generate an additional MWh, the unit would need to surrender roughly one short ton of CO_2 allowances under a mass target, or approximately one half of an ERC under a rate target. Thus a good rule of thumb for comparing CO_2 and ERC prices is to halve the ERC price to obtain an approximate equivalent CO_2 price.

The results above highlight the critical role of declining coal generation in meeting any potential CPP target in Michigan. Figure 4-7 depicts the percentage reduction in coal generation by 2030 vs. 2015 in various compliance scenarios. Under any mass target, coal generation declines by at least 28% between 2015 and 2030. It declines more in the reference and high gas price scenarios, but that is due to the level of coal unit retirements assumed, which in turn explains why Michigan would be expected to be largely in compliance with the mass target in these cases. If Michigan were to choose rate, coal generation could decline by as little as 9% for rate compliance, depending on the cost of new ERC-creating sources to support that coal generation versus the alternative of replacing the coal generation altogether.

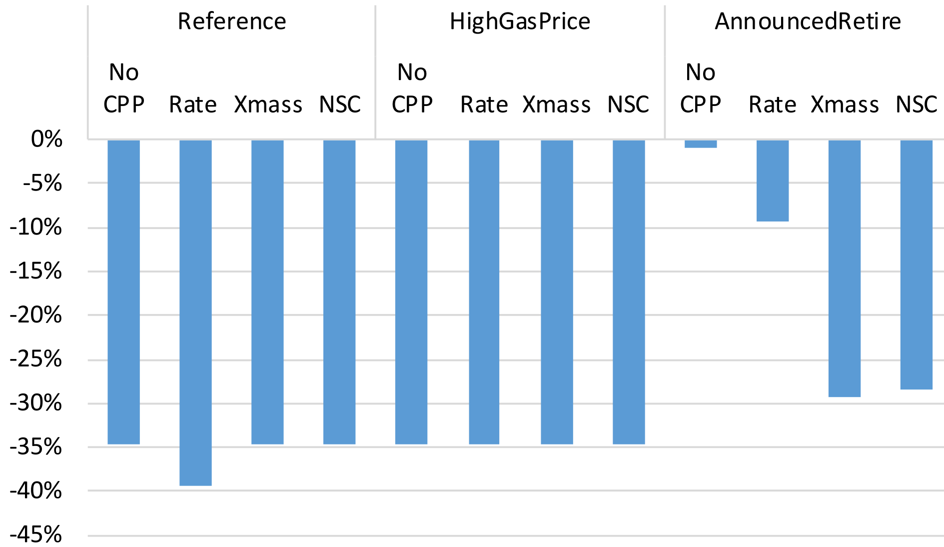


Figure 4-7
Decline in coal generation in Michigan by sensitivity and choice of CPP pathway

Most CPP compliance scenarios see Michigan reducing coal generation by ~30% in 2030 vs. 2015.

In summary, in an "island" compliance environment where Michigan must rely only on in-state resources without participating in trading markets, this analysis suggests that either of the CPP mass targets are lower cost than the performance rate pathway. In the reference case, the existing mass pathway requires bringing forward some NGCC investments, while the mass + NSC pathway requires importing more power and some low cost transmission upgrades. For the same case, the performance rate pathway requires 800MW of additional new wind, and more imported power with associated transmission upgrades. In Section 6, the additional costs due to the CPP are calculated for every modeled scenario, confirming the intuition that mass is expected to be consistently cheaper than rate for Michigan.

Section 5: Clean Power Plan Compliance with Inter-State Trading

Trading CO_2 allowances or emission rate credits may lower compliance costs, but comes at the expense of increased reliance on uncertain markets.

The compliance results in the previous section assumed Michigan relied solely on in-state compliance measures and did not participate in inter-state emissions trading, which is an option in the Clean Power Plan. Emissions trading—through allowances if Michigan selected a mass pathway and ERCs if Michigan selected rate—creates opportunities to lower overall compliance costs. National or regional markets for ERCs or CO_2 allowances are potential "backstop" options and strategic cost-containment mechanisms for CPP compliance. However, their size and depth are subject to significant uncertainty, and the use of these options creates potential tradeoffs between potentially lower costs (or lower price volatility) and reliance on markets.

This section seeks to:

- Understand how different "mixes" of compliance pathway selections in other states influence prices and market outcomes for Michigan
- Investigate the compliance balance between in-state investments and markets for allowances/ERCs
- Demonstrate opportunities to reduce cost, and understand the associated trade-offs.

Trading Mixes

If Michigan engages in trading with other states, the number and type of states choosing rate and mass is an important driver of the ERC and CO_2 prices respectively. With 47 states each choosing between six or more targets, plus whether or not to trade, there are a very large number of potential market outcomes. However, the key variable of interest to Michigan is the price, and so in this analysis two trading mixes were selected to provide some intuition as to potential outcomes from trading. These two mixes are represented in Figure 5-1. The first is the mix used for the Island analysis in the previous section, where most states choose existing mass and states building new nuclear units choose performance rate. This is henceforth referred to as Mix A. The second mix assumes that many states with good wind resource also choose rate, to take advantage of the low cost ERC supply, increasing the size of the ERC market and corresponding decreasing the size of the CO_2 allowance market. This is henceforth referred to as Mix B. Both mixes assume California and the Regional Greenhouse Gas Initiative (RGGI) states choose the full-mass pathway (i.e., Trading “mixes” represent potential developments of emission trading markets with alternate pathway selections for states.

with the NSC), that California does not trade with other states, and that the RGGI states trade only within RGGI.

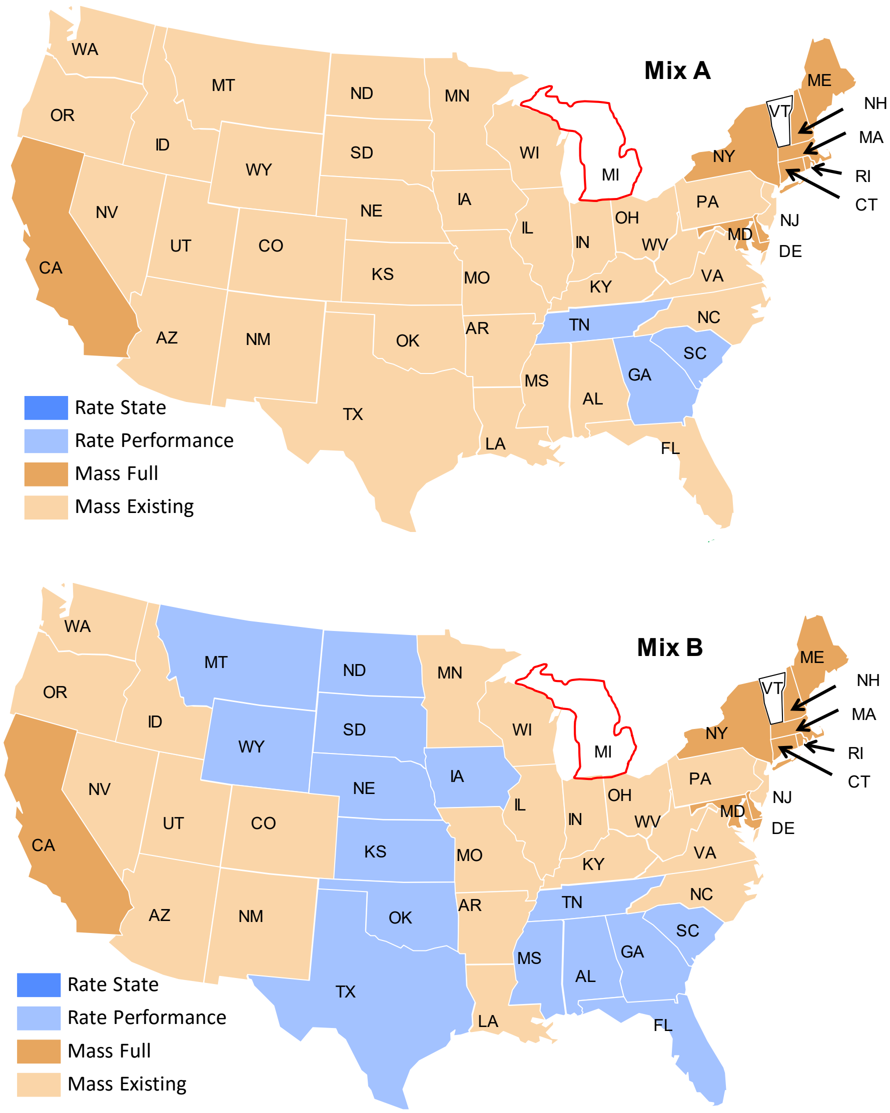


Figure 5-1
Clean Power Plan trading mix sensitivities considered in this analysis including Mix A (top) and Mix B (bottom)

It is not immediately obvious whether adding additional states to a rate-based trading market will increase or decrease market-clearing ERC prices. If additional states choose rate, additional ERC compliance obligations are expected to arise to compete for existing and new ERC supply resources. If states with low ERC demand and high ERC supply join a rate markets, the economic law of supply and demand suggests prices would fall (all else equal), whereas prices would rise if states with high ERC demand and low ERC supply join. These dynamics make it important to use modeling frameworks like US-REGEN to understand the implications of alternate pathway selections.

Outcomes if Michigan Chooses Existing Mass and Trades

Under reference assumptions, Michigan would have ~7 million short tons (8mmt) of excess CO_2 allowances by 2030, which could be sold onto the market. To put that into context, net demand from other mass-based trading states would be 127 million short tons (140mmt) in Mix A, and 89 million short tons (9mmt) in Mix B, again assuming reference assumptions. By comparison, if likely coal retirements did not occur, Michigan would be short ~14 million short tons (15mmt), and purchasing allowances could be an alternative to reducing in-state coal generation, depending upon the CO_2 allowance price.

Under the reference assumptions, the price of CO_2 allowances over time for Mix A and Mix B is depicted in Figure 5-2, assuming that Michigan chooses existing mass and trades. Despite Mix B having twelve fewer trading mass states than Mix A, the price paths are very similar under reference assumptions. This suggests the market for CO_2 allowances would be very deep, with many mitigation opportunities. However, the primary mitigation option would be to reduce coal generation in favor of NGCC generation, so it is not surprising that, under a higher gas price scenario, the analysis shows a larger gap between the price paths.

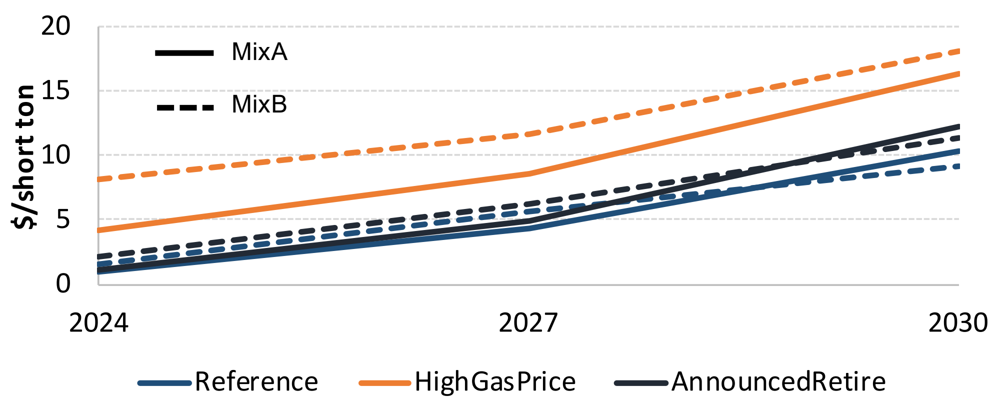


Figure 5-2
CO_2 allowance price paths by trading mix and sensitivity assumptions, assuming Michigan chooses the existing mass target

The age of Michigan's coal fleet relative to other states suggests that trading would incentivize additional reductions in coal generation in Michigan, to free up allowances to sell to other states.

Figure 5-2 depicts the 2030 CO_2 allowance price being in the range of $8-$12 per short ton under the reference assumptions. At this price, US-REGEN results suggest that not only would Michigan sell its excess 7 million short tons of allowances, but it would take additional mitigation measures to generate additional tons for sale to the market. These measures primarily comprise reducing existing coal generation; notably coal capacity factors would fall from 70% in the reference case to 50% in the trading scenario by 2030. This is an average; the least efficient units see the greatest capacity factor reductions while the most efficient units continue to operate as baseload. Michigan has a tranche of relatively old coal units compared to other mass-trading states, which are likely closer to retirement, and thus have lower opportunity costs from early retirement compared to newer units elsewhere. This result reflects the ability of trading to lower costs.

The above intuition applies even more forcefully to the announced retirements only scenario. Faced with a possible shortfall of 14 million short tons by 2030, the least cost compliance plan found by US-REGEN depends heavily on reducing in-state coal generation to cut 9 million short tons of CO_2, and purchases the balance of 5 million short tons on the market.

Outcomes if Michigan Chooses Performance Rate and Trades

Under reference assumptions, Michigan would be short ~4TWh of ERCs by 2030. To put that into context, net demand from other performance rate-based trading states would be 8TWh in Mix A, and 84TWh in Mix B, again assuming reference assumptions. Thus if there were few rate states, such as in Mix A, Michigan would be a significant player in the market, and its actions would drive the ERC price.

The ERC prices in the two mixes are depicted in Figure 5-3. Prices in Mix A tend to be notably lower under reference assumptions than under Mix B. This is because Mix A only has three rate states, all of whom have new nuclear units under construction which are expected to be a source of ERCs at no additional cost above the reference case. These three states do undertake some additional mitigation in the form of re-dispatching existing coal for existing NGCC units, but this is the only change beyond the reference, and the additional costs are very low. Under Mix B, there are many more rate states, who cumulatively demand far more ERCs than can be supplied by new nuclear units or coal to gas re-dispatching. Thus the ERC price rises to incentivize new wind capacity to supply additional ERCs. The exact price depends upon the quality of wind resource in the rate-based states. In the high gas price sensitivity, however, the high gas prices already provide enough incentive for new wind, so the ERC price is expected to be close to zero.

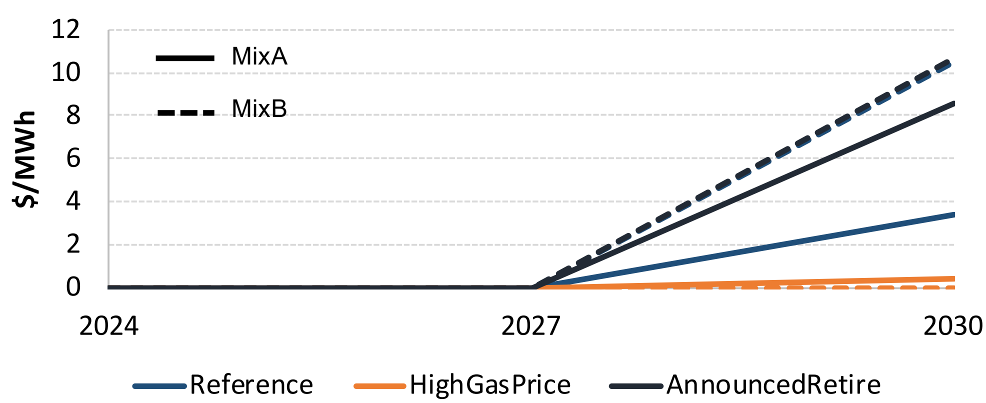


Figure 5-3
ERC price paths by trading mix and sensitivity assumptions, assuming Michigan chooses the performance rate target

The price of ERCs varies significantly across sensitivities, and the optimal strategy for Michigan changes in response to the price. At $3/MWh, Michigan would prefer to buy ERCs from out-of-state to meet its compliance obligations, if it were to choose the performance rate pathway. If the ERC price were $10/MWh, Michigan's least cost option would be to undertake more in-state mitigation measures, including building additional new wind capacity and maximizing the dispatch of the existing NGCC fleet in place of existing coal. The latter option also would generate GS-ERCs towards compliance, but would result in lower utilization of the more efficient new NGCC units, as these are not eligible to create GS-ERCs. Thus, Michigan's investment and dispatch decisions would rely heavily on the CPP target choices of other states, and the level of their participation in the ERC market.

Observations on CPP Trading for Michigan

Trading can lower the costs of both rate and mass compliance, as is enumerated in the following section. Yet there is reasonable concern over counting on yet-to-be formed markets as part of any compliance plan. It is also reasonable to be concerned over the risk of leaving CPP-driven investments stranded if markets develop with low prices. If likely coal retirements occur in Michigan, then Michigan will likely not need to make any compliance investments in the first compliance period, and can fine-tune investments in the second and third compliance periods. This would allow time to see how markets develop and react accordingly. If likely coal retirements do not occur, Michigan would need to make compliance decisions sooner, before seeing how the market developed.

Section 6: CPP Compliance Costs

One metric for comparing the range of Clean Power Plan sensitivities is the additional costs that would be incurred by Michigan's electric sector when the Clean Power Plan is implemented. The definition of electric sector costs used here includes

- All capital and operating costs
- Cost of new transmission (evenly apportioned between states on the line) plus maintenance
- Regulatory costs (e.g., alternative compliance payments for RPS, etc.)
- Cost of imported electricity, priced at the marginal wholesale price of the exporting state (minus the value of exported electricity)
- Net payments for Clean Power Plan credits/allowances

To enable comparisons across time, all costs are computed in present value (PV) terms to 2030, discounted back to 2010 at the US-REGEN discount rate of 5%.

The cost of the Clean Power Plan is then defined as the incremental electric sector costs to Michigan, beyond those incurred in the respective reference case without the Clean Power Plan.

Cost of Performance Rate Versus Existing Mass

Figure 6-1 demonstrates the additional costs that would be incurred by Michigan's electric sector under the Clean Power Plan if Michigan were to choose performance rate or existing mass respectively, with no trading of ERCs or allowances. Each point on the scatter plot represents one sensitivity. The vertical axis of this scatter plot is the cost to Michigan of choosing existing mass, and the horizontal axis is the cost to Michigan of choosing performance rate. The dotted line represents the set of points where the cost of choosing rate exactly equals the cost of choosing mass. Any point above this line is a scenario where choosing mass is more expensive than rate; any point below the line is a scenario where choosing rate is more expensive than choosing mass.

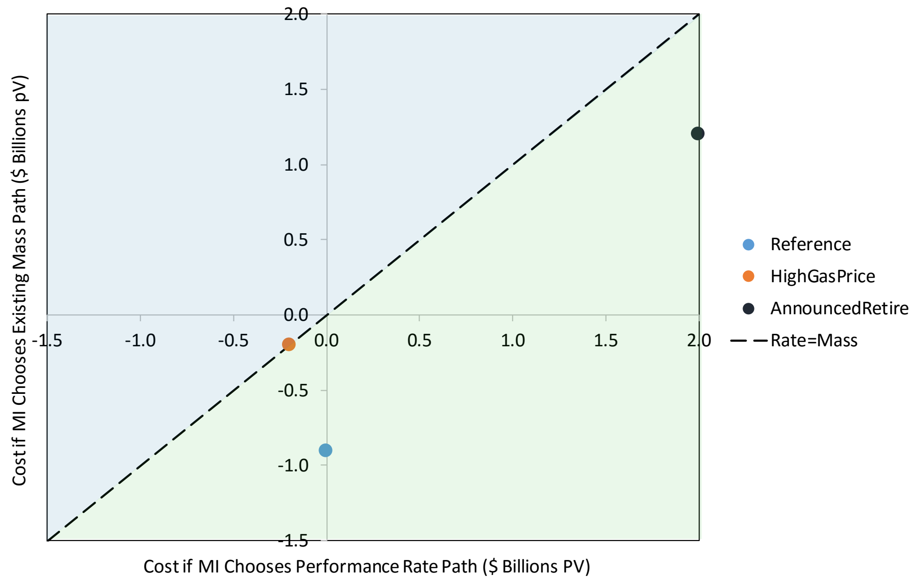
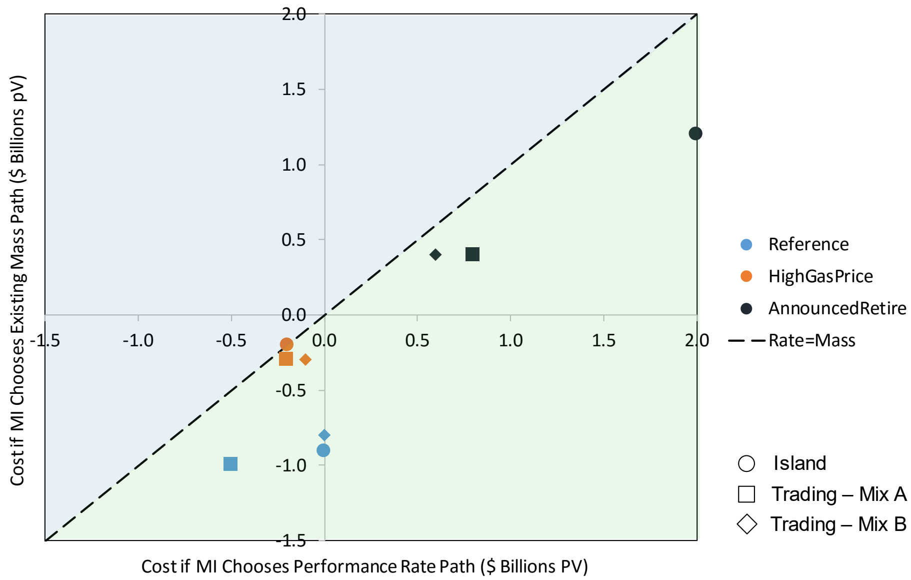


Figure 6-1
Additional costs in to Michigan's electric sector from implementing the CPP using the performance rate or existing mass pathways under no-trading (island) assumptions

Figure 6-1 reinforces some of the intuition developed in the previous sections. Under reference assumptions, mass is the lower cost choice, and indeed results in a gain to Michigan in the 2016-2030 timeframe, as the modeled price of electricity rises in other states. Under a high gas price path, there is no difference between choosing rate or mass – Michigan would essentially be in compliance with either target. If likely coal retirements do not materialize, then costs are expected to be significantly higher, yet the mass pathway would continue to be cheaper than the rate pathway.

Figure 6-1 covers the 'island' scenarios, scenarios where Michigan is assumed not to trade allowances or ERCs with other states. Figure 6-2 extends this to cover both island and trading scenarios, looking at the choice between the performance rate and existing mass pathways.



The cost to Michigan of complying with the existing mass pathway is expected to be less than for the performance rate pathway under all modeled sensitivities.

Figure 6-2
Additional costs to Michigan's electric sector from implementing the CPP using the performance rate or existing mass pathways under all modeled scenarios

Three types of trading regimes are represented in Figure 6-2, paired with the three key sensitivities modeled. Three insights are clearly evident in this figure:

- Trading reduces the cost of complying with the CPP. This is evidenced by the circle points representing no-trading scenarios lying above and to the right of the square and diamond points representing trading scenarios. The gains from trading vary by scenario. Under the high gas price sensitivity, there is very little gain to trading, whereas under the announced coal retirements only scenario, trading can reduce costs by over a billion dollars PV.
- The two different state pathway mixes modeled – Mix A (mostly mass) and Mix B (mixed mass and rate) – don't drastically alter the compliance costs for Michigan, as seen by the close proximity of the square and diamond points. The biggest difference occurs under reference assumptions if Michigan chooses rate. In this case the difference between Mix A and Mix B is the difference between Michigan purchasing ERCs versus investing in in-state mitigation options, as was described in the previous section.
- Most importantly, all points lie below the 45-degree line. This demonstrates that the existing mass pathway is cheaper than the performance rate pathway under any sensitivity or trading scenario.

Cost of Performance Rate Versus Mass + NSC

Finally, Figure 6-3 recreates a similar scatter plot to compare performance rate and the mass + NSC pathways. The result is qualitatively very similar to the comparison with the existing mass pathway. Under any scenario, the mass + NSC pathway is a lower cost compliance pathway than performance rate. A comparison of Figure 6-2 and Figure 6-3 also reveals that the mass + NSC pathway is slightly cheaper than the existing mass pathway; however, this result should be treated with caution. It is a result of the mass + NSC pathway having a slightly higher cap, combined with the model anticipating very little new gas being built in Michigan before 2030. Furthermore, this modeling assumes that some of the new gas is moved to neighboring states that choose the existing mass or performance rate path, and the power is imported back into Michigan. Were Michigan planning significant new investments in NGCC units through or beyond 2030, then the mass + NSC pathway would be more expensive than the existing mass pathway.

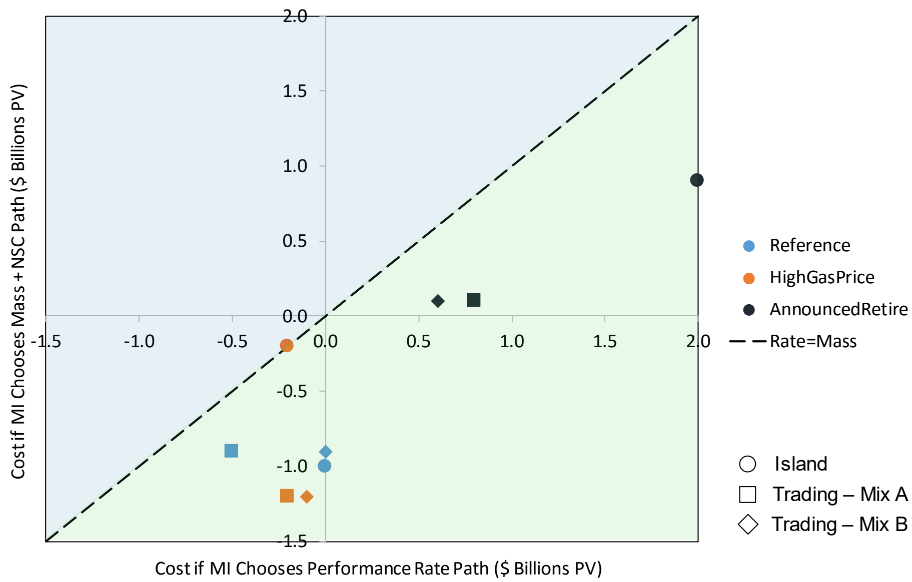


Figure 6-3
Additional costs to Michigan's electric sector from implementing the CPP using the performance rate or mass + NSC pathways under all modeled scenarios

Summary

The costs under the reference assumptions presented in this section are unequivocal. Under all modeled scenarios, with or without trading, Michigan is always better off on a present value cost metric choosing a mass-based compliance pathway over the performance rate pathway. This conclusion holds despite optimistic assumptions on the amount of legacy energy efficiency that could gain ERC credit and on the cost to deploy new renewables in Michigan. Fundamentally, this result reflects the reality that Michigan is likely to retire and replace much of its coal fleet; a reality that should go a long way to meeting the CPP mass targets. On the other hand, a rate target would require Michigan to find new sources of ERCs, and that requires additional investments or ERC purchases above and beyond the expected coal unit retirements.

Section 7: Summary

This analysis focused on understanding state-level Clean Power Plan (CPP) choices for Michigan. Specifically, the analysis assessed performance rate, existing mass, and mass + new source complement (NSC) pathways with and without market participation under key sensitivities.

EPRI's US-REGEN model was used to compare CPP compliance results to an appropriate reference scenario (i.e., without the CPP) to understand tradeoffs between Michigan's planning options. In addition to rate and mass pathways, the analysis considered alternate trading scenarios to understand how reliance on in-state measures versus participation in inter-state emissions trading markets influence outcomes.

Michigan likely faces numerous fossil unit retirements over the next fifteen years, and thus will need to plan for new generation investments regardless of the Clean Power Plan. Because the reference scenario already assumes these retirements, and thus the substantial new investments to replace the power from those units, additional costs to comply with the Clean Power Plan are expected to be relatively low in most scenarios. Michigan's CPP choices would serve mainly to influence the types of new investments made, rather than requiring additional investments. Indeed, under the reference assumptions, Michigan is expected to be largely in compliance with the existing mass target by 2030, and close to compliance with the mass + NSC target by 2030, whereas complying with the performance rate target would require additional wind capacity or ERC purchases to close the compliance gap.

Key Takeaway 1: Either mass-based Clean Power Plan pathway would be lower cost for Michigan than the performance rate pathway. This conclusion holds across all modeled sensitivities.

The analysis suggests that the state mass target applied to existing EGUs would be an attractive CPP compliance pathway for Michigan. This pathway is lower cost than the performance rate path due to the large number of coal unit retirements expected in Michigan before 2030. Furthermore, compliance can be potentially achieved cheaply by in-state actions, and does not rely on the development of trading markets. This conclusion holds across all modeled sensitivities and trading assumptions, including high natural gas prices and fewer coal unit retirements.

The primary elements of CPP compliance strategies for Michigan include:

- Reducing coal in-state generation through retirements and/or lower utilization
- Building new wind capacity to comply (under a rate pathway)

- Trading CO_2 allowances or emission rate credits if mass- or rate-based pathways are chosen, respectively

If Michigan were to choose a mass-based pathway, it would likely have surplus CO_2 allowances to sell into the market. This analysis suggests the market for allowances is relatively deep.

Key Takeaway 2: Least cost CPP compliance in Michigan can require ~30% reduction in coal generation by 2030 vs. 2015.

The key metric driving compliance costs for Michigan was the reduction in coal generation driven by pre-planned retirements versus that driven by CPP compliance. Analysis of all but one of the 27 CPP compliance scenarios modeled saw Michigan's coal generation decline ~30% by 2030 versus 2015. If these retirements were assumed in the reference case, then compliance costs were found to be minimal. If these retirements were not assumed in the reference case, then the least cost path to compliance under the EPRI analysis required a similar cut in coal generation in all but one scenario (Figure 4-7). Indeed, in many scenarios in this analysis, adding the ability to trade caused greater declines in coal generation in Michigan, due to the relative age of Michigan's coal fleet versus that of other states.

Factors beyond cost also favor a mass-based pathway selection for Michigan, including:

- **Self-Reliance:** Michigan could possibly comply with the CPP through a mass pathway by relying on coal unit retirements expected by 2030 to meet the state mass target. While this requires investments to replace the coal generation, these are already anticipated regardless of the CPP. Crucially, this does not rely on the development of an uncertain market for compliance.
- **Volatility in compliance strategies:** Model results suggest that Michigan's least cost strategy for complying with the performance rate pathway would depend upon the evolution of the market for ERCs. If Michigan invests in new wind capacity to comply with a rate target, and the market subsequently develops with very low prices such as in Mix A, those investments could potentially be stranded.

The flexible compliance options states can adopt under the CPP makes decision-making more complex, requiring state-of-the-art optimization and economic modeling tools to understand tradeoffs and impacts. Regional heterogeneity means that there is not a dominant approach for all states, and the interdependence of states actions (which are affected by actions elsewhere) means that decisions must be evaluated simultaneously. The US-REGEN framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets. This analysis suggests that representing market interactions for electricity, CO_2 allowances, and emission rate credits is important in assessing economic impacts and compliance alternatives of policies like the CPP.

Although this analysis offers valuable insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for

Michigan, or legal advice on how Michigan can comply with the CPP.[17] It can be expected that each state's preferred portfolio of compliance measures (e.g., in-state actions and market participation) will be informed by a range of factors, including in-state compliance costs, risk tolerance, local incentives, and assumptions about market liquidity and participation. Likewise, actual deployment will depend on additional factors (e.g., policy, judicial outcomes, permitting, and uncertainty) that fall outside of the scope of this economic modeling and analysis.

[17] For instance, US-REGEN does not include all costs incurred by coal units as they age (e.g., unit commitment constraints are not included in this version of the model). Including such costs could influence retirements.

Appendix A: US-REGEN Model Description and Key Assumptions

The U.S. Regional Economy, Greenhouse Gas, and Energy (**US-REGEN**) model was developed by the Electric Power Research Institute.[18] The model combines detailed capacity planning and dispatch of the power sector for the Lower 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the economy.[19] The two models are solved iteratively to allow policy impacts on the electric sector to account for economic responses (and vice versa), which means US-REGEN can assess a wide range of energy and environmental policies.

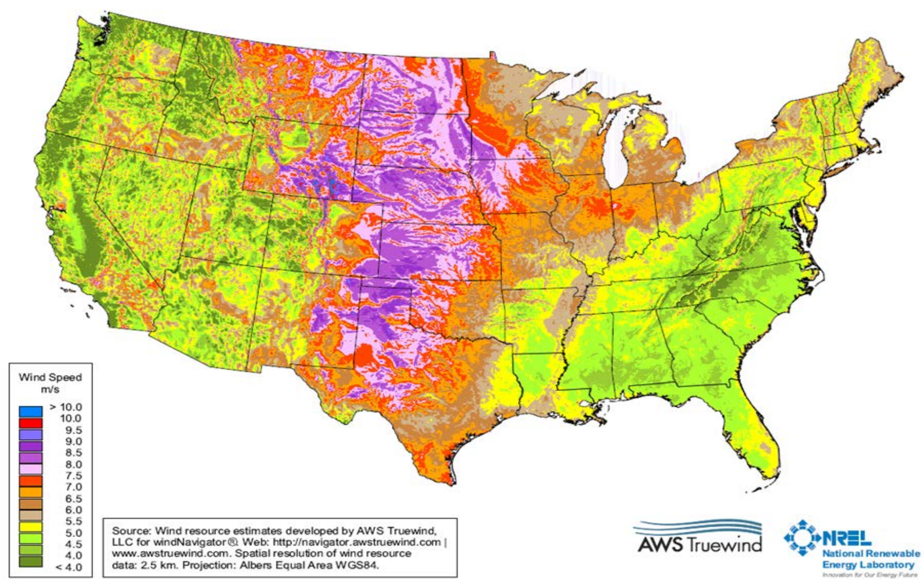


Figure A-1
Location of wind resources by state in US-REGEN

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[18] Additional detail can be found in *US-REGEN Model Documentation 2014*, EPRI Technical Update #3002004693 (available online at http://eea.epri.com/models.html).

[19] The CGE model of the U.S. economy includes representations of the residential, commercial, industrial, transportation, and fuels processing sectors.

The analysis in this report uses the electric-sector model only to analyze the Clean Power Plan. The model contains added detail to simultaneously capture capacity investment (including co-optimized transmission) and dispatch decisions for all 48 states in the contiguous United States. The forward-looking, long-term capacity planning model optimizes investments through 2050 to find the least cost way to meet load. Customizable regions and time-steps can be tailored to the needs of specific research questions. For all Clean Power Plan analyses, the model uses three-year time-steps through 2030 and five-year steps between 2030 and 2050.

The model simultaneously determines a cost-minimizing solution for all 48 states subject to technical and policy-related constraints. US-REGEN's spatial and temporal detail ensure resource adequacy for each state and capture market dynamics not only for electricity but also for CPP-related trading of allowances (for mass-complying states) and emission rate credits (for rate-complying states).

Hourly renewable resource data come from AWS Truepower and provide synchronous time-series values with load. The onshore wind resource was modified for Michigan in this study to make use of resource data from the Michigan Wind Resource Study (2009).[20] Figure A-1 illustrates wind resource data in the Lower 48 U.S. states represented in the model, and Figure A-2 shows the wind resource potential assumed for Michigan, assuming 80/100-meter hub heights. The joint variability of load, wind, and solar in this analysis is based on meteorology from 2010.

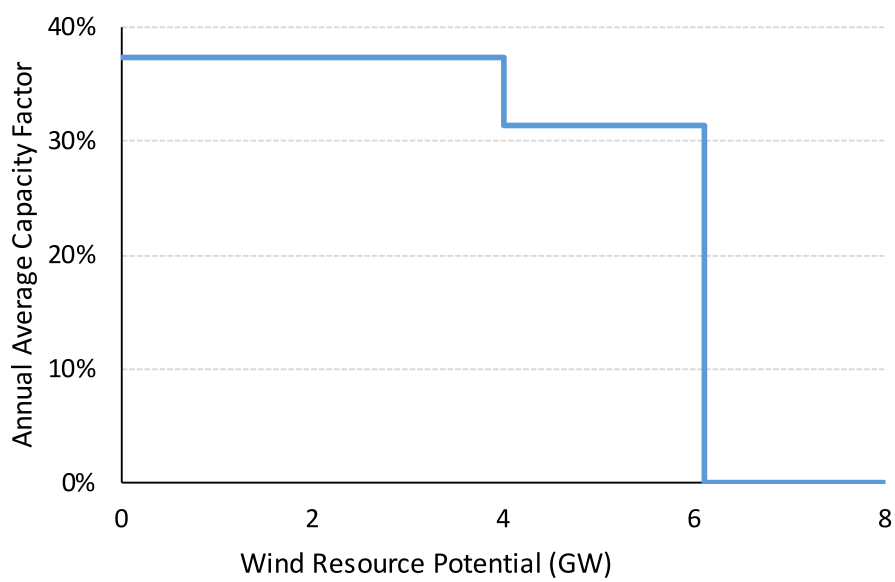

Figure A-2
Onshore wind resource potential (MW) assumed in Michigan by capacity factor (%)

[20] Available at www.dleg.state.mi.us/mpsc/renewables/windboard/werzb_final_report.pdf

US-REGEN employs an innovative algorithm to capture the hourly joint variability of load, wind, and solar profiles in a long time horizon model. This algorithm selects "representative hours" to preserve key distributional requirements for regional time-series data with a two-orders-of-magnitude reduction in dimensionality. This procedure provides between 50 and 100 intra-annual segments for system dispatch and load balancing in each annual timestep. This approach significantly outperforms simple heuristic selection procedures that focus on representing the load duration curve at the expense of other renewable time-series data. Figure A-3 compares how US-REGEN's "representative hour" approach compares to the "seasonal average" approach.

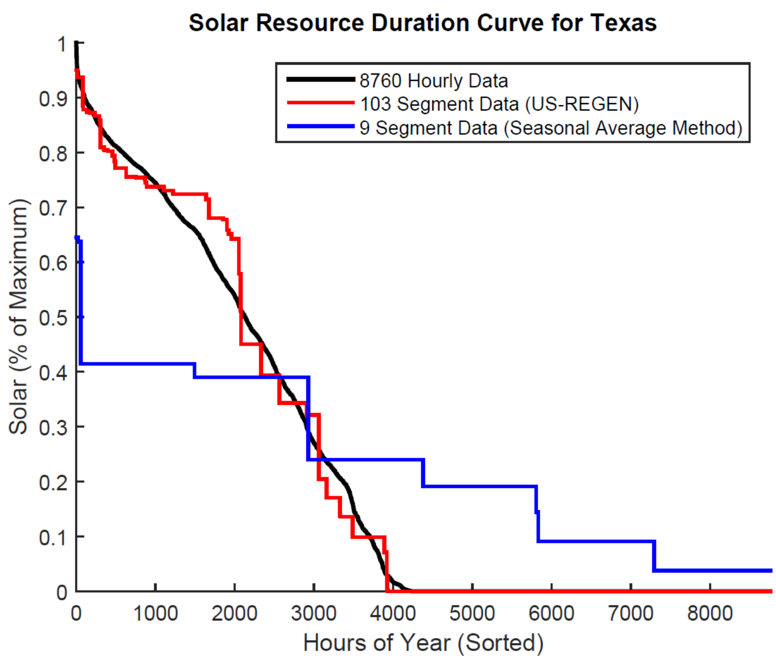

Figure A-3
Comparison of US-REGEN's representative-hour algorithm output (red) for the solar resource duration curve comparison for Texas with the underlying hourly data (black) and the seasonal-average approach (blue)

US-REGEN models a wide range of CPP compliance options in the power sector, including endogenous heat rate improvements, endogenous energy efficiency, detailed renewable resource representations, re-dispatch, options for existing coal (e.g., co-firing, conversion to gas or biomass, CCS retrofits), and many others.

While US-REGEN is able to model all 48 states' CPP decisions simultaneously from 2015-2050, this does require computation trade-offs. US-REGEN does not capture the breadth of detail within a state or RTO that a production cost model could. For example, US-REGEN:

- Does not consider unit commitment constraints. Units are dispatched on short-run cost.

- Does not consider transmission constraints within a state, and inter-state transmission is represented by pipeline flows.
- Does not include explicit representation of gas distribution to power units.

For this analysis, a representation of energy efficiency savings from existing measures was computed, using data from EIA Form 861. The avoided MWh from these programs are assumed to be already built into the AEO load growth forecasts, however, potentially new energy efficiency from these programs could be used for ERC credit towards CPP rate compliance. For each state with reported existing measures, the new EE savings from 2011-2014 were averaged, and the result used to represent one estimate of how much energy efficiency could be used for CPP compliance annually. For Michigan, this was 4.2TWh per year in all scenarios. This "legacy energy efficiency" is distinct from new energy efficiency measures, which in this analysis were assumed to cost $550 per first year MWh, with avoided MWh savings declining linearly to zero over a twenty-year period. These numbers were based on EPA's proposed Clean Power Plan assumptions, and works out to $55 per MWh avoided. The US-REGEN model has the option to select this new energy efficiency to help meet load if it is part of the lowest cost solution to do so. Any deployment of new energy efficiency directly reduces load growth.

The reference scenario assumptions are detailed in Section 3. All scenarios use fuel prices from the 2015 Annual Energy Outlook (EIA, 2015). The natural gas price trajectory comes from the 2015 AEO high estimated ultimate recovery (HEUR) case. EPRI technology costs and limitations (e.g., on the rate and extent of transmission and nuclear deployment) are used. Technology cost and performance assumptions come from the most recent EPRI Integrated Generation Technology Options report. In line with AEO 2015 assumptions, there are no forced retirements for existing coal units in the reference case, though retirements for economic reasons are possible in any period.

The reference (i.e., no CPP) scenario includes most existing and known future state and federal policies and regulations. Updated state renewable portfolio standards are included along with federal policies like MATS and CWA § 316(b). Other state policies include California's AB 32 and the Regional Greenhouse Gas Initiative (RGGI) for eastern states. The Clean Air Act § 111(b) CO_2 performance standards are included in the analysis. 2015 tax extenders for wind or solar are included in the analysis. Rooftop solar is modeled as a separate technology "behind the meter" (i.e., rooftop generation receives the retail price for electricity) in California.

A list of key model assumptions can be found in Table A-1.

Table A-1
Key Michigan-specific assumptions used in this report

Assumption	Michigan Value(s)	Source
1 Choice of Electric Sector Model[21]	US-REGEN, Economic model with Capacity Expansion	EPRI
2 Analysis Period	2015-2050	
3 Model Regions	All lower 48 states	
4 Discount Rate	5%	
5 Load Growth	1.005% per year through 2030 (after accounting for legacy EE programs)	EIA AEO 2015 Reference Case
6 Unit Retirements *(in MW)*	Announced retirements (2410 by 2030) Likely retirements (5450 by 2030)	ABB Energy Velocity MI Utilities Staff
7 Renewable Installed Capacity[22] *(in MW in 2015)*	Onshore Wind: 1360 Offshore Wind: 0 Utility PV: 3.5 Rooftop PV: 27	EIA Electricity Monthly, as of Nov. 2015
8 Natural Gas Price[23] *(in 2010 real dollars/mmbtu)*	$3.40 in 2016 to $3.87 in 2030	EIA AEO 2015 High Economic Ultimate Recovery Case
9 Coal Price *(in 2010 real dollars/mmbtu)*	$2.21 in 2016 to $2.28 in 2030	EIA AEO 2015 High Economic Ultimate Recovery Case
10 Fuel Oil Price *(in 2010 real dollars/mmbtu)*	$12.73 in 2016 to $13.06 in 2030	EIA AEO 2015 High Economic Ultimate Recovery Case
11 Natural Gas Combined Cycle Capital Costs *(in 2010 real dollars/kW)*	$1230 from 2016 to 2030.	EPRI TAG Program

[21] US-REGEN documentation available at http://eea.epri.com/models.html .

[22] The EPRI-MI CPP analysis does not count 100% biomass fired units as renewables under the Clean Power Plan, due to the uncertainty around the accounting of life-cycle CO_2 emissions.

[23] This is the national average fuel price. Individual units have adders, based upon data provided by ABB Energy Velocity.

Table A-1 (continued)
Key Michigan-specific assumptions used in this report

Assumption	Michigan Value(s)	Source
12 Natural Gas Combined Cycle Heatrates *(in mmbtu/MWh)*	6893 in 2016 down to 6319 in 2030.	
13 Natural Gas Combined Cycle Fixed O&M Costs *(in 2010 real dollars/kW)*	$17	EPRI TAG Program
14 Natural Gas Combined Cycle Variable O&M Costs *(in 2010 real dollars/MWh)*	$2.40	EPRI TAG Program
15 Renewable Capital Costs *(in 2010 real dollars/kW)*	Onshore Wind: $1974 in 2016 down to $1699 in 2030. Offshore Wind: $3542 in 2016 down to $2985 in 2030. Utility PV: $1742 in 2016 down to $1439 in 2030. Rooftop PV: $2188 in 2016 down to $1568 in 2030. These costs include $450/kW adder for new transmission and distribution upgrades.	EPRI TAG Program
16 Renewable Fixed O&M Costs *(in 2010 real dollars/kW)*	Onshore Wind: $39 Offshore Wind: $104 Utility PV: $25 Rooftop PV: $25	EPRI TAG Program
17 Renewable Variable O&M Costs *(in 2010 real dollars/MWh)*	Onshore Wind: $0 Offshore Wind: $0 Utility PV: $0 Rooftop PV: $0	
18 Renewable Maximum Potential Capacity *(in MW)*	Onshore Wind: 6100 Offshore Wind: 70000 Utility PV: 67000 Rooftop PV: 22000	MWRS 2009[24] AWS Truepower

[24] MWRS 2009 = Michigan Wind Resource Study 2009.

Table A-1 (continued)
Key Michigan-specific assumptions used in this report

Assumption	Michigan Value(s)	Source
19 Renewable Capacity Factors	Onshore Wind: 31%-37% Offshore Wind: 52% Utility PV: 14% Rooftop PV: 11%	AWS Truepower
20 Energy Efficiency Costs *(in 2010 real dollars)*	550 per first year MWh, avoided MWh assumed to decline linearly to zero after twenty years. (Equivalent to 55/MWh.)	EPA CPP Proposal 2014
21 Coal Retrofit Costs[25] *(in 2010 real dollars/kW)*	Convert to Gas: 150 Convert to Biomass: 1000 Retrofit to CCS: 1478 Retrofit for 5% biomass co-firing: 20	EPRI TAG Program

[25] US-REGEN assumes all coal units in 2015 to be in compliance with MATS, or to be scheduled for retirement.

Appendix B: Abbreviations

Table B-1
Abbreviations and acronyms used in this report

Abbr.	Definition
AEO	Annual Energy Outlook
CAA	Clean Air Act
CGE	Computable Generation Equilibrium
CO_2	Carbon Dioxide
CPP	Clean Power Plan
EE	Energy Efficiency
EGU	Electric Generating Unit
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERC	Emission Rate Credit
GW	Gigawatts
ITC/PTC	Investment Tax Credit and Production Tax Credit
mmt	Million metric tons
NGCC	Natural Gas Combined Cycle
NGGT	Natural Gas Turbine
RE	Renewable Energy
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
TWh	Terawatt-Hours
US-REGEN	U.S. Regional Economy, Greenhouse Gas, and Energy

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