EXPANDING THE RENEWABLE PORTFOLIO STANDARD FOR MICHIGAN: A STUDY

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PREPARED BY (ALL UNIVERSITY OF MICHIGAN):

Jeremiah Johnson
Assistant Professor, School of Natural Resources and Environment

Josh Novacheck
Research Assistant, School of Natural Resources and Environment

Mark Barteau
DTE Energy Professor of Advanced Energy Research, College of Engineering

Thomas Lyon
Dow Professor of Sustainable Science, Technology, and Commerce, Ross School of Business

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EXPANDING THE RENEWABLE PORTFOLIO STANDARD FOR MICHIGAN: A STUDY

Executive Summary

Twenty-nine states have binding Renewable Portfolio Standards (RPS), which have served as key drivers for renewable energy development. In 2008, Michigan adopted the Clean, Renewable, and Efficient Energy Act (P.A. 295), which requires 10% of retail sales to be met by qualified renewable sources by 2015. Through existing sources, new utility-owned generation, and power purchase agreements, this target is expected to be met.

In 2012, Proposition 3 offered an amendment to Michigan's Constitution mandating 25% renewables by 2025 in Michigan, with some cost containment measures. This proposal did not pass, leaving no further requirement for future renewable development in Michigan beyond 2015. Despite this loss, renewable energy advocates contend that an expanded RPS is an effective and worthwhile strategy to reduce environmental impacts from the power sector.

The study provides a rigorous and neutral assessment of the impacts of expanding Michigan's RPS on the state's generation mix, emissions, and costs to rate payers. A comprehensive economic dispatch model was used to determine generator behavior and market energy prices, while a renewable revenue requirement model determined the lowest cost renewable technologies and sites needed to comply with the RPS targets. A wide array of scenarios, policy variations, and sensitivities are assessed to offer a robust picture of the impacts of expanding RPS under a variety of system assumptions and policy designs, detailed in Figure ES-1.

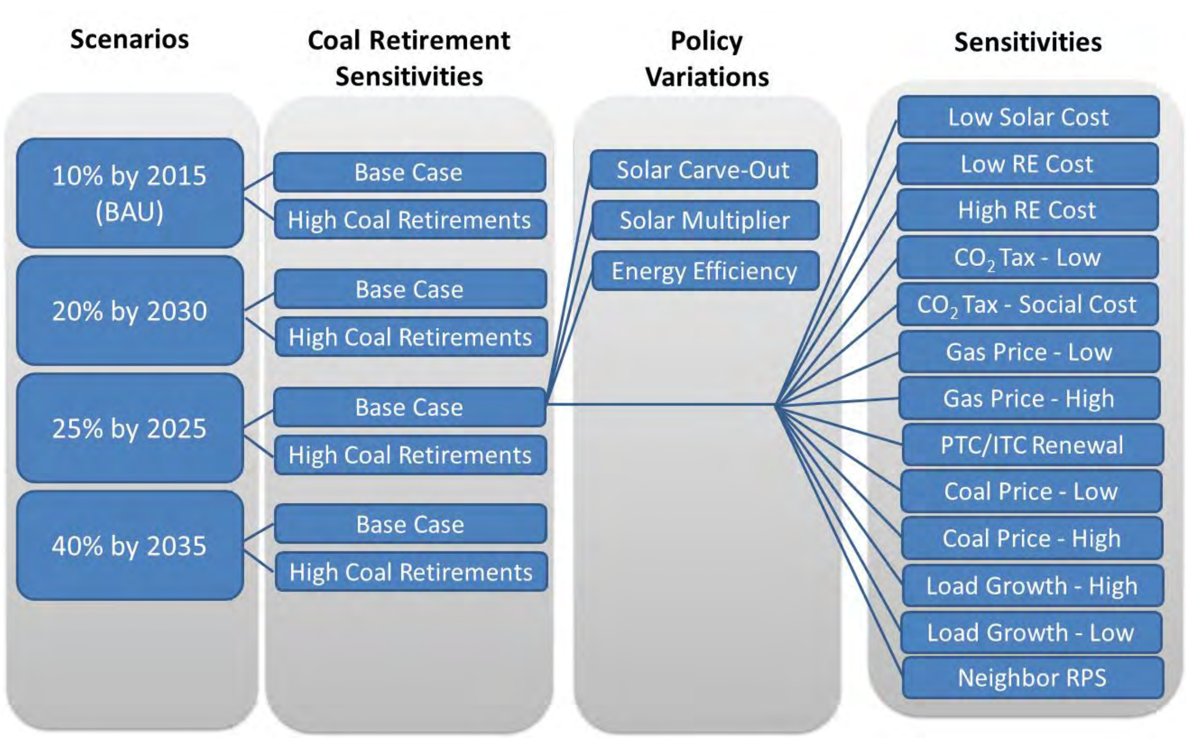


Figure ES-1: Summary of RPS Scenarios, Policy Variations, and Sensitivities
BAU = Business as Usual; RE = Renewable Energy; PTC = Production Tax Credit; ITC = Investment Tax Credit

Three RPS scenarios present different renewable generation targets and timelines: (1) 20% by 2030, (2) 25% by 2025, and (3) 40% by 2035. Each scenario is compared to a "business as usual" (BAU) case, which maintains but does not expand upon the current RPS. Base case assumptions employed in each scenario are conservative with regard to coal unit retirements, but each scenario is also evaluated under high coal retirement assumptions. In addition, the three policy variations, which are tested on the 25% by 2025 RPS case, include: (1) a solar energy carve-out equal to 20% of the incremental RPS, (2) solar energy multiplier at three credits per MWh, and (3) the allowance of energy efficiency to meet RPS. The sensitivity of the results to key assumptions are tested, including a range of installed cost for renewable generation, two levels of CO_2 tax, an extension of key federal subsidies for renewables, neighbor states adopting comparable RPS policies, and high and low assumptions for natural gas price, coal price, and load.

Figure ES-2 shows the resulting generation mix for each of the base case scenarios. Figure ES-2a shows the BAU future dominated by coal and nuclear, with modest contributions by natural gas and wind. Figures ES-2b and ES-2c show that the expansion of the RPS to 20% and 25%, respectively, increases onshore wind generation while displacing coal and some natural gas. With a target of 40% renewables (Figure ES-2d), utility-scale solar is becomes favorable relative to additional onshore wind development in the later years of the study.

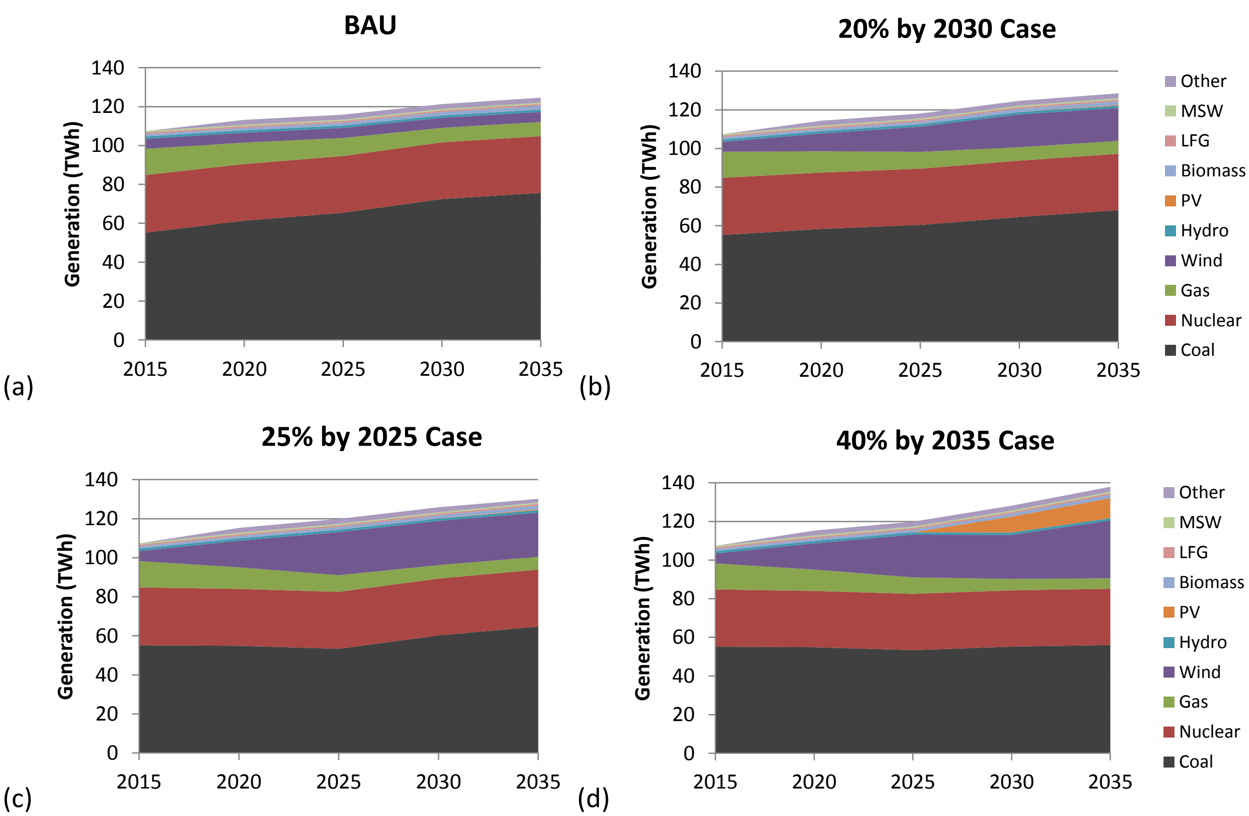
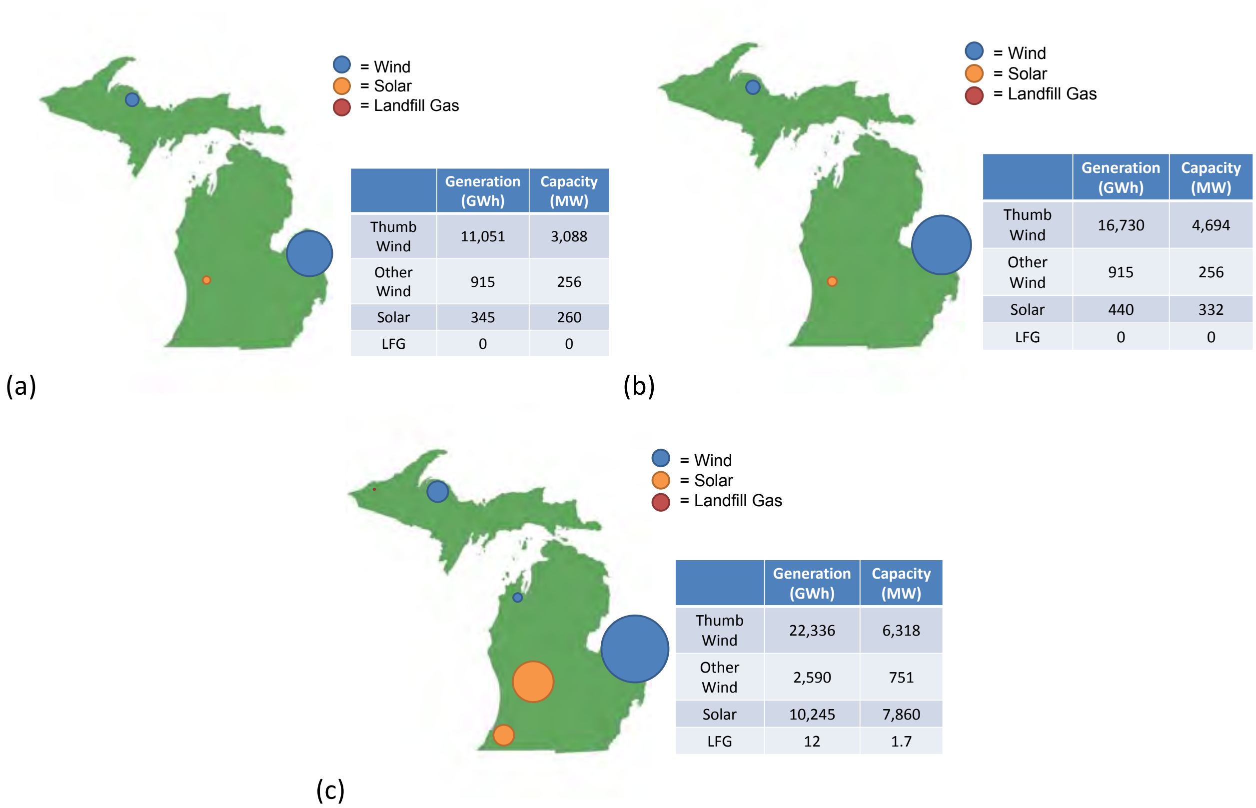


Figure ES-2: Michigan Generation Mix by RPS Scenario - (a) Business as Usual (BAU), (b) 20% by 2030 Case, (c) 25% by 2025 Case, (d) 40% by 2035 Case. Abbreviation key: LFG = landfill gas; MSW = municipal solid waste; PV = photovoltaic; RE = renewable energy.

Figure ES-3 shows the installed capacity of the incremental renewables needed to meet the expanded RPS targets, with approximate locations. Onshore wind in the "Thumb" region of Michigan provides the majority of lowest cost renewable energy in all three cases. In the 40% RPS case (Figure ES-3c), solar generation makes a significant contribution (29%) to the incremental renewable generation.



(a)

	Generation (GWh)	Capacity (MW)
Thumb Wind	11,051	3,088
Other Wind	915	256
Solar	345	260
LFG	0	0

(b)

	Generation (GWh)	Capacity (MW)
Thumb Wind	16,730	4,694
Other Wind	915	256
Solar	440	332
LFG	0	0

(c)

	Generation (GWh)	Capacity (MW)
Thumb Wind	22,336	6,318
Other Wind	2,590	751
Solar	10,245	7,860
LFG	12	1.7

Figure ES-3: Generation and capacity of incremental renewable energy in 2035, with approximate location of generation, for the (a) 20% by 2030 case, (b) 25% by 2025 case, and (c) 40% by 2035 case

In the base case scenarios, the only coal retirements included are those that have been announced and those for which the future costs of operating and installing control equipment to comply with the Mercury and Air Toxics Standard (MATS) exceeds the cost of a new natural gas combined cycle. This approach yielded 1.1 GW of announced retirements and 754 MW of MATS-driven retirements, which were primarily smaller coal units. These assumptions for the magnitude of coal retirements may prove to be overly conservative, particularly in light of the EPA's proposed rules to reduce carbon emissions from existing power plants. The sensitivity of the results to the assumptions on coal unit retirements was tested by assuming coal plant retirements occur based on vintage, with retirement occurring after 50 years of operation. In this sensitivity, units retired due to vintage are replaced by a comparable capacity of natural gas combined cycle units. This results in a near-complete phase-out of coal by the end of the study period (2035).

When compared to the base case retirement scenarios, the alternative coal retirement sensitivities yielded significantly different generation mixes, as shown in Figure ES-4. Much of the reduction in coal generation was replaced with natural gas generation, although some of the impact of the retirements was mitigated by a decrease in the net electricity exports out of Michigan. The generation mix of new renewables is comparable to other cases, with onshore wind dominating the new additions and some solar photovoltaics contributing in the 40% case.

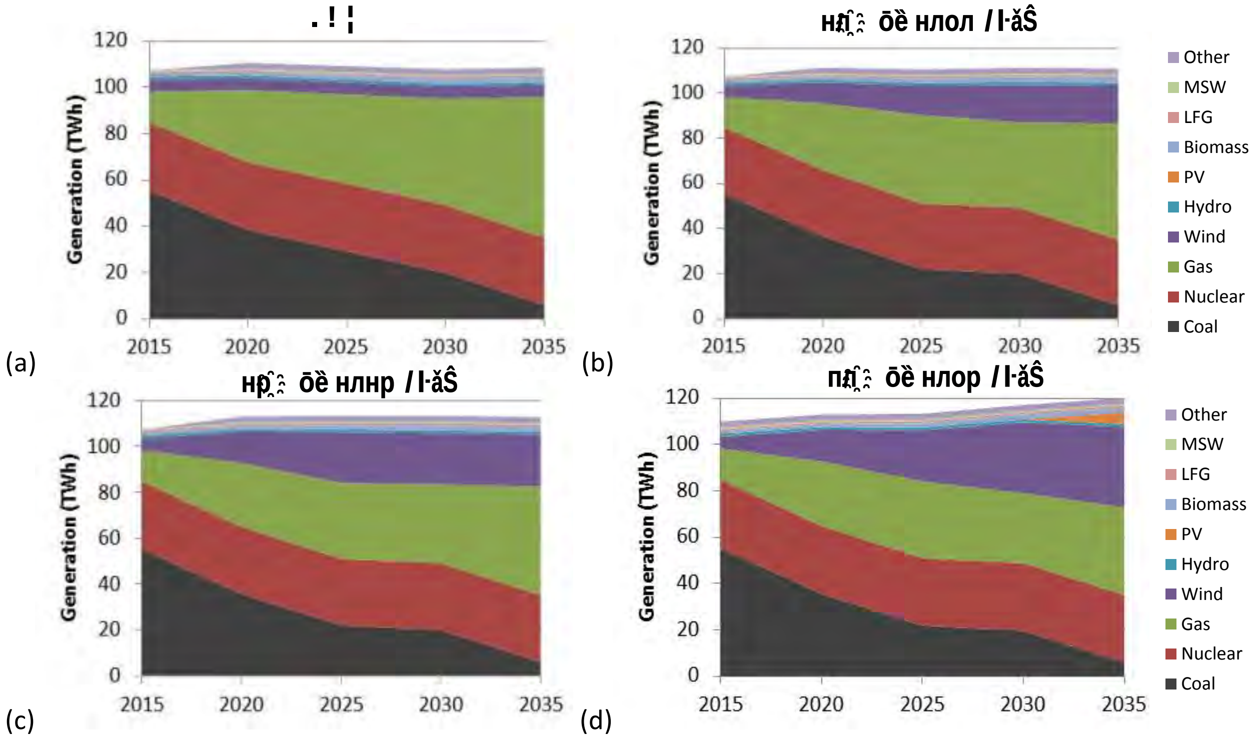


Figure ES-4: High Coal Retirement Sensitivities - Michigan Generation Mix by RPS Scenario - (a) Business as Usual (BAU), (b) 20% by 2030 Case, (c) 25% by 2025 Case, (d) 40% by 2035 Case. Abbreviation key: LFG = landfill gas; MSW = municipal solid waste; PV = photovoltaic; RE = renewable energy.

Figure ES-5a shows CO_2 emissions intensities for each of the four main scenarios under base case assumptions. Because the BAU case has 10% of demand met by renewables, the 20% by 2030 case adds renewables equal to 10% of retail sales; the 25% by 2025 case adds renewables equal to 15% of retail sales; and the 40% by 2035 adds renewables equal to 30% of retail sales. Under base case assumptions, the three expanded RPS cases reduce the carbon intensity of generation by 13%, 20%, and 33%, respectively.

As seen in Figure ES-5b, the BAU case demonstrates that the retirement of additional coal units and their replacement with efficient natural gas combined cycle units significantly reduces Michigan's carbon intensity of generation from 0.6 t CO_2/MWh to 0.3 t CO_2/MWh. The relative impacts of the RPS program on CO_2 emissions intensity are comparable to the base case coal retirement results, but these decreases are relative to the already reduced emissions stemming from higher levels of coal retirements.

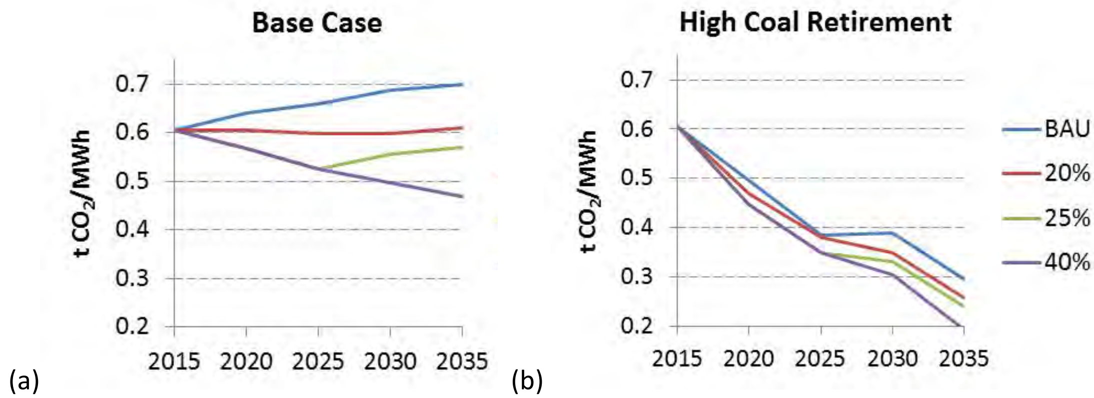


Figure ES-5: CO_2 Emissions Intensity for (a) Base Case, and (b) High Coal Retirements, for Four Scenarios - Business as Usual (BAU), 20% by 2030, 25% by 2025, 40% by 2035

When considering the cost impacts of the Michigan RPS program, it is essential to consider not only the power purchase agreement (PPA) costs of new renewables, but those costs offset by the introduction of renewables. The costs of the expanded RPS program were determined for each of the scenarios, as shown in Figure ES-6, with results segmented into the following categories:

1. "New Renewable PPA" represents the contract costs of new renewable projects.
2. "Net Imports" represents the change in revenues or costs to Michigan rate payers based on changes to the amount of electricity imported or exported. A negative value indicates a reduction in costs to Michigan rate payers, typically through increased exports.
3. "Capacity Expansion" is the reduction in costs to procure new firm capacity associated with the assumed capacity value of renewables.
4. "Variable Cost of Generation" represents the change in production costs associated with utility-owned generation and the change in market energy costs for other generation.

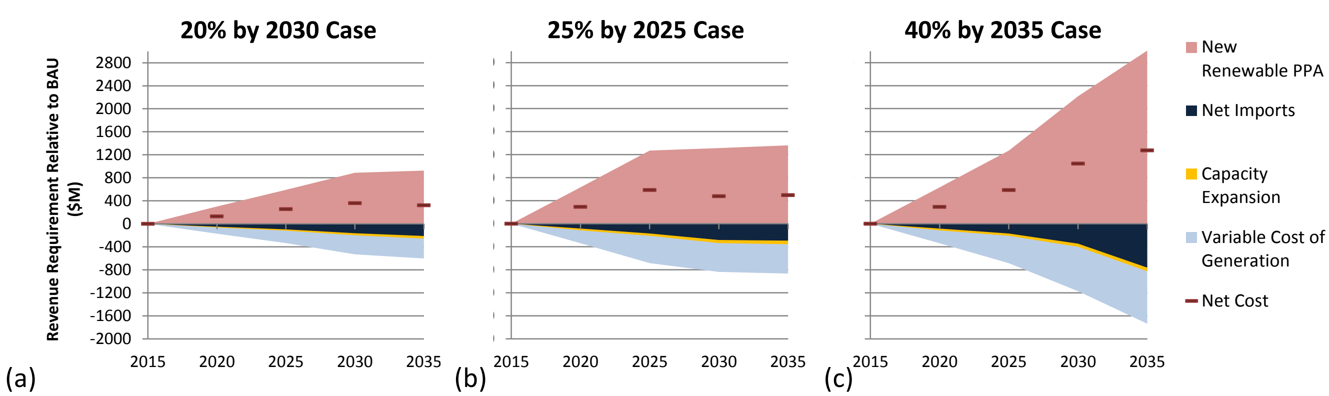


Figure ES-6: RPS Program Costs (a) 20% by 2030 Case, (b) 25% by 2025 Case, (c) 40% by 2035 Case; all values in 2013$

As shown in Figure ES-6, the most important drivers to RPS program net costs are the costs associated with new renewable PPAs and the reduction in the variable cost of other generation (e.g., reduced generation from coal and natural gas plants). PPA costs are offset by reductions totaling between 53% and 65% of the costs of the PPA.

For the 20% by 2030 case, the additional costs associated with the RPS program reach up to $360 million per year (in 2013$). The net present value (NPV) of the program costs over a twenty-year horizon, discounted at 7% per year, total $1.9 billion. At the end of the study period (2035), the impacts of this program on a "typical" household that consumes 600 kWh per month would be $1.70 per month, assuming program costs are evenly divided across all load. This would be less than 2% of the total bill, assuming other fixed costs remain constant.[1]

For the RPS target of 25% by 2025, the peak incremental program costs are $590 million per year in 2025 and decrease thereafter. The NPV of program costs are $3.6 billion and the impact to the "typical" household would be $2.60 per month in 2035, a 3% increase.

The annual RPS program costs for the more ambitious 40% by 2035 case reaches $1.27 billion in 2035, with an NPV of $5.2 billion. To achieve this penetration of renewables, in 2035, the "typical" household would see an increase of $6.70 per month, a 7% increase. The RPS program costs are largely comparable under the high coal retirement scenarios, with 2035 RPS program costs equating to increases for the "typical" household of $1.20 per month, $2.60 per month, and $4.70 per month, respectively, for the 20%, 25%, and 40% RPS cases.

The sensitivity analysis demonstrated that there are several situations examined that can greatly reduce RPS program costs, such as introducing an RPS in the presence of a carbon tax, the return or extension of federal subsidies ("PTC/ITC Returns"), and lower installed costs for renewables. Only one sensitivity (higher installed costs for renewables) significantly increases program costs.

Three policy design variations were also examined. The solar carve out, which mandates that at least 20% of new renewables are solar, results in a modest increase in program costs and negligible impact on emissions. The solar multiplier, which awards triple credit for solar generation, results in significantly less renewable generation, which in turn results in lower RPS program costs. Allowing energy efficiency to count towards RPS compliance was found to lower program costs, but does introduce challenges in measurement and accountability.

This study found that the expansion of Michigan's RPS would decrease air emissions under every scenario, policy variation, and sensitivity. This analysis demonstrates that significant emissions reductions would be achieved by expanding Michigan's Renewable Portfolio Standard at costs to consumers that are far smaller than many recent fuel price variations. These results, coupled with the successful implementation of the original RPS goal of 10% by 2015, demonstrate that Michigan has the potential to fundamentally improve the environmental performance of its power sector in a cost effective manner.

[1] This holds delivery charges, sales tax, and other charges constant, at rates equivalent to DTE Energy's current charges for residential customers.

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1.0. Background

Renewable Portfolio Standards (RPS) are state-level policies which typically mandate that a set share of electricity demand must be met by qualified renewable energy resources. These policies can vary greatly from state to state, with different renewable penetration requirements, eligible sources, delivery requirements, and penalties for non-compliance. In many states, RPS policies are directly attributable to increases in significant quantities of renewable generation.

Michigan is one of 29 states with a binding RPS policy in place. Under the Clean, Renewable, and Efficient Energy Act of 2008 (P.A. 295), Michigan's load serving entities are responsible for generating 10% of their retail electricity sales from renewable sources by 2015. Through new utility-owned generation, existing generation, and power purchase agreements, it is expected that this target will be met.[2] Michigan now has 1,163 MW of onshore wind, most of which was developed after the inception of P.A. 295. Negotiated contracts for wind have come in below expected costs, with some projects under $50/MWh.[3] Many utilities in Michigan no longer have a renewable energy surcharge due to lower than expected costs.[4]

In 2012, groups advocating for renewable energy failed to pass Proposition 3, which would have added an amendment to Michigan's Constitution mandating 25% renewable energy by 2025, while limiting cost increases to no more than 1% per year. The debate over this proposal was heated and oftentimes lacked objective analytical rigor when discussing the costs and benefits of expanding Michigan's RPS. To better inform future policy debates, this study, supported by the University of Michigan Energy Institute, assesses the costs and environmental impacts of alternative RPS designs for Michigan.

1.1. Overview of the Current Michigan RPS

P.A. 295 requires all electricity providers to meet 10% of their Michigan retail load with renewable energy by 2015. This includes all investor owned utilities, municipal utilities, electric cooperatives, and alternative electric suppliers. It is expected that nearly all providers will achieve the target, with the vast majority of new renewable generation coming from wind power. When including renewables that existed before P.A. 295 and any RPS incentives, wind energy will meet about 50% of the required renewable energy generation in 2015.[5]

Under P.A. 295, every megawatt-hour of renewable electricity produces a Renewable Energy Credit (REC). Each electricity provider is then required to procure RECs equal in quantity to 10% of their load, with REC trading allowed among providers. P.A. 295 also includes various incentives to encourage certain types of renewable and advanced energy technologies. Many of these incentives take the form of REC multipliers, including[6]:

- 1.1 multiplier for renewable energy projects using materials manufactured in Michigan

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[2] Michigan Public Service Commission, "Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards," 2014.
[3] Ibid.
[4] Ibid.
[5] Ibid.
[6] Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MI16R, accessed on September 30, 2014.

- 1.1 multiplier for renewable energy projects using Michigan labor
- 3 multiplier for all solar generation
- 1.2 multiplier for all non-wind on-peak generation, where peak = weekdays from 6 a.m. to 10 p.m.
- 1.2 multiplier for any off-peak generation stored using energy storage technology for use on-peak.

In recent years, approximately 10% of all RECs produced or acquired by electricity providers were from incentive multipliers and this trend is expected to continue into 2015.[7] These incentives reduce the total renewable generation; with 10% of RECs coming from incentive multipliers, renewable energy generation will meet 9% of Michigan's total electricity demand.

Energy Optimization (EO) and Advanced Cleaner Energy Credits (ACEC) can also be used to meet Michigan RPS targets. EO is the term used for energy efficiency and includes measures taken to reduce consumer energy use. ACECs are obtained from generation of electricity by a qualifying nonrenewable, but advanced generation technology. These technologies typically must be highly efficient or have low CO_2 emissions relative to conventional generator technologies. Examples of qualifying technologies are industrial cogeneration, and carbon capture and sequestration technology installed on a coal plant. EO and ACEC can make up 10% of all RECs required under P.A. 295, although it is not expected that electricity providers will substitute enough EO and ACEC to meet the 10% of all REC limits.[8]

After Michigan's RPS targets are met in 2015, there is no statewide legal mandate for load-serving entities to further increase the share of renewable generation. This study examines multiple alternatives to expanding the state's RPS, with a focus on the impacts to emissions, generation mix, and program cost.

1.2. Integrating Renewables

There are a variety of forms of renewable generation that qualify for RECs in Michigan. Based on project costs and resource quality, the majority of RECs generated to comply with P.A. 295 will come from wind power. However, as the installed cost of solar continues to decrease, solar generation could become more cost effective than wind and contribute significantly to future RPS requirements in Michigan. Both of these resources are variable, only generating when the wind is blowing or the sun is shining. Therefore, they must be balanced by dispatchable generation such as coal and natural gas-fired facilities, creating new challenges to grid operation.

At the moment, there is very little large-scale, fast-reacting energy storage connected to the grid, so power supplied from generators always must equal the power demanded in real time. This can be particularly challenging if, for example, wind speeds suddenly die down. In general, variable renewable generation causes more conventional generators to undergo more frequent starts and stops, operate less efficiently at partial loads, and require the provision of additional ancillary services (i.e., grid support to maintain reliable operations) to react quickly to changes in power output. Renewable generation displaces conventional generation, reducing fossil fuel consumption and a variety of harmful air emissions emitted due to the combustion of those fuels. This study captures the operational dynamics of the power system that are necessary to fully understand the impacts of an expanded RPS in Michigan.

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[7] Michigan Public Service Commission, "Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards," 2014.
[8] Ibid.

2.0. Study Objectives and Design

The objective of this study is to assess the impact of expanding Michigan's RPS on emissions, generation mix, and program cost. A variety of renewable targets and RPS design options are tested over a 20-year study horizon to inform stakeholders of the environmental and economic implications of RPS policy designs. Robust power systems models are used to determine the lowest cost means of compliance. Given the importance and uncertainty of key assumptions, multiple sensitivity analyses are conducted.

2.1 Alternative RPS Scenarios, Policy Variations, and Sensitivities

To assess the environmental and cost impacts of an increased RPS, this study examined multiple renewable penetration targets, RPS design considerations, and the sensitivity to key assumptions.

Three scenarios were chosen with different renewable generation targets: (1) 20% by 2030, (2) 25% by 2025, and (3) 40% by 2035. Each scenario is compared to a "business as usual" (BAU) scenario, which maintains but does not expand upon the current RPS. (Because no new renewables are built after 2015 in the BAU case, load growth over the study period slightly reduces the share of load met by renewables.) Figure 2-1 shows the renewable energy target for each of the scenarios.

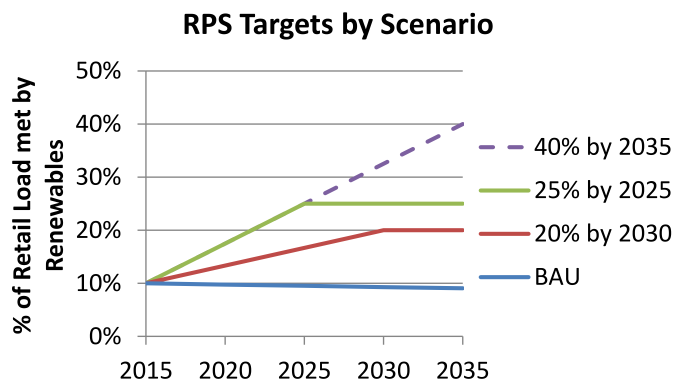

Figure 2-1: Renewable Targets by RPS Scenario
BAU = Business as Usual

In all scenarios, the mandate from the existing RPS for 10% renewables is met in 2015, using all currently allowable means to meet the target (e.g., credit multipliers and incentives). This study analyzes the impacts of any increase above the 10% target, with all additional RECs coming solely from renewable energy generation (i.e., no incentive multipliers nor non-renewable substitutions). The types of renewable energy considered are wind energy from utility-scale wind farms, utility-scale solar photovoltaics, distributed scale solar photovoltaics (commercial and residential solar), biomass generation (including crop residue, switchgrass, forest residue, primary mill, secondary mill, and urban wood), landfill gas, and municipal solid waste.

While not necessarily driven by RPS policy, the magnitude and timing of coal unit retirements can greatly influence the generation mix, which in turn influences the environmental and economic impacts of an expanded RPS program. Base case assumptions employed in each scenario are conservative with regard to coal unit retirements, but each scenario is also evaluated under high coal retirement assumptions. Figure 2-2 provides a summary of all scenarios, policy design variations, and sensitivities.

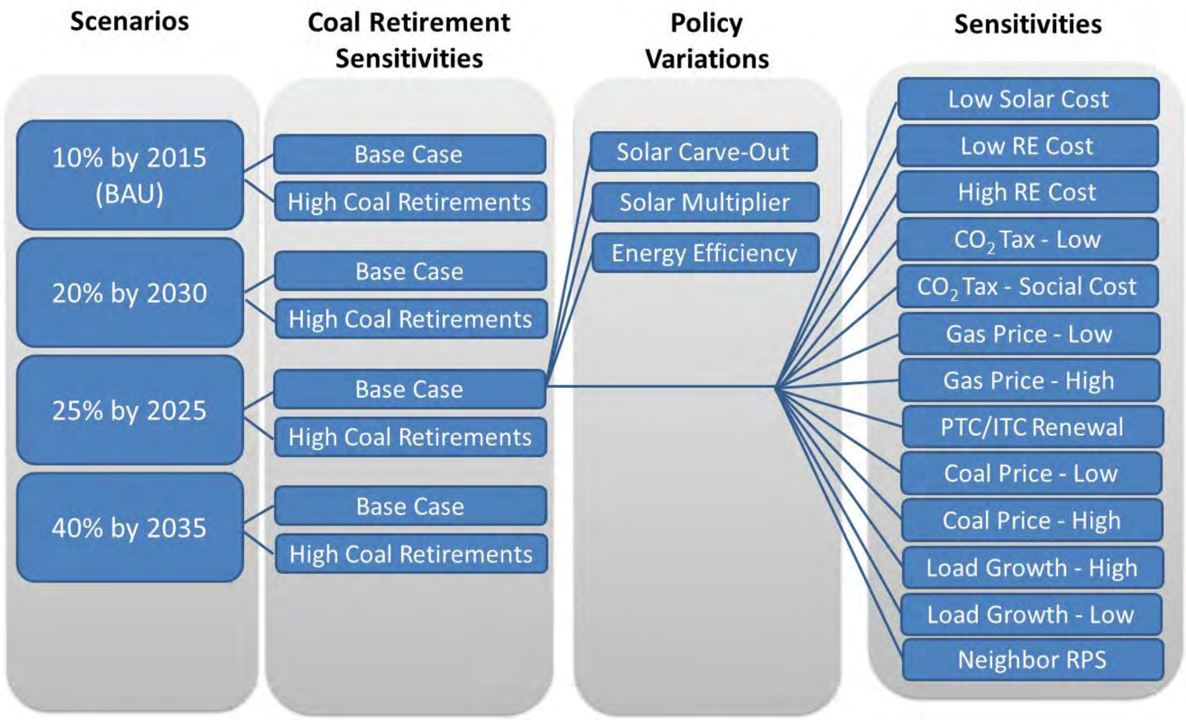

Figure 2-2: Summary of RPS Scenarios, Policy Variations, and Sensitivities
BAU = Business as Usual; RE = Renewable Energy; PTC = Production Tax Credit; ITC = Investment Tax Credit

The base case assumptions for all scenarios did not include incentive mechanisms nor allow energy efficiency as an eligible resource. The three policy variations, which are tested on the 25% by 2025 RPS case, include: (1) a solar energy carve-out, (2) solar energy multipliers, and (3) energy efficiency credits. The solar energy carve-out assumes that at least 20% of the incremental RPS requirement must come from solar energy generation. This policy variation is similar to measures put into effect in several states, including Ohio and New Jersey.[9] The solar multiplier assumes a continuation of Michigan's incentive, which awards three RECs for each megawatt-hour of solar generated. The energy efficiency policy variation allows demand-side measures to receive RECs to be used to meet RPS goals.

Modeling the impact of RPS scenarios twenty years into the future relies on numerous important, but uncertain assumptions that can have major impacts on the environmental impacts of an expanded RPS, as well as program costs. Therefore, multiple sensitivities are modeled to understand the impact of key assumptions on the results. The sensitivities are listed in Figure 2-2 and include a range of installed cost for renewable generation, two levels of CO_2 tax, an extension of key federal subsidies for renewables (i.e., the Production Tax Credit (PTC) and the Investment Tax Credit (ITC)), neighbor states adopting comparable RPS policies, and high and low assumptions for natural gas price, coal price, and load.

In the next section, more detail is provided including the key assumptions and the methods used to optimize the system in light of various RPS configurations.

[9] Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org, accessed on September 30, 2014.

3.0. Methods

An iterative process involving two models was employed to determine the minimum cost configuration to comply with RPS standards, as shown in Figure 3-1. A comprehensive economic dispatch model was used to determine generator behavior and market energy prices, while a renewable revenue requirement model determined the lowest cost renewable technologies and sites needed to comply with the RPS targets. The new projects are then added to the system representation used by the economic dispatch model, given that building new renewable capacity influences power system operation and the selection of future renewable projects. The models are run at five-year increments through the study period of 2015 to 2035. Based on resulting generator behavior, the dispatch model provides results on emissions for CO_2, SO_2, and NO_x, as well as fuel consumption. Both models are used collectively to determine total RPS program costs.

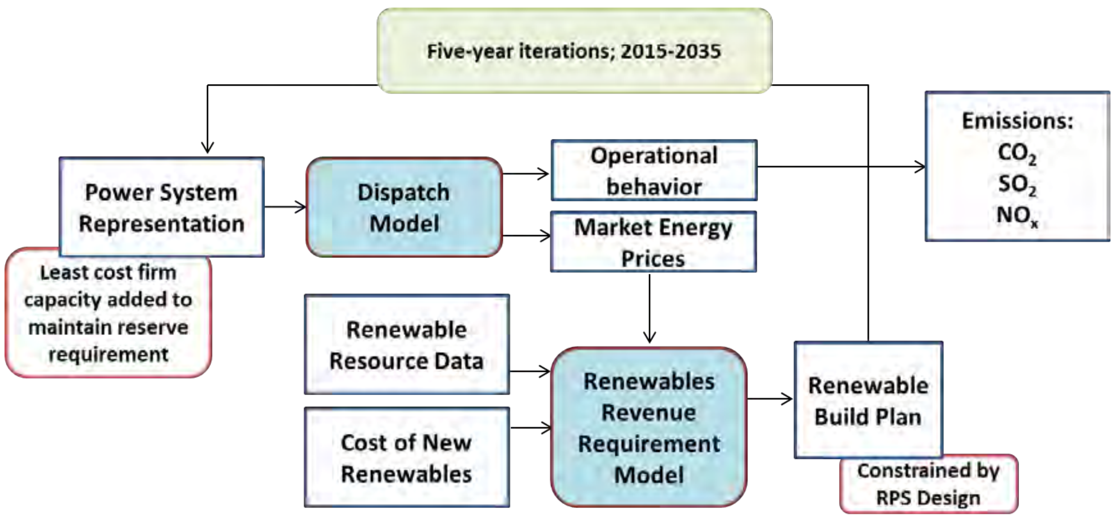

Figure 3-1: Overview of Methodology to Evaluate Michigan's Renewable Portfolio Standard

3.1. Economic Dispatch Model

The economic dispatch model used in this study is the commercially-available Plexos for Power Systems by Energy Exemplar. This software uses linear programming to determine the optimal unit commitment and dispatch to meet demand at the lowest cost possible. The assumptions for generators, transmission, demand, ancillary services, fuel, and emissions are inputs into this model, as described in the following sections. The system is solved chronologically in hourly increments with a high degree of data resolution to fully capture the system characteristics.

Given the interconnected nature of the power grid, it is essential that the spatial boundary of the study is sufficiently large in order to capture the import and export characteristics to and from Michigan. This is achieved in two steps. First, the full Eastern Interconnection is modeled, representing the entire U.S. portion of this synchronous grid. Then, a constrained geography is created that includes Michigan, plus the northern portion of the Midcontinent Independent System Operator (MISO) and neighboring zones in PJM. Figure 3-2 shows the spatial boundaries of the full and constrained representations, with the constrained geography represented in color. Imports into and exports out of the neighboring zones from the rest of the Eastern Interconnection are held constant based on the output of the full Eastern

Interconnection modeling results. Within each zone, generators, fuel price, and load are modeled using the assumptions detailed in the following sections.

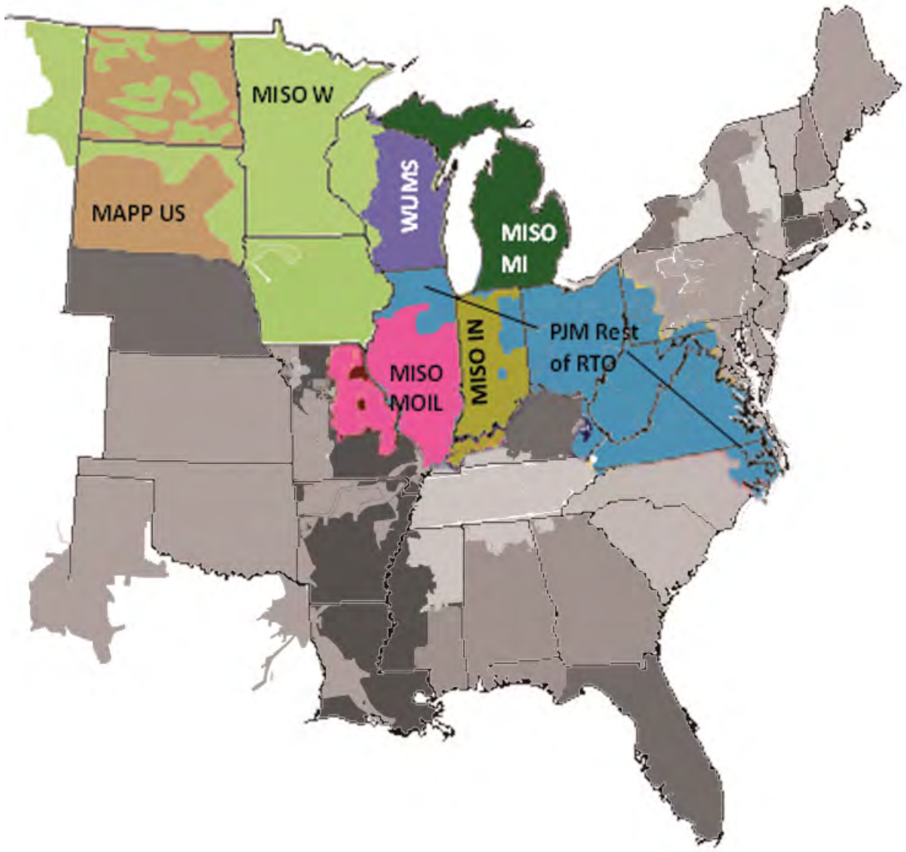

Figure 3-2: Zonal Boundaries for the Full System Representation, in grayscale, and the Constrained System Representation, in color

3.1.1. Generators

Approximately 10,000 generators are represented across the Eastern Interconnection, including all generators at least 100 kW in size. Smaller generators (less than 10 MW) are included in an aggregated manner. Key assumptions for each generator include the full load heat rate, partial load heat rate impacts, variable operations and maintenance costs, operating capacity range, primary fuel type, forced outage rate, and emissions control technologies for NO_x and SO_2. Table 3-1 provides a summary of data sources for generator assumptions and relevant notes on these assumptions. Table 3-2 provides assumptions on forced outage rate by technology and fuel type[10], while Table 3-3 provides assumptions on SO_2 removal efficiency by emissions control technologies. Figure 3-3 shows the heat rate curves for partial load operations, as a function of full load heat rate.

[10] Based on data from North American Electric Reliability Corporation, Generator Availability Data System, 2013.

Table 3-1 – Generator Operational Characteristics

	Notes	Source
Rated capacity		EIA 860 Database
Minimum operating capacity	Constant percentage of rated capacity for each generating unit type	Multiple sources[11] [12] [13]
Full load heat rate	Additional detail incorporated for Michigan generators	U.S. EPA eGrid and Air Market Program data
Variable operating and maintenance costs	Varies regionally throughout Eastern Interconnection. Constant by generator type for each zone	U.S. EIA[14]
Primary fuel type	Each generator assumed to only use their primary fuel	EIA 860 Database
Emissions control technologies		U.S. EPA Air Market Program data

Table 3-2 – Generator Availability Assumptions

Unit Type	Forced Outage Rates (%)	Mean Time to Repair (Hours)
Coal Steam Turbine	5.0	55
Nuclear	2.2	164
Combined Cycle	2.6	36
Natural Gas Combustion Turbine	3.5	115
Other Combustion Turbine	3.9	46
Biomass	6.5	73

Table 3-3 – SO_2 Removal Efficiency of Control Technologies

Technologies	Removal Rate
Dry Lime Flue Gas Desulfurization	93%
Dry Sorbent Injection	70%
Wet Lime FGD	95%

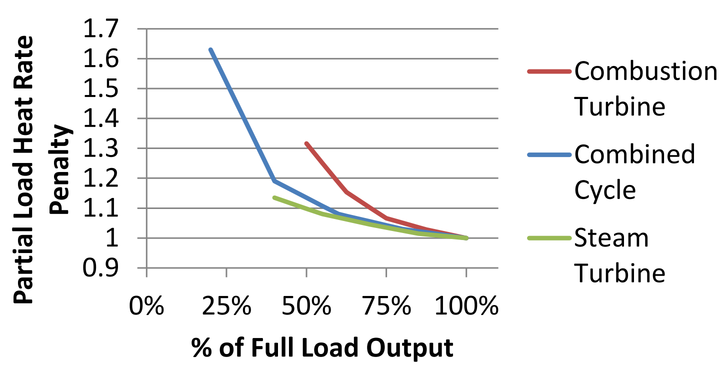

Figure 3-3: Partial Load Heat Rate Penalty

[11] GE Power Systems, Advanced Technology Combined Cycles.
[12] International Energy Agency, Power Generation from Coal, 2010.
[13] NERA Economic Consulting, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, July 2010.
[14] Updated Capital Cost Estimates for Electricity Generation Plants, US Energy Information Agency, November 2010.

3.1.2. Fuel

Fuel price forecasts are based on the EIA's 2014 Annual Energy Outlook (AEO) for coal and natural gas. Zonal fuel price differences are based on a weighted average of the fuel cost for generators within the same zone, using the EIA 923 database for generator fuel receipts. Coal prices remain constant throughout the year, while natural gas prices vary monthly. Figure 3-4 shows the annual average fuel prices for coal and natural gas in Michigan through the study period. The high and low prices are used only in the sensitivity analysis. For coal, the price sensitivities are based on AEO assumptions for high and low coal price forecasts, while the high and low prices for natural gas are assumed to be ±50% of the base price.

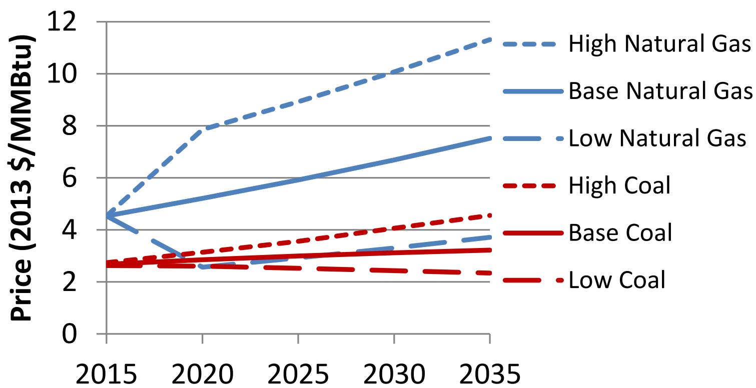

Figure 3-4: Coal and Natural Gas Price Forecast in Michigan (2013$)

Figure 3-4 shows the uncontrolled emissions rates assumed for each fuel type[15] [16]. NO_x emissions rates, which vary considerably among generators that use the same fuel, are generator-specific, relying on historical data from EPA eGrid Database.

Table 3-4: Uncontrolled Emissions Rates by Fuel Type

	Emissions Rate (lb/MMBtu)	
Fuel	CO_2	SO_2
Subbituminous Coal	213	1.00
Bituminous Coal	206	3.55
Natural Gas	117	0
Municipal Solid Waste	91	0.35
Fuel Oil	161	0

3.1.3. Load

Contemporary load data for the Eastern Interconnection is from Independent System Operators (ISOs) where available. For regions without such data, assumptions from the Eastern Interconnection Planning Collaborative study are used. When needed, load is adjusted to conform to zonal boundaries. For Michigan, the load growth forecast is 0.485%[17] per year and the annual peak demand growth

[15] Energy Information Administration, Carbon Dioxide Emissions Coefficients, http://www.eia.gov/environment/emissions/co2_vol_mass.cfm.
[16] EPA Base Case v410 Documentation Combined Report Chapter 11, August 2010.
[17] Michigan Public Service Commission/Michigan Energy Office, Readying Michigan to Make Good Energy Decisions: Energy Efficiency, November 2013.

forecast is 0.436%.[18] Because intra-zonal transmission is not modeled, the associated transmission losses are added to load, based on historical transmission loss rates from 2010 EIA State Profiles.

3.1.4. Transmission

Inter-zonal transmission interface limits are derived from Eastern Interconnection Planning Collaborative study and ISO studies. Hurdle rates are assumed to represent the cost of transmission between zones. Transmission into Canada is modeled as fixed generation based on historical trade flows, with data from the ISOs.

For all of the RPS scenarios, the preliminary assumption is that in-state transmission will be sufficient to support the planned growth in new generation. The Thumb Loop Project, which is currently in development, will be capable of providing a maximum capacity of 5 GW to the wind-rich "Thumb" area of Michigan[19]. This study assumes that the costs of the Thumb Loop Project are sunk costs and not attributable to future RPS expansions. For scenarios that result in more than 5 GW of resources developed in the Thumb (i.e., the 40% by 2035 case), the costs of further expanded transmission are discussed.

3.1.5. System Reliability

While economic dispatch models are not a substitute for full system reliability analyses, two approaches were taken to ensure that the resulting system configurations represent realistic and reliable systems: firm capacity requirements and spinning reserves. For each zone, the peak demand plus a reserve margin of 14.2%[20] determines the necessary firm capacity. Available capacity is calculated as the summer capacity of firm generation adjusted for the forced outage rate, plus any capacity credit awarded to variable renewables. This study assumes that wind is awarded 14.1% capacity credit, [21] while solar receives 38% capacity credit based on PJM protocols[22]. Additional natural gas combustion turbines are added to maintain capacity levels no lower than the peak demand plus the reserve margin. Both up and down spinning reserves are added to contingency reserves at a rate of 3% of wind capacity to cover short-term wind variability[23].

3.1.6. Pumped Storage Hydro

The Ludington pumped storage hydro facility plays an important role in the system operations in Michigan. To characterize the charging and discharging pattern at Ludington, this study relied on data for the average monthly generation data, the rated storage capacity, and the average yearly pumping load and generation to calculate the roundtrip cycle efficiency[24]. Based on these data, an operating schedule was created in which the facility generates during on-peak hours on weekdays and weekends, recharges during off-peak hours and on weekends, and starts on Monday at full capacity. Peak hours are defined as 7 a.m. – 9 p.m.

3.1.7. Generator Retirements

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[18] Midcontinent Independent System Operator, Planning Year 2014 LOLE Study Report, MISO Loss of Load Expectation Working Group, November 2013.
[19] ITC, Capital Project Profile: Thumb Loop 345 kV Transmission Line.
[20] North American Electric Reliability Corporation, 2013 Long-Term Reliability Assessment, December 2013.
[21] Midcontinent Independent System Operator, Planning Year 2014-2015 Wind Capacity Credit, December 2013.
[22] PJM Manual 21, Rules and Procedures for Determination of Generating Capability, March 2014.
[23] Based on three times the standard deviation of short term variability, as employed by National Renewable Energy Laboratory, "Eastern Wind Transmission and Integration Study," 2011.
[24] Consumers Energy Company/DTE Electric Company, Pre-Application Document For the Ludington Pumped Storage Hydroelectric Project, January 2014.

This study takes a conservative approach to assumed generator retirements. For the base case, unit retirements are driven by two factors: (1) the retirement has been announced by the owner of the generator, or (2) the cost of compliance and future operations under the Mercury and Air Toxics Standards (MATS) is greater the cost of building and operating a new natural gas combined cycle unit. The analysis for MATS-driven retirements resulted in 754 MW of coal plant retirements, primarily smaller units. Given the potential for a greater magnitude of coal retirements driven by environmental objectives, sensitivity is conducted under which coal units are retired after 50 years of operations. The capacity of these units is replaced by new natural gas combined cycle units equaling the capacity of the retired units.

3.1.8. Model Validation

To ensure that the model is a realistic representation of Michigan's power system, a model representing the power system in 2013 was run and the results for generation by fuel type and locational marginal price were compared to historical values. Figure 3-4 shows generation by fuel type for generators located within Michigan, showing close alignment of results for generator mix. The differences between the modeled results and historical values are modest and outweighed by year-over-year fluctuations.

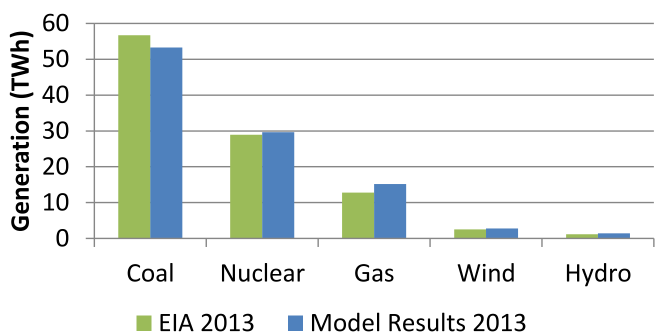


Figure 3-4: Actual and Simulated Generation in Michigan, 2013

Figure 3-5 shows the modeled locational marginal price (LMP) for each quarter in 2013. The LMPs are normalized to the annual average and compared to the historical LMPs for DTE Energy to assess the model's performance at capturing realistic seasonal and diurnal fluctuations in power price. Accurately capturing power price seasonality and differences in off-peak and on-peak prices is essential for appropriately valuing as-available resources such as solar and wind.

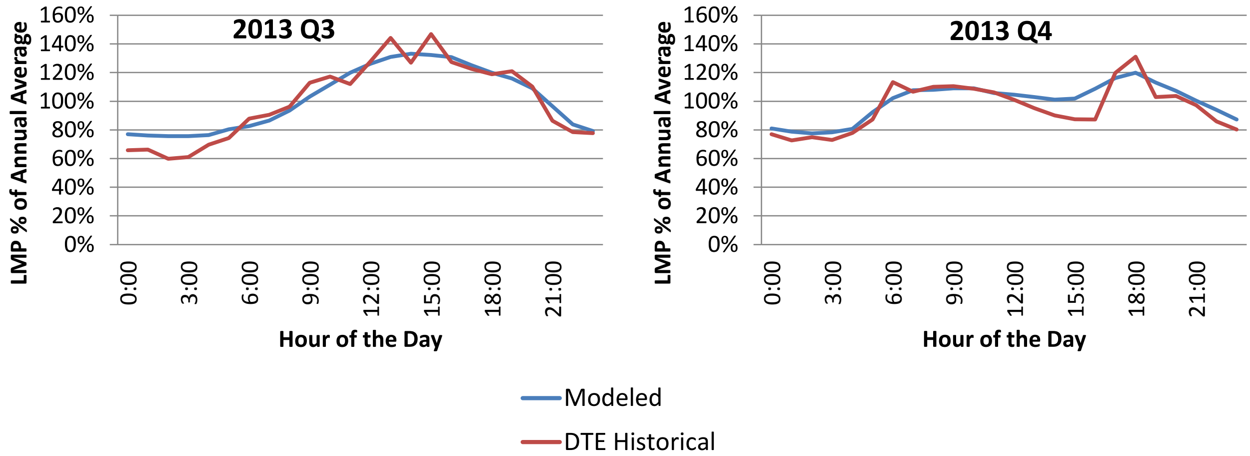


Figure 3-5: Actual and Simulated Locational Marginal Prices in Michigan, 2013

3.2. Renewable Site Selection Optimization

The renewable site selection optimization choses renewable energy projects that meet the RPS scenario requirements at the lowest cost possible for rate payers. The lowest cost projects are defined as those that minimize the above market costs of all potential projects. The above market costs are analogous to the cost of renewable energy credits (RECs) and are calculated as the difference between the needed power purchase agreement (PPA) costs for a project and the sum of the energy market revenues and capacity value. The approach to quantifying each of these terms is discussed in greater detail below.

3.2.1. Renewable Resource Potential

Wind resource potential and the power output profile in the study is obtained from the National Renewable Energy Lab's Eastern Wind Dataset. The dataset defines over 1,000 potential onshore wind farm sites within the US Eastern Interconnection, including 57 sites in Michigan.

Solar resource data is segmented into utility-scale and distributed generation (DG). Using NREL's System Advisory Model, data on solar generation was collected for six sites across Michigan. Biomass availability is based on the study "A Geographic Perspective on Current Biomass Resource Availability in the United States."[25] Resource data for landfill gas was based on the EPA's Landfill Methane Outreach Program's candidate landfills, converted to energy potential using the EPA conversion system[26].

For the energy efficiency sensitivity, the available efficiency potential is assumed to equal the constrained potential available under the Utility Cost Test (UCT).[27] This equates to approximately 5% of Michigan load.

3.2.2. Renewable Power Purchase Agreement

[25] Milbrandt, A Geographic Perspective on the Current Biomass Resource Availability in the United States, NREL/TP-560-39181. Golden, CO, National Renewable Energy Laboratory. 2005.
[26] US Environmental Protection Agency, Landfill Methane Outreach Program, http://www.epa.gov/lmop/projects-candidates/interactive.html, accessed June 4, 2014.
[27] Michigan Public Service Commission, "Michigan Electric and Natural Gas Energy Efficiency Potential Study," November 2013.

The power purchase agreement (PPA) for each renewable resource is based on the levelized cost for each resource, with key inputs including installed cost, operations and maintenance costs, debt-equity split, return on equity, debt rate, tax rates (income, property), insurance, and the availability of subsidies. Table 3-5 provides details on key assumptions used.

Table 3-5: 2013 Key Renewable Assumptions

Technology	Wind	Utility Solar	DG Solar	Biomass	Landfill Gas
Installed cost ($/kW)	1,940[28]	2,453[29]	4,734[30]	4,505[31]	1,816[32]
Annual change in installed cost (real $)	0%	15%[33]	9%[34]	0%	0%
Fixed O&M ($/kW-yr)	25[35]	23[36]	20[37]	106[38]	174[39]
Variable O&M ($/MWh)	-	-	-	5[40]	5[41]
Fuel cost ($/MMBtu)	-	-	-	1.90 – 4.12	2.20

The installed costs for solar power have been dropping rapidly in recent years. In the base case, these costs are assumed to drop at rates comparable to recent historical decreases until the installed costs reach the target of $1/W. The installed costs for other renewable resources are held constant in real terms.

Several sensitivities are conducted regarding the installed costs of renewables. In the "Low Solar Costs" sensitivity, solar installed cost declines at the same rate as the base case, but continues to decrease until reaching a floor of $0.50/W. In the "Low RE Cost" sensitivity, solar again reaches a floor of $0.50/W, while wind installed costs are 25% lower than base case assumptions. In the "High RE Cost" sensitivity, wind's installed cost is $2,425/kW, while solar's price floor is $1,250/kW.

In the base case, the federal renewable subsidies are not extended, meaning that the production tax credit (PTC) and investment tax credit (ITC) are not available. The impact of this assumption is tested in a sensitivity where both of these credits are available to all renewable resources and the optimal credit (ITC or PTC) is selected for each.

3.2.3. Renewable Resource Revenues

The energy market revenues for a potential renewable project are based on time of day of generation for that resource and the energy market price at that time, as provided by the economic dispatch model. By

[28] 2012 Wind Technologies Market Report, US Department of Energy, August 2013.
[29] Solar Energy Industries Association 2014 Quarter 1 reported installed cost (converted to kW-AC).
[30] Ibid.
[31] Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants, US Energy Information Agency, April 2013.
[32] Landfill Gas Energy: A Guide to Developing and Implementing Greenhouse Gas Reduction Programs, US Environmental Protection Agency, 2012
[33] Based on data from Solar Energy Industries Association quarterly reports (cost trend since 2012).
[34] Ibid.
[35] Updated Capital Cost Estimates for Electricity Generation Plants, US Energy Information Agency, November 2010.
[36] Ibid.
[37] Ibid.
[38] Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants, US Energy Information Agency, April 2013.
[39] Landfill Gas Energy: A Guide to Developing and Implementing Greenhouse Gas Reduction Programs, US Environmental Protection Agency, 2012
[40] Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants, US Energy Information Agency, April 2013.
[41] Updated Capital Cost Estimates for Electricity Generation Plants, US Energy Information Agency, November 2010.

reflecting the time of day of generation, resources such as wind that have more off-peak generation receive lower energy market revenues when compared to on-peak resources such as solar.

The capacity value for renewable resources is based on the awarded capacity credit for each type of resource and the cost of new entry for capacity. The assumed capacity credits are 14.1% of the installed capacity for wind, 38% for solar, and 80% for biomass, landfill gas, and municipal solid waste. The assumed value of capacity is $90/kW-yr[42], which represents the cost of new entry for a combustion turbine.

3.2.4. Model Validation

To ensure the validity of the renewable site selection optimization results, the value of the least cost PPA (with the availability of the PTC and ITC) was compared against recent PPAs signed in Michigan. The results of the model show wind projects available at $56/MWh, while PPAs for wind power signed by DTE Energy in 2012 and 2013 ranged from $49/MWh to $53/MWh[43]. This comparison demonstrates that the renewable revenue requirement model presents a realistic view of the resource costs in Michigan.

3.3. Program Cost Methods

Four cost categories are considered when assessing the costs attributable to the expanded RPS program:

1. New Renewable PPAs: These are the costs associated with meeting the revenue requirements associated with the new renewable projects mandated by the expanded RPS, indicative of a power purchase agreement (PPA). This cost category does not include the costs associated with the renewables which are needed to meet the existing 10% RPS goal.
2. Net Imports: This represents the change in revenues or costs to Michigan rate payers based on changes to the amount of electricity imported or exported. A negative value demonstrates a reduction in costs to Michigan rate payers, typically through increased exports.
3. Capacity Expansion: This is the reduction in costs to procure new firm capacity associated with the assumed capacity value of renewables.
4. Variable Cost of Generation: This represents the change in production costs associated with utility-owned generation and the change in market energy costs for other generation.

These four categories represent the subset of the total costs that rate payers incur which are directly impacted by the expanded RPS policies. To estimate the relative impacts to total rates of the RPS programs, other non-impacted costs are assumed to hold constant across all scenarios.

[42] Midcontinent Independent System Operator, https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/LRZ%20CONE%20Filing_3%20Sept%202013.pdf, September 2013.

[43] Michigan Public Service Commission, "Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards," 2014.

4.0. Results

Expanding the RPS for Michigan impacts future emissions, generation mix, and cost. For each scenario, policy variation, and sensitivity, the results of the associated impacts are presented below.

4.1. Generation Mix

The resulting mix of generation directly impacts the total emissions and costs to rate payers. Figure 4-1 shows the generation by type for each of the four main scenarios.

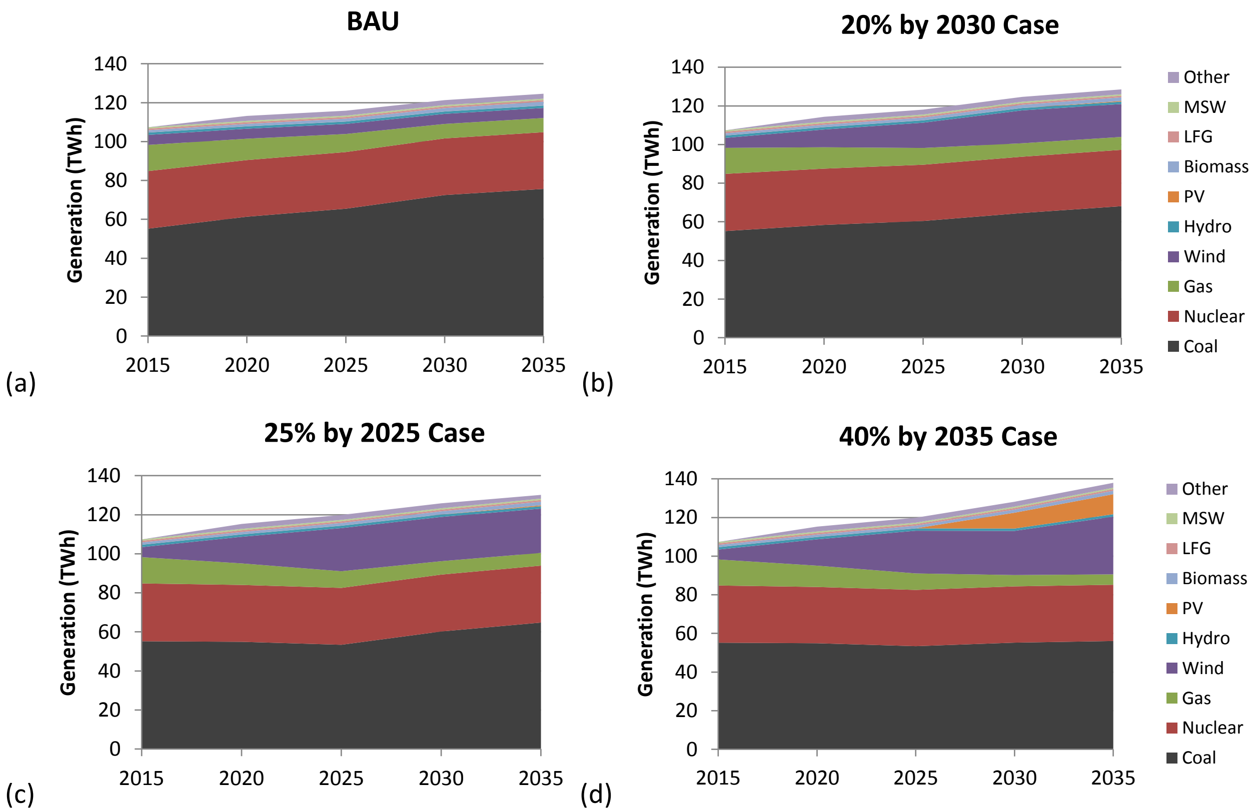
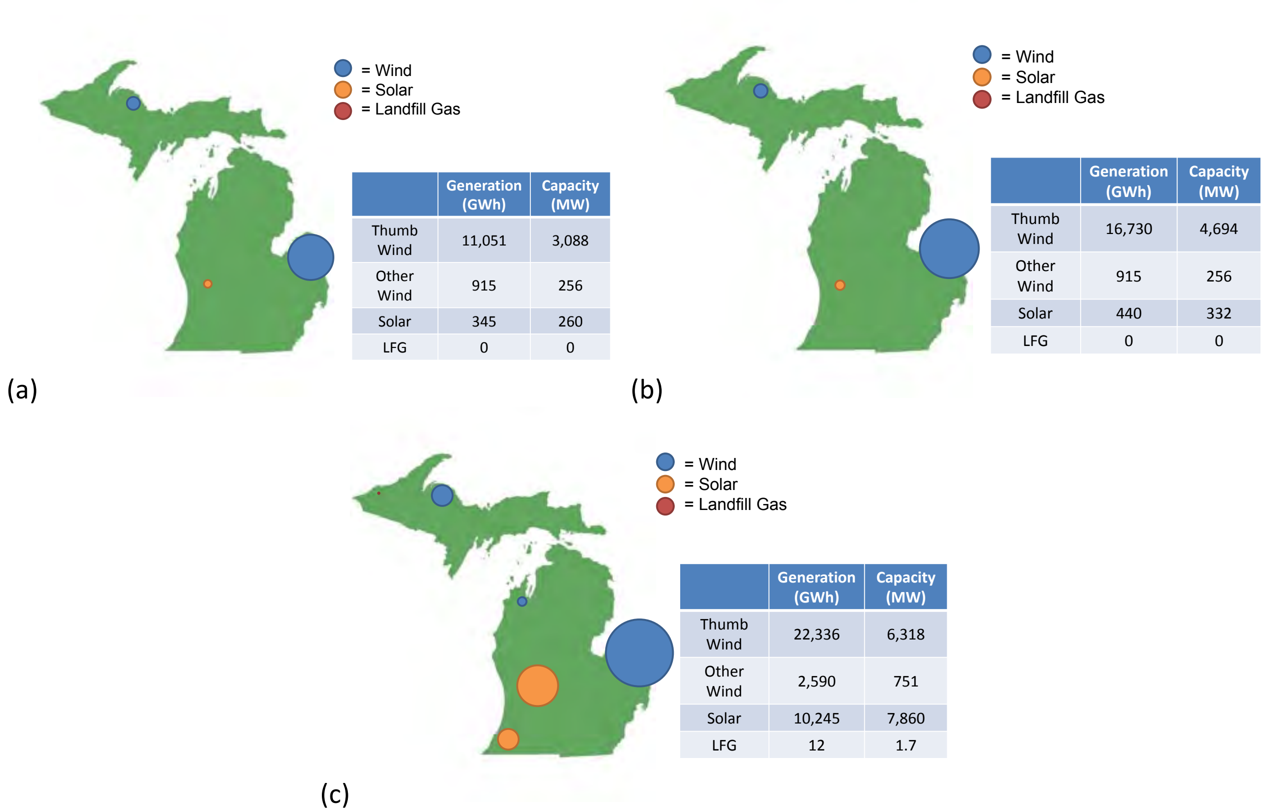


Figure 4-1: Michigan Generation Mix by RPS Scenario - (a) Business as Usual (BAU), (b) 20% by 2030 Case, (c) 25% by 2025 Case, (d) 40% by 2035 Case. Abbreviation key: LFG = landfill gas; MSW = municipal solid waste; PV = photovoltaic; RE = renewable energy.

Figure 4-1a shows the BAU case dominated by coal and nuclear, with modest contributions by natural gas and wind. By doubling the RPS target from 10% to 20% by 2030, as shown in Figure 4-1b, increased onshore wind generation displaces coal and some natural gas. Figure 4-1c shows the impact of increasing the RPS target to 25% and accelerating the timeline to reach that goal. Again, onshore wind displaces coal and some natural gas. Figure 4-1d shows the final scenario, where 40% RPS is achieved by 2035. In this scenario, utility-scale solar is selected over additional onshore wind in the final years of the study. It is interesting to note that achieving these high penetrations of renewables did not decrease coal generation in the state, but simply prevents the increase in coal generation stemming from load growth and increased net exports.

Figure 4-2 shows the installed capacity of the incremental renewables needed to meet the expanded RPS targets, with approximate locations. As shown in this figure, onshore wind in the Thumb region provides the majority of lowest cost renewable energy in all three cases. In the 40% RPS case (Figure 4-2c), solar generation makes a significant contribution (29%) to the incremental renewable generation.

The Thumb Loop transmission project, which is currently under development, will increase access to the high quality wind resources in the Thumb region of the state. This study assumes that this transmission project will be sufficient to support that wind development in the 25% case (Figure 4-13b), but additional transmission would be needed to achieve the wind penetrations found in the 40% case (Figure 4-13c). The impact of this is further explored in the "Rate Impacts" section of this report.



(a)

	Generation (GWh)	Capacity (MW)
Thumb Wind	11,051	3,088
Other Wind	915	256
Solar	345	260
LFG	0	0

(b)

	Generation (GWh)	Capacity (MW)
Thumb Wind	16,730	4,694
Other Wind	915	256
Solar	440	332
LFG	0	0

(c)

	Generation (GWh)	Capacity (MW)
Thumb Wind	22,336	6,318
Other Wind	2,590	751
Solar	10,245	7,860
LFG	12	1.7

Figure 4-2: Generation and capacity of incremental renewable energy in 2035, with approximate location of generation, for the (a) 20% by 2030 case, (b) 25% by 2025 case, and (c) 40% by 2035 case

The introduction of renewables with low-variable costs resulted in a net increase in in-state generation stemming from increased exports to neighboring states. Compared to the BAU case, the in-state generation increases by up to 3% in the 20% by 2030 case, up to 4% in the 25% by 2025 case, and up to 10% in the 40% by 2035 case. The "Neighbor RPS" sensitivity tests the impact of adjacent states adopting a 25% RPS on the same timeline as the Michigan 25% by 2025 case. This sensitivity results in a 7% net decrease of in-state generation in Michigan due to the decreased attractiveness of exports. Given the highly interconnected nature of the grid, this underscores the impact and importance of all states' actions across the region.

When compared to the base case retirement scenarios, the alternative coal retirement sensitivities yielded significantly different generation mixes, as shown in Figure 4-3. Much of the reduction in coal generation was replaced with natural gas generation, although some of the impact of the retirements was mitigated by a decrease in the net exports out of Michigan. The generation mix of new renewables is comparable to other cases, with onshore wind dominating the new additions and some solar photovoltaics contributing in the 40% case.

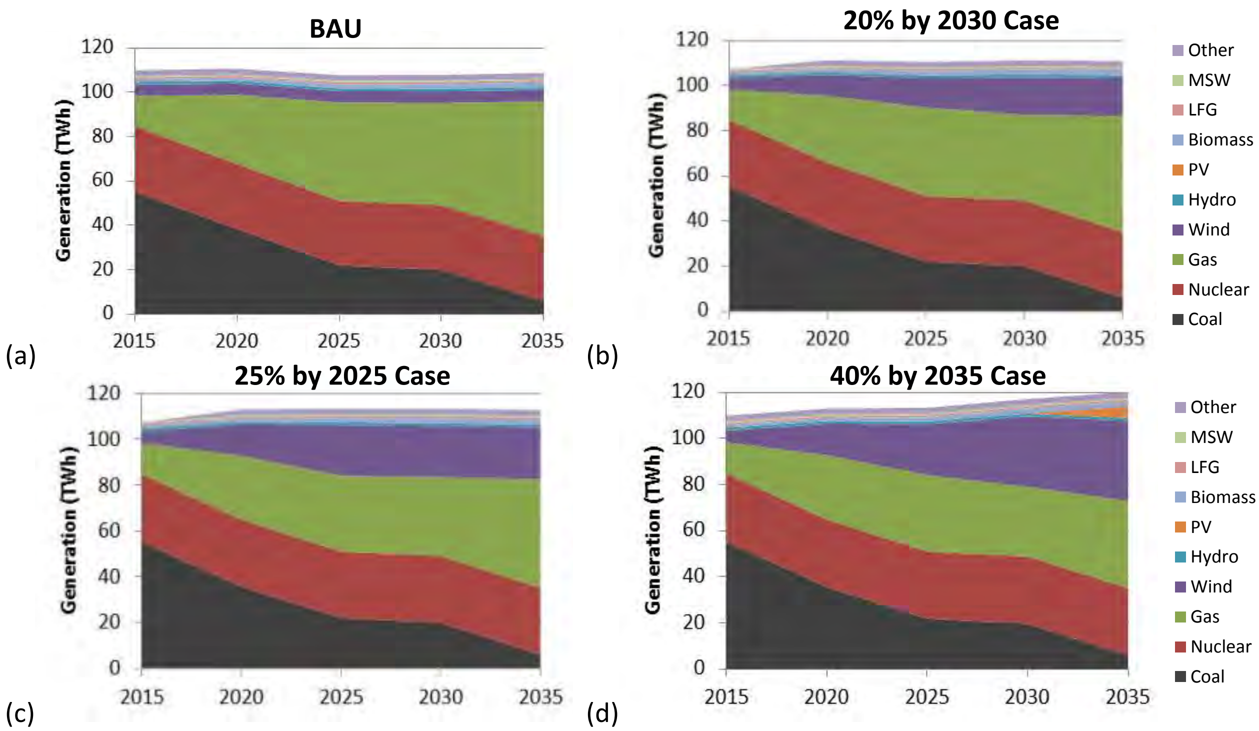


Figure 4-3: High Coal Retirement Sensitivities - Michigan Generation Mix by RPS Scenario - (a) Business as Usual (BAU), (b) 20% by 2030 Case, (c) 25% by 2025 Case, (d) 40% by 2035 Case. Abbreviation key: LFG = landfill gas; MSW = municipal solid waste; PV = photovoltaic; RE = renewable energy.

The policy variations examined – namely the solar carve out, solar multiplier, and acceptance of energy efficiency – impact the generation mix, as shown in Figure 4-4. These policy variations are tested on the 25% by 2025 case, which is shown in Figure 4-4a. While both the solar carve out (Figure 4-4b) and solar multiplier (Figure 4-4c) increase the penetration of solar, the solar multiplier results in a considerable reduction in wind generation because each megawatt-hour of solar generation is credited by three renewable energy credits. When energy efficiency is allowed to count toward the RPS (Figure 4-4c), nearly the full assumed supply of available efficiency is selected with only the most expensive measures not chosen. This reduces the amount of future onshore wind generation.

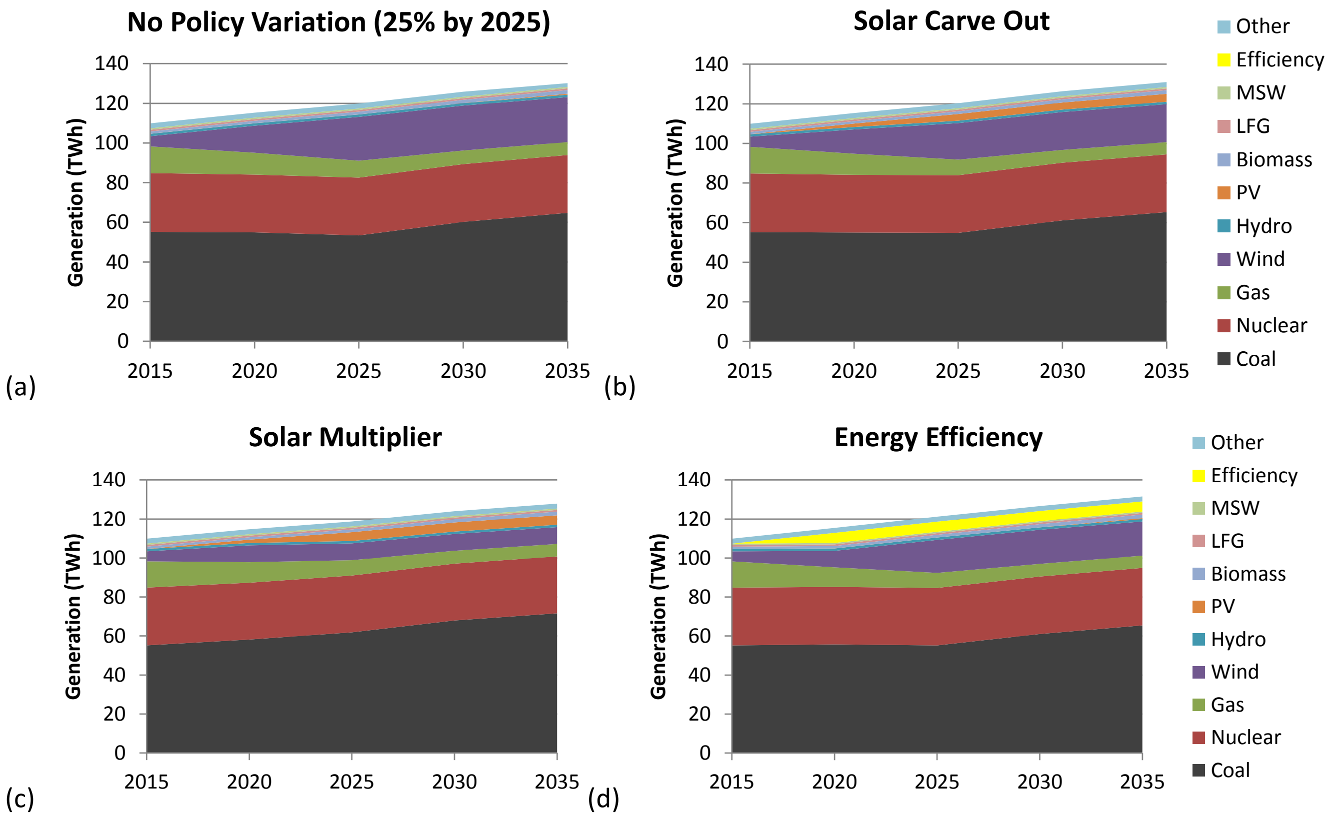


Figure 4-4: RPS Policy Variations - Michigan Generation Mix to Achieve 25% by 2025 – (a) No Policy Variation, (b) Solar Carve Out, (c) Solar Multiplier, (d) Energy Efficiency. Abbreviation key: LFG = landfill gas; MSW = municipal solid waste; PV = photovoltaic; RE = renewable energy.

The mix of generation in Michigan varied considerably for some of the sensitivities. Figure 4-5 shows this generation mix for the 13 sensitivities examined in 2025. Recall that these sensitivities are based on the 25% by 2025 case (leftmost bar in Figure 4-5), which assumes the more conservative base case assumptions for coal unit retirements.

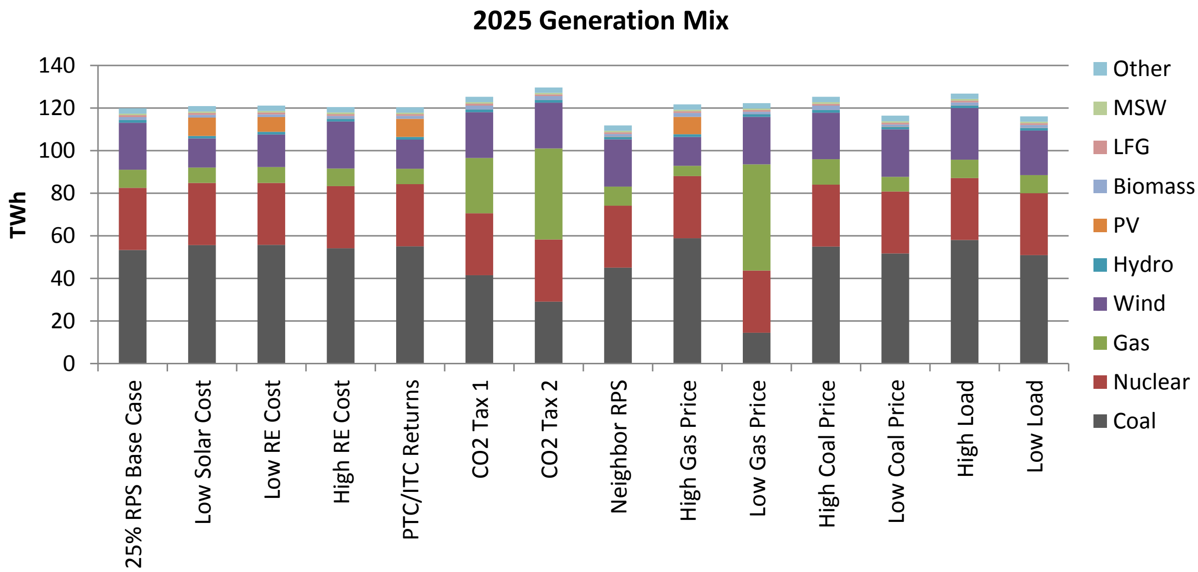


Figure 4-5: Generation Mix in 2025 for Sensitivities. Abbreviation key: LFG = landfill gas; MSW = municipal solid waste; PV = photovoltaic; RE = renewable energy.

In most of the sensitivities, the resulting generation mix is still heavily reliant on coal, with significant contribution from nuclear. Onshore wind dominates new renewable additions, but several cases resulted in significant contributions from solar PV. A few points of note:

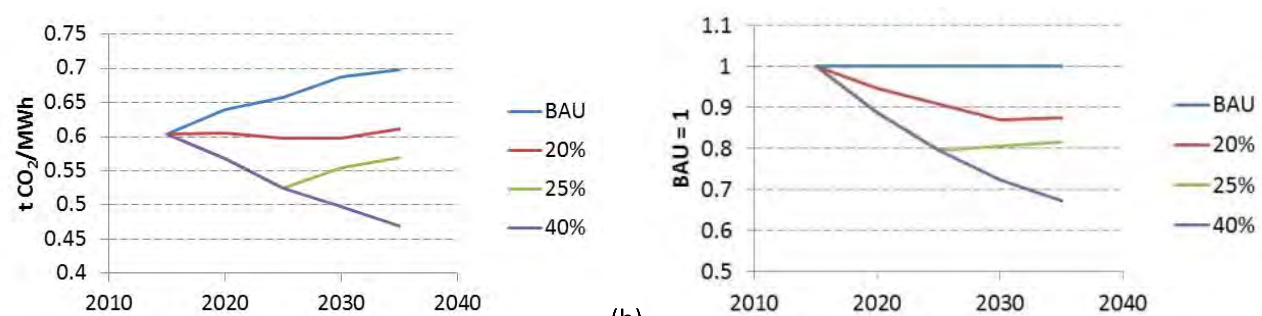
- The "Low Solar Cost" case demonstrates that setting a lower floor for the installed cost of solar ($0.50/W) yields significantly more solar generation. In 2025, this sensitivity has 32% of renewable energy coming from utility-scale solar. The "Low RE Cost" case, which assumes the same lower floor for solar cost, but also assumes less expensive onshore wind costs ($1,455/W), still results in a sizeable share of renewable energy from solar (26%). The "High RE Cost" case, which assumes installed costs of solar do not drop below $1.25/W and wind installed costs are $2,425/W, shows the lowest cost renewable option is onshore wind.
- The base case assumption is that the Production Tax Credit and Investment Tax Credit are not renewed. The "PTC/ITC Returns" case investigates the impacts of renewing these subsidies. The value of these programs proves to be greater for solar than wind, resulting in more solar generation, comparable to the "Low Solar Cost" case.
- The introduction of a CO_2 tax has several interesting impacts. First off, it increases total generation in Michigan by 4% when under the lower carbon tax value and 8% when under the higher carbon tax value, due to increased exports to neighboring zones. The CO_2 tax also leads to the substitution of natural gas for coal generation. Under the lower carbon tax, natural gas generation triples and coal generation drops by 22%. The higher carbon tax (pegged to the "social cost" of carbon) leads to a 400% increase in gas generation and a 45% decrease in coal generation. Under both of these sensitivities, nearly all of the new renewables needed to meet the expanded RPS come from onshore wind, with only a minor contribution from increased biomass output. This is driven by the fact that a carbon tax would have a greater impact on the off-peak energy prices, when coal is more likely to be on the margin and wind resources are stronger.
- In the "Neighbor RPS" case, states that border Michigan adopt a similar RPS policy (i.e., 25% by 2025), which leads to significant construction of new renewable generation in those areas. This

pushes down energy prices and makes exports from Michigan to these zones less desirable, resulting in 7% less in-state generation. Onshore wind was selected as the lowest cost option to comply with the expanded Michigan RPS. Due to the decrease in exports, this sensitivity resulted in a highest share of generation from renewable resources (23%). (Recall that the RPS is set as a function of retail sales within the state, so energy delivery losses and net exports to neighboring states do not influence the amount of renewable energy that must be procured.)

- In the "High Gas Price" sensitivity, natural gas prices reach $8.92/MMBtu (in 2013$) in 2025. This shifts some generation from natural gas to coal, while pushing up energy prices, particularly during on-peak hours. This results in more favorable conditions for solar, given the time of day profile of solar generation. With high natural gas prices, over 30% of the renewable energy to meet the expanded RPS will be sourced from solar PV, with much of the rest coming from onshore wind.
- Low natural gas prices have the opposite effect. With assumed prices of $2.92/MMBtu (in 2013$) in 2025, natural gas generation increases by over 500%, coal generation drops by 72%, and the new renewables needed to meet the expanded RPS are onshore wind. Such an increase in natural gas consumption would have a major impact on the state's natural gas market. In 2012, electric power accounted for 23% of the natural gas demand in Michigan. Such a large increase in demand from the power sector could prompt the need for expanded natural gas infrastructure.
- The results proved to be less sensitive to coal price. Under both high and low coal prices, the generation from coal remains largely unchanged and onshore wind resources are used to meet the expanded RPS.
- The load sensitivity, which varies load growth from 0 to 1.2% per year, does not result in a major impact on the results. While the magnitude of the generation is impacted, the generation mix remains mostly constant. Onshore wind resources are the lowest cost options for new wind development.

4.2. Emissions

The reductions in emissions are directly attributable to the changing generation mixes for each scenario, policy variation, and sensitivity. Figure 4-6a shows CO_2 emissions intensities for each of the four main scenarios, while Figure 4-6b shows the results relative to the Business as Usual (BAU) case.



(a) (b)

Figure 4-6: (a) Absolute and (b) Relative CO_2 Emissions Intensity for Four Scenarios - Business as Usual ("BAU"), 20% by 2030, 25% by 2025, 40% by 2035

The existing RPS for Michigan is assumed to achieve 10% renewable penetration (inclusive of existing incentives) by 2015. This is reflected in all cases. Therefore, the 20% by 2030 case adds renewables equal to 10% of retail sales; the 25% by 2025 case adds renewables equal to 15% of retail sales; and the

40% by 2035 adds renewables equal to 30% of retail sales. By the final year of the study, these three cases reduce the carbon intensity of generation by 13%, 20%, and 33%, respectively.

Carbon intensity, expressed in units of t CO_2/MWh, is a more appropriate metric to evaluate the reduction of emissions attributable to the RPS program because of the impacts of increasing and decreasing interstate trade. Because wind, and to some extent solar, are the primary resources used to meet the expanded RPS and these technologies have low variable costs, their introduction reduces marginal energy prices in Michigan and makes exports to neighboring states more attractive. In this study, the base case employs a business as usual approach for the non-Michigan regions, meaning that their existing fleet is maintained and only expanded to meet capacity reserve requirements. The impact on the overall results to this assumption are shown later in a sensitivity in which neighboring states match Michigan's RPS targets.

In addition to CO_2 emissions, the results for SO_2 and NO_x emissions are shown in Figures 4-7 and 4-8, respectively. The drop in SO_2 emissions across all cases, as shown in Figure 4-7a, is a result of compliance with the Mercury and Air Toxics Standards (MATS) for which the control technologies have the co-benefit of SO_2 reductions.

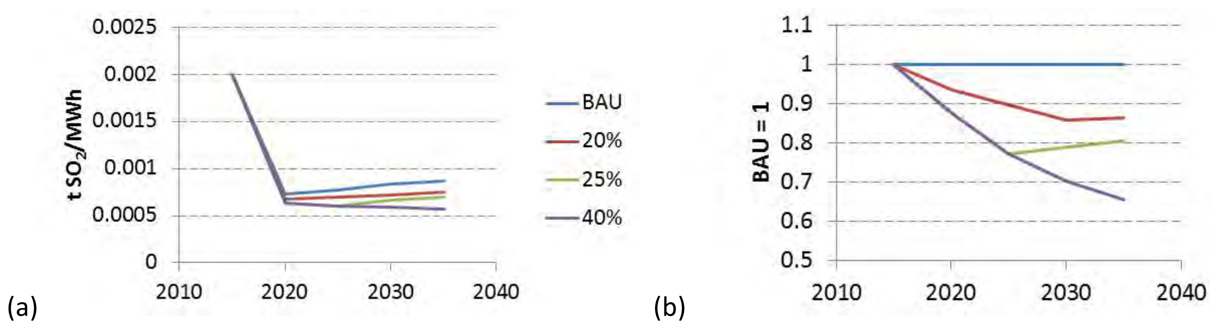


Figure 4-7: (a) Absolute and (b) Relative SO_2 Emissions Intensity for Four Scenarios - Business as Usual ("BAU"), 20% by 2030, 25% by 2025, 40% by 2035

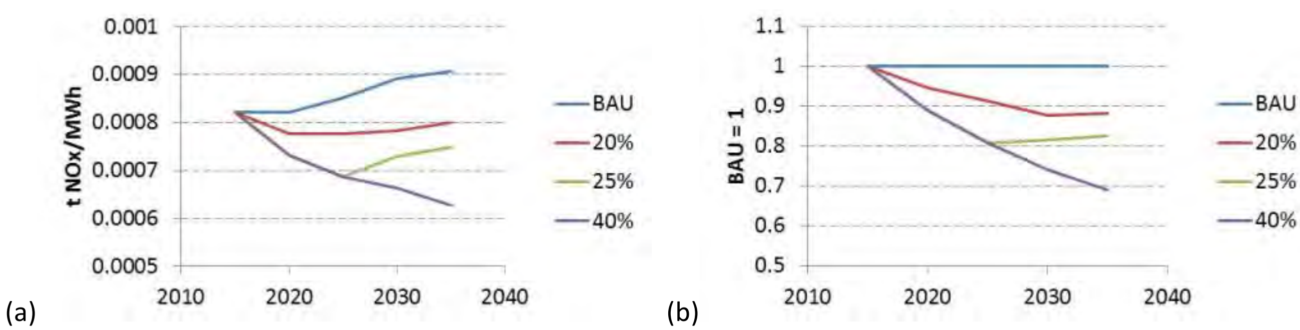


Figure 4-8: (a) Absolute and (b) Relative NO_x Emissions Intensity for Four Scenarios - Business as Usual ("BAU"), 20% by 2030, 25% by 2025, 40% by 2035

Figures 4-7 and 4-8 illustrate that the demonstrated trends of the decreasing CO_2 emissions intensity of in-state generation are largely similar to the impacts for SO_2 and NO_x. The displacement of coal generation and, to a lesser extent, natural gas generation directly relate to these reductions in emissions.

The base-case scenarios use conservative assumptions for the future retirement of coal generators. The only retirements included are those that have been announced and those for which the future costs of operating and installing control equipment to comply with the Mercury and Air Toxics Standard (MATS) exceeds the costs of a new natural gas combined cycle. This approach yielded 1.1 GW of announced retirements and 754 MW of MATS-driven retirements, which were primarily smaller coal units.

These assumptions for the magnitude of coal retirements may prove to be overly conservative, particularly in light of the EPA's proposed rules to reduce carbon emissions from existing power plants. The sensitivity of the results to the assumptions on coal unit retirements was tested by assuming coal plant retirements occur based on vintage. More specifically, in this sensitivity, coal units are retired after 50 years of operation. Units retired due to vintage are replaced by a comparable capacity of natural gas combined cycle units. The capacity of operational coal units for base case assumptions and this sensitivity is shown in Figure 4-9.

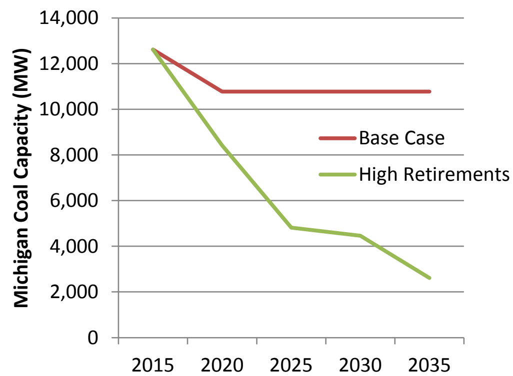


Figure 4-9: Operational Coal Capacity in Michigan: Base Case and High Retirement Sensitivity

The resulting coal unit retirements lead to significantly more natural gas generation, which serves to reduce emissions. (Per unit of fuel energy, natural gas releases approximately half as much CO_2 as coal and very little SO_2.) This reduces the potential emissions mitigation benefits upon introducing renewables through an expanded RPS, as shown in Figure 4-10.

(a)

(b)

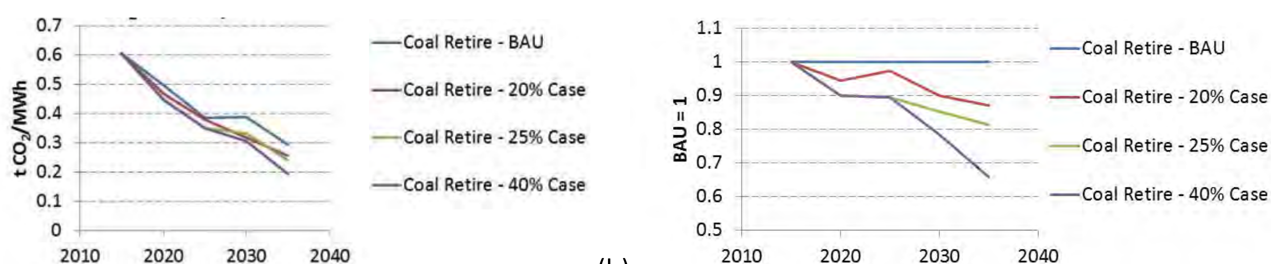
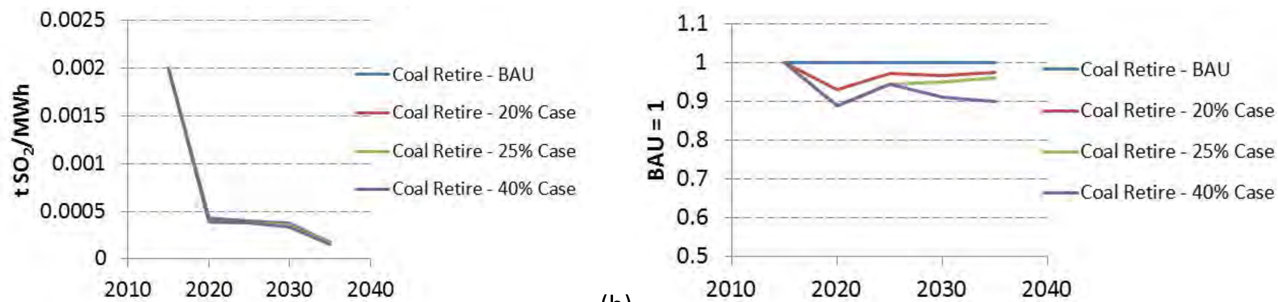


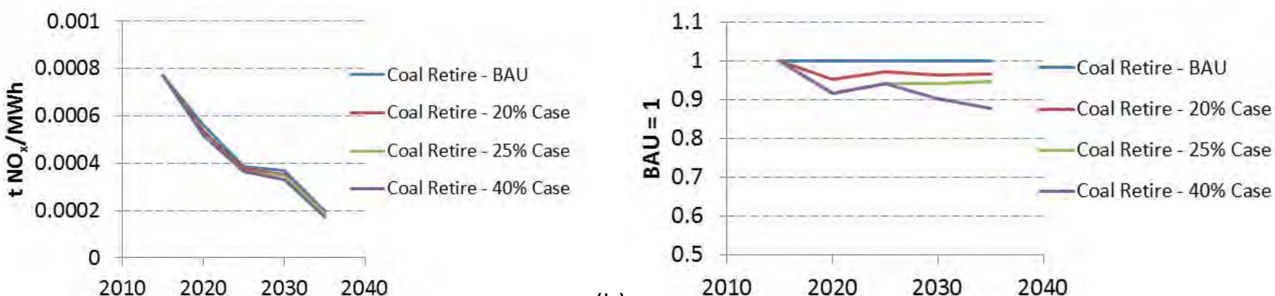
Figure 4-10: (a) Absolute and (b) Relative CO_2 Emissions Intensity for High Coal Retirement Sensitivities

As seen in Figure 4-10a, the BAU case demonstrates that the retirement of additional coal units and their replacement with efficient natural gas combined cycle units reduces Michigan's carbon intensity of generation from 0.6 t CO_2/MWh to 0.3 t CO_2/MWh. Figure 4-10b shows that the CO_2 emissions intensities relative to the "Coal Retire – BAU" case, with the 20%, 25% and 40% cases showing ultimate decreases of 13%, 19%, and 34%, respectively. It is important to note, however, that these decreases are relative to the already reduced emissions stemming from higher levels of coal retirements. Figures 4-11 and 4-12 show results for SO_2 and NO_x.



(a) (b)

Figure 4-11: (a) Absolute and (b) Relative SO_2 Emissions Intensity for High Coal Retirement Sensitivities



(a) (b)

Figure 4-12: (a) Absolute and (b) Relative NO_x Emissions Intensity for High Coal Retirement Sensitivities

For the base-case scenarios, all renewable technologies are treated equally. One megawatt-hour of solar generation contributes that same value to RPS compliance as one megawatt-hour of wind generation. Looking at RPS policies across the US, however, many states have introduced incentives or mandates for particularly technologies. To assess the impacts of these preferences, we altered the 25% by 2025 case to allow for three different policy variations: (1) a solar carve-out which requires 20% of new renewable energy come from solar; (2) a solar multiplier which awards three renewable energy credits for every unit of generation; and (3) allowing energy efficiency to contribute to the RPS targets.

Figure 4-13 shows the impact on these policy variations on the carbon intensity of generation, relative to 25% by 2025 case which isolates the impacts of these policy variations. This study finds that the solar carve-out and the allowance of energy efficiency has minimal impact on emissions intensity, while the solar multiplier results in emissions intensities increases of up to 15%. This is due to the fact that the solar carve-out and energy efficiency variations result in the addition of new renewables and efficiency equal in magnitude to the base case assumptions, while the solar multiplier serves to decrease the introduction of new renewables. By awarding triple credit to solar generation, fewer renewables are built, resulting in higher emissions rates.

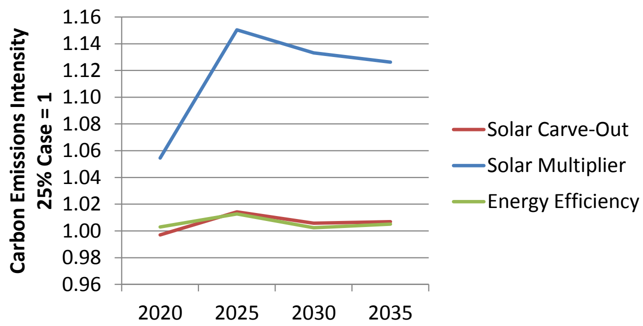


Figure 4-13: Impact of Policy Variations on CO_2 Emissions Intensity, Relative to 25% by 2025 Case

In addition to testing these policy variations, the sensitivity of the results was tested against key input assumptions. The 25% by 2025 case was evaluated under the following sensitivities:

- Low solar installed cost
- Low wind and solar installed cost ("Low RE Cost")
- High wind and solar installed cost ("High RE Cost")
- Extension of the production and investment tax credits ("PTC/ITC Returns")
- CO_2 tax at $25/t ("$CO_2$ Tax 1")
- CO_2 tax at social cost of carbon ("CO_2 Tax 2")
- Equivalent neighbor state RPS increase ("Neighbor RPS")
- Low/high natural gas price
- Low/high coal price
- Low/high load growth

Figure 4-14 shows the resulting CO_2 emissions and CO_2 emissions intensities for each of the sensitivities. With the exception of the BAU case, all sensitivities presented achieve the target of 25% renewables by 2025. Across all sensitivities, achieving this target yields considerable reductions in CO_2 emissions and CO_2 emissions intensities. Low natural gas price and the introduction of a carbon tax result in the greatest decrease in emissions, while high gas price and high load increase emissions.

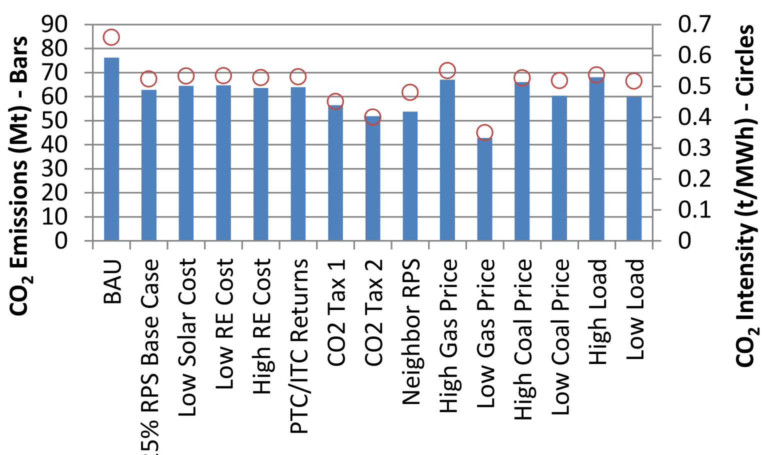


Figure 4-14: Sensitivity Analysis of CO_2 Intensity in 2025

The increase in renewable generation in Michigan changes the net import/export of electricity between Michigan and neighboring states. In the base case scenarios, Michigan increases its exports, meaning Michigan renewables displace generation outside of Michigan's borders. Therefore, to understand the CO_2 emissions impact of an expanded Michigan RPS, it is useful to measure the change in CO_2 emissions of the entire modeled geography in this study.

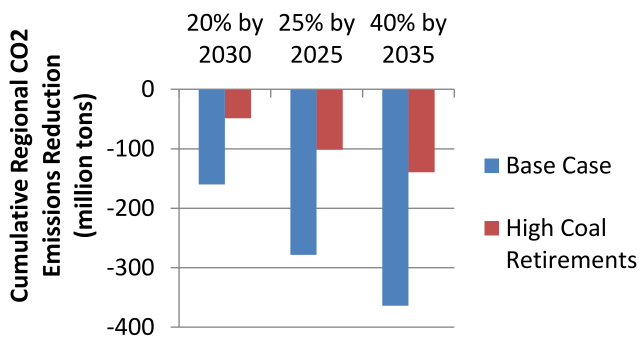


Figure 4-15: Regional Cumulative CO_2 Reductions Due to Michigan RPS

Figure 4-15 shows the change in total CO_2 emissions across the constrained geography over the 20-year study period, relative to the business as usual cases. (Figure 3-2 shows the boundaries of the constrained system, which covers all or parts of sixteen states.) Of the cumulative CO_2 emissions reductions that are attributable to an expanded Michigan RPS, between 28% and 38% of these reductions occur outside of Michigan. With the expanded RPS, Michigan is exporting more electricity and displacing local generation across the region. Two zones which border Michigan had the largest impact: MISO-IN (which covers most of Indiana) and PJM Rest of RTO (which includes Ohio and parts of Indiana).

The CO_2 emissions reduction potential of an expanded RPS is significantly reduced under the more aggressive coal retirement scenario. Renewables primarily displace natural gas under this scenario, as much of the coal fleet is retired. When compared to the base case scenarios which still have considerable coal generation, the additional CO_2 reductions due to the RPS in the high coal retirement scenarios are between 62% and 69% smaller. Under both coal retirement approaches, the 40% scenario displaces the most CO_2. However, the CO_2 reductions achieved between 10% (i.e., BAU) and 25% renewables are considerably greater than the reductions achieved between 25% and 40% renewable penetration during the 20-year study horizon. The system that results in 2035, however, indicates lower future emissions outside of the study period (i.e., the renewables built in 2035 will continue to displace fossil fuel emissions in the years following).

4.3. Rate Impacts

When considering the cost impacts of the Michigan RPS program, it is essential to consider not only the PPA costs of new renewables, but also the costs offset by their introduction. The costs of the expanded RPS program were determined for each of the scenarios, as shown in Figure 4-16. This Figure shows only the cost categories that vary from the BAU case, which are categorized as follows:

1. "New Renewable PPA" represents the contract costs of new renewable projects.
2. "Net Imports" represents the change in revenues or costs to Michigan rate payers based on changes to the amount of electricity imported or exported. A negative value demonstrates a reduction in costs to Michigan rate payers, typically through increased exports.

3. "Capacity Expansion" is the reduction in cost to procure new firm capacity associated with the assumed capacity value of renewables.
4. "Variable Cost of Generation" represents the change in production costs associated with utility-owned generation and the change in market energy costs for other generation.

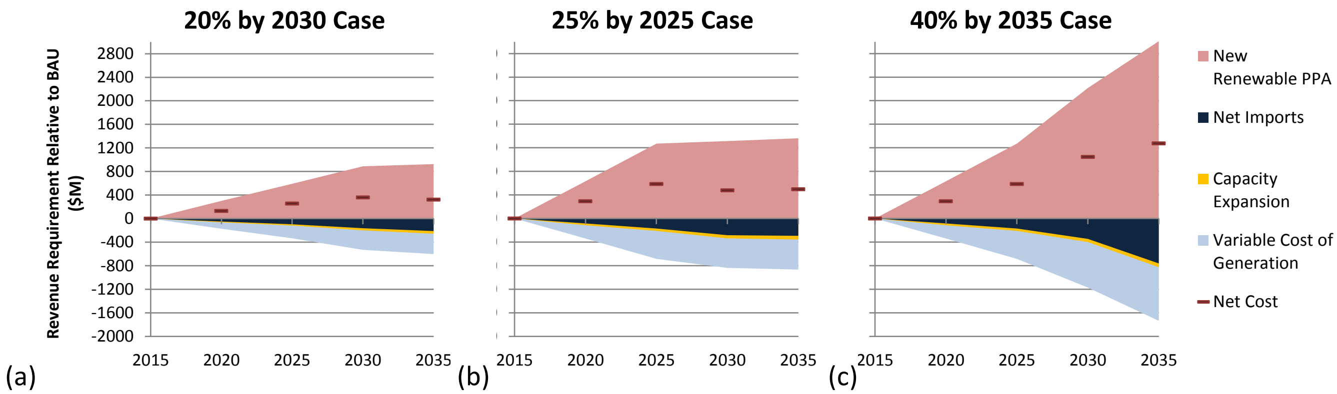


Figure 4-16: RPS Program Costs (a) 20% by 2030 Case, (b) 25% by 2025 Case, (c) 40% by 2035 Case; all values in 2013$

As shown in Figure 4-16, the most important drivers to RPS program net costs are the costs associated with new renewable PPAs and the reduction in the variable cost of other generation (e.g., reduced generation from coal and natural gas plants). PPA costs are offset by reductions totaling between 53% and 65% of the costs of the PPA.

For the 20% by 2030 case, the additional costs associated with the RPS program reach up to $360 million per year (in 2013$). The net present value (NPV) of the program costs over a 20-year horizon, discounted at 7% per year, total $1.9 billion. At the end of the study period (2035), the impacts of this program on a "typical" household that consumes 600 kWh per month would be $1.70 per month, assuming program costs are evenly divided across the demand of all utility customers. This would be less than 2% of the total bill, assuming other fixed costs remain constant.[44]

For the more ambitious RPS target of 25% by 2025, the peak incremental program costs are $590 million per year in 2025 and decrease thereafter. The NPV of program costs are $3.6 billion and the impact to the "typical" household would be $2.60 per month in 2035, a 3% increase.

The annual RPS program costs for the 40% by 2035 reach $1.27 billion in 2035, with an NPV of $5.2 billion. To achieve this penetration of renewables, in 2035, the "typical" household would see an increase of $6.70 per month, a 7% increase. In addition to these RPS program costs, additional transmission infrastructure would be needed to develop the selected wind resources in the Thumb region of the state. The Thumb Loop project is expected to increase transmission capacity to the region of the state by 5 GW at a planned installed cost of $510 million. Because the Thumb Loop project is a "Multi Value Project," its costs are spread across the MISO service territory, with Michigan residents paying approximately 20% of the costs. If one assumes that any future transmission projects needed to reach 40% renewables have similar costs per MW of new capacity as the Thumb Loop Project, and that such projects would also be deemed Multi Value Projects, Michigan rate payers would pay between $5

[44] This holds delivery charges, sales tax, and other charges constant, at rates equivalent to DTE's current charges for residential customers.

and $10 million per year for transmission upgrades needed to incorporate the wind penetrations in the 40% by 2035 case. Such costs are small compared to the values of the renewable PPAs and the offset energy costs from integrating the renewables.

The RPS program costs are largely comparable under the high coal retirement scenarios, as shown in Figure 4-18. The NPV of the program costs for the 20% by 2030, 25% by 2025, and 40% by 2035 cases are $2.8 billion, $4.0 billion, and $4.9 billion, respectively. In 2035, the RPS program costs would equate to increases for the "typical" household of $1.20 per month, $2.60 per month, and $4.70 per month, respectively.

With comparable RPS targets, the new renewable PPA costs are similar to the base case coal retirements because similar renewable projects are selected. Changes in the value of exports and the cost of the displaced variable generation drive the changes in the RPS program cost.

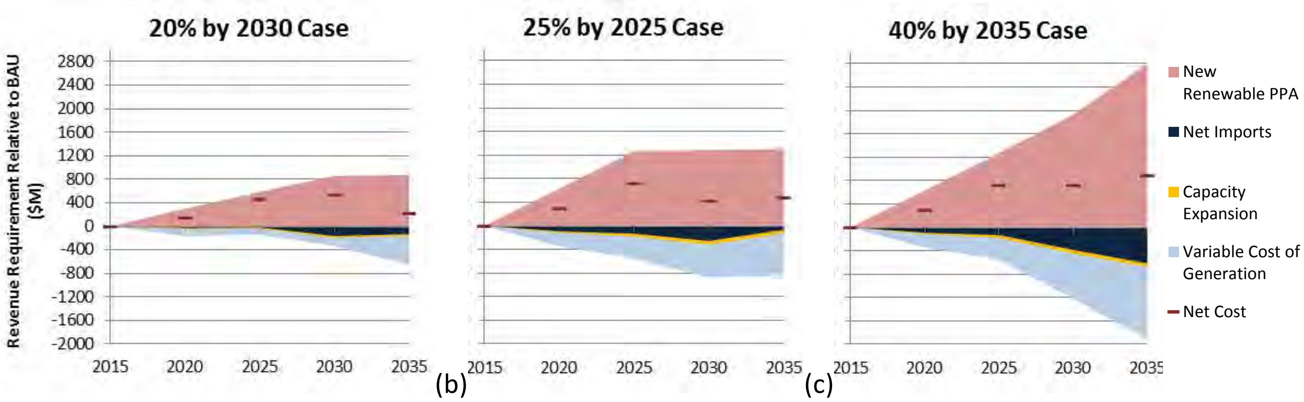


Figure 4-17: High Coal Retirement Sensitivities - RPS Program Costs (a) 20% by 2030 Case, (b) 25% by 2025 Case, (c) 40% by 2035 Case; all values in 2013$

The impacts of RPS policy design variations on system-wide revenue requirements are shown in Figure 4-18. Note that these results are presented as a change in costs relative to the "pure" 25% by 2025 case, effectively isolating the cost impacts of the policy variation.

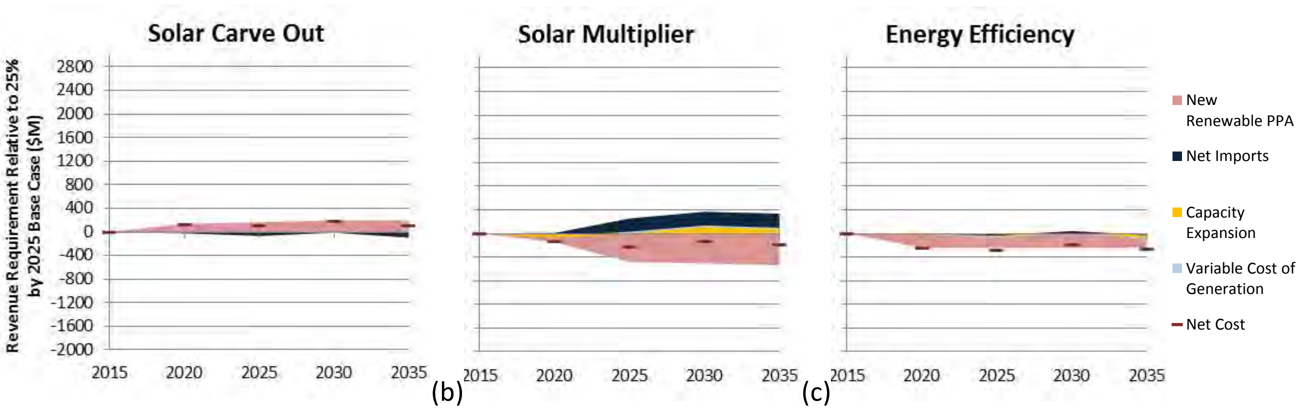


Figure 4-18: Effect of Policy Variations on RPS Program Costs (a) Solar Carve Out, (b) Solar Multiplier, (c) Energy Efficiency; all values in 2013$

As shown in Figure 4-18, incorporating a requirement for a share of the RPS to be met by solar (a solar "carve out") results in an increase in RPS program costs, due to the higher costs of utility-scale solar over onshore wind. The solar carve out increases the NPV of program costs by $1.0 billion over the 20-year study horizon.

On the other hand, the solar multiplier decreases the NPV of RPS program costs by $1.4 billion over the study horizon. This is due to the reduction in renewable energy introduced onto the system. Because three renewable energy credits are given for every megawatt-hour of solar generation, the solar multiplier reduces the amount of renewable energy generated in Michigan by 35% in the final year of the analysis.

This study found that allowing energy efficiency to meet RPS requirements reduces the NPV of the program costs by $2.0 billion over the study period. The potential for energy efficiency and the associated costs are based on a study conducted for the Michigan Public Service Commission, assuming a constrained potential supply for efficiency using the utility cost test (UCT).[45] When considering the reductions in production costs, many energy efficiency measures prove to be low or even negative cost options. Effectively incorporating energy efficiency into a standard, however, is a non-trivial endeavor. Accurately measuring the magnitude of achieved energy efficiency requires a basis for comparison (e.g., a baseline or standard assumptions for achieved reductions).

The impacts on rates in 2025 for the sensitivities are shown in Figure 4-19, relative to the RPS program costs for the 25% by 2025 case which is $5.40 per delivered MWh. These sensitivities show that there are several situations examined that can greatly reduce RPS program costs and one (high installed costs for renewables) that in significantly increase program costs.

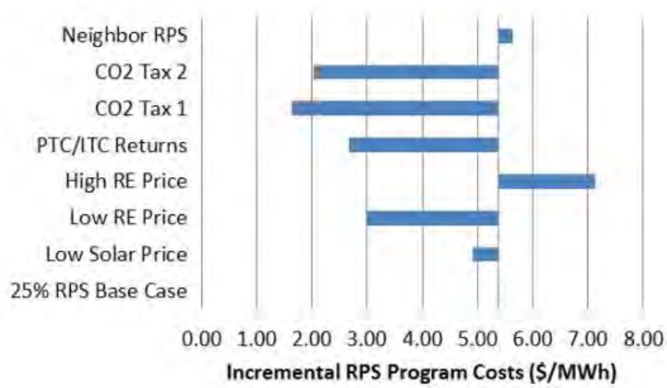


Figure 4-19: Sensitivity Analysis on RPS Program Costs

Introducing an expanded RPS in a market with a carbon tax reduces RPS program costs by two-thirds. (For the CO_2 tax sensitivities, it is assumed that the revenue collected for the CO_2 tax is fully dispersed back to rate payers.) The presence of a carbon tax increases the costs to dispatch coal and natural gas, which increases the value of energy displaced by renewables and lowers costs attributable to the expanded RPS.

[45] Michigan Public Service Commission, "Michigan Electric and Natural Gas Energy Efficiency Potential Study," November 2013.

The base case assumptions do not include major federal subsidies such as the PTC and ITC. Should the PTC and ITC be extended, the costs borne in Michigan rates for the expanded RPS would decrease by 50%.

The results on RPS program costs are fairly sensitive to the assumptions for installed costs of renewables. Higher installed costs for wind and solar resulted in a 30% increase to program costs, while lower installed costs decrease RPS program costs by 40%. Lower solar prices alone have a modest impact on RPS program costs due to the dominance of onshore wind as the lower cost renewable option.

Should neighboring states introduce comparable RPS, the impact on the cost of Michigan's RPS is small. Changes in the net imports or exports are balanced by a decrease in the amount of conventional in-state generation, netting only a small impact on the net costs attributable to the RPS program.

Figure 4-19 shows all of the RPS program cost impacts for all of the sensitivities for which their total costs are comparable to the 25% RPS base case. Sensitivities that affect fuel prices or load cannot be directly compared to the base case to isolate the impacts on RPS program costs.

5.0. Discussion

Between 1997 and 2009, there was a flurry of activity with states adopting and modifying Renewable Portfolio Standards.[46] Following the adoption of these state-level policies, renewable energy development expanded rapidly, with 46 GW of new non-hydro renewable capacity added to states with active or impending RPS obligations.[47] Approximately 85% of the RPS-driven renewable additions are wind, on an energy basis.[48] Michigan's response to the adoption of P.A. 295 mirrors the national trends: a rapid increase in renewable generation, dominated largely by onshore wind.

The marked increase in renewable generation in the U.S. since 2000 can be explained by several drivers: the adoption of binding RPS policies, improved technology performance, reduced cost, and federal subsidies such as the PTC and ITC. With the future of these federal subsidies uncertain and grid parity of cost for renewables not yet achieved in most regions, RPS-driven demand will likely serve as a key driver for near-term renewable development.

Across the U.S., the outstanding RPS obligations would require over 90 GW of new renewable energy development by 2035, assuming current RPS targets are met.[49] Recent events, however, suggest that expanding state-level renewable targets may be difficult. In Michigan, the failure of Proposition 3 in 2012 will leave the state with no unmet RPS demand after 2015. In June 2014, Ohio became the first state to "freeze" their RPS, delaying the renewable targets by two years. This action not only impacted the market for renewables in Ohio, but it also impacted the value of RECs in neighboring states where renewable developers may sell into the Ohio market.

When considering an expanded RPS for Michigan, it is valuable to clearly articulate the objectives of the policy. The most commonly cited motivations for such a policy are reducing environmental impacts, decreasing retail price volatility, and stimulating the local economy through "green jobs." This study does not address the impacts of an expanded RPS on employment, but the results of the analysis provide detail on new generation development and fuel consumption could be used as inputs for such a study. The expanded RPS's impacts on emissions and exposure to fuel price volatility are discussed below.

This study found that the expansion of Michigan's RPS would decrease air emissions under every scenario, policy variation, and sensitivity. Increasing renewable penetrations from 10% to 20%, 25%, and 40% would decrease the carbon intensity of Michigan generation by 13%, 20%, and 33%, respectively. For each of these scenarios, meeting load with an additional 1% of renewables decreases the carbon intensity by more than 1%. This is due to the displacement of coal generation, which has an emissions factor greater than the state's average. The reduction of SO_2 and NO_x follows a similar trend.

The impacts of emissions reductions driven by an expanded RPS persist across a wide range of future assumptions. For the 25% by 2025 case, each sensitivity tested resulted in significant reductions in absolute emissions and emissions intensity of generation. This held true for a range of installed costs for new renewables, as well as high and low natural gas prices, coal prices, and load. The introduction of a solar multiplier, which decreases the amount of renewable generation that would be needed to

[46] Barbose, G. "Renewables Portfolio Standards in the United States: A Status Update," State-Federal RPS Collaborative National Summit on RPS, Washington, D.C., 2013.
[47] Ibid.
[48] Ibid.
[49] Ibid.

meet RPS targets, greatly reduces the potential for emissions mitigation compared to the alternative without such an incentive.

If one attributes the full cost of the RPS program to CO_2 mitigation, the cost to reduce Michigan's emissions in the 20% by 2030 case is $36/t CO_2 in 2030. Achieving 25% renewables in 2025 costs $40/t CO_2 emissions reduced, while 40% by 2035 costs $49/t CO_2. These costs do not include the potential value of federal tax credits including the PTC and ITC. Should the PTC and ITC continue for the study period, the costs of carbon mitigation borne through Michigan electric rates would decrease by approximately 50%. Including the impact of emissions reductions across the region (i.e., in Indiana and Ohio), as driven by Michigan's RPS, yields lower costs of mitigation: $28/t CO_2 in 2030 for the 20% case; $33/t CO_2 in 2025 for the 25% case; and $34/t CO_2 in 2035 for the 40% case.

The costs of CO_2 mitigation from an RPS program are also influenced by the fundamental system assumptions such as coal unit retirements. In the high coal retirement sensitivities, a considerable share of coal generation is displaced by natural gas. Because natural gas generation emits roughly half as much CO_2 as coal generation, the expansion of the RPS on a gas-heavy system will have a smaller potential for emissions mitigation and higher costs per unit of mitigation.

The findings on the cost per unit of CO_2 mitigated provide a useful, but incomplete, metric to evaluate the cost effectiveness of expanding Michigan's RPS to achieve environmental goals. Assuming that the full incremental costs of the expanded RPS program are attributable to carbon mitigation fails to recognize other benefits, such as the reduction of criteria pollutants and decreased price volatility. That said, this metric is useful when comparing the cost of expanding renewables to reduce CO_2 emissions against other alternatives, such as coal to natural gas fuel switching and energy efficiency.

This is particularly important in light of the EPA's proposed rules to mitigate CO_2 emissions from existing power plants, under authority from the Clean Air Act Section 111(d), termed the "Clean Power Plan." The details of the Clean Power Plan will be more certain after the EPA's rule is finalized and State Implementation Plans are approved. Under the proposed rules, the CO_2 intensity of fossil fuel generation in Michigan should decrease by 36% by 2030 relative to 2012 fossil fuel emissions intensities, under the "Option 1" reduction schedule. The CO_2 intensities measured in the Clean Power Plan, however, are not the system-wide emissions intensities, inclusive of existing non-emitting sources (i.e., nuclear and renewables).

Using the EPA's methodology for calculating CO_2 intensity, in 2030, Michigan's expanded RPS programs would reduce CO_2 intensity relative to the BAU case by 14%, 21%, and 29% for the 20% by 2030, 25% by 2025, and 40% by 2035 cases, respectively. However, without any action, the BAU case alone results in an increase in the emissions intensity by 11% in 2030. In short, we find that the three levels of expanded RPS would meet 33%, 49%, and 69% of the difference between the EPA's proposed emissions intensity targets under Option 1 and the expected carbon intensity of the BAU case.

The environmental impacts from power generation are not limited to end-of-pipe air emissions. The extraction and processing of fuels also creates a significant burden. Using base case assumptions for coal unit retirements, in 2035, annual coal consumption in Michigan would be reduced by 5.8 million tons by expanding the RPS to reach 20%. A 25% goal would yield an annual reduction in coal consumption of 8.7 million tons, while a 40% RPS would reduce coal consumption by 14.8 million tons. Natural gas consumption is far less impacted by the expansion of Michigan's RPS, except under the high coal retirement sensitivities. In those sensitivities, successfully reaching a 20%, 25%, and 40% RPS reduces natural gas consumption by 60x10^6 MMBtu, 86x10^6 MMBtu, and 149x10^6 MMBtu per year, respectively.

Fuel expenses, namely coal and natural gas, make up a considerable share of the system-wide revenue requirements paid by electricity consumers. These fuels, and in particular natural gas, have been subject to considerable price volatility, leaving rate payers exposed to unexpected rate increases. Figure 5-1 shows the share of generation that is not meaningfully exposed to fuel price volatility, which includes nuclear, wind, and solar generation. The increase in the share of such resources would dampen the impact of spikes in the price of natural gas or coal and provide more certainty in customers' bills. In addition, these resources would not leave customers exposed to future costs of carbon, should Michigan participate in a cap and trade program or institute a carbon tax.

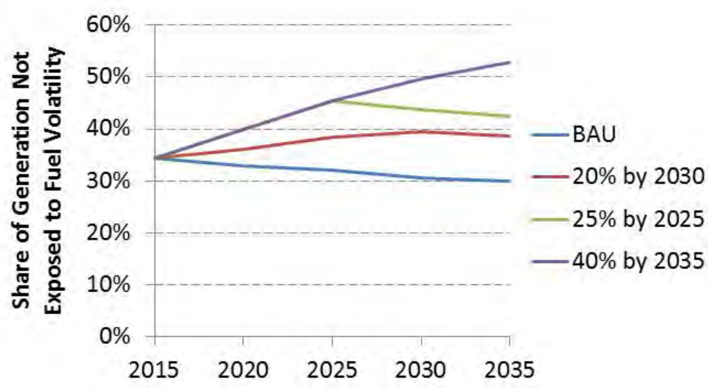


Figure 5-1: Share of Generation Not Exposed to Fuel Price Volatility

Under base case assumptions, the RPS expansion would cost $1.70/month for the 20% RPS case and $2.60/month for the 25% case for the typical residential consumer using 600 kWh per month. These cases yield significant emissions reductions at costs to consumers that are far smaller than many recent fuel price variations. Efforts to keep coal plants operational and in environmental compliance can also lead to comparable costs to rate payers. For example, in Ohio, AEP requested guaranteed income for four coal plants if operating costs exceed market value. The plan is estimated to cost $2 per month for a typical household. [50]

An expanded RPS can be one key element of a successful program to reduce CO_2 emissions. The RPS targets investigated in this study show that renewables could readily meet between one-third and two-thirds of the emissions reductions required under the proposed targets for EPA's Clean Power Plan. These new renewables could be a key component of a larger portfolio of mitigation measures including improved efficiency at coal plants, coal to gas switching, and energy efficiency. The benefits from emissions reduction and decreased price volatility make a compelling case for an expanded RPS in Michigan. The results of this study, particularly in light of Michigan's implementation of the original RPS goal of 10% by 2015, demonstrate the potential to fundamentally improve the environmental performance of its power sector in a cost-effective manner.

[50] D. Gearino, "AEP asks PUCO for income guarantee for 4 coal-fired plants," Columbus Dispatch, October 6, 2014.