Wisconsin's CO_2 Reduction Options

An Initial Analysis of CO_2 Reduction Strategies to Meet EPA Targets

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ABSTRACT

This working paper analyzes two strategies that Wisconsin could pursue in order to achieve compliance with the US Environmental Protection Agency's (EPA) proposed Clean Power Plan. Two energy modeling tools were used to compare a fuel switching strategy that displaces large amounts of coal-fired generation by 2030 against a scenario were Wisconsin implements a 30% Renewable Portfolio Standard (RPS) over the same time period. These preliminary results will be submitted for consideration by the Wisconsin Department of Natural Resources, the Public Service Commission, the US EPA, and any other stakeholders interested in exploring collaborative solutions to reduce greenhouse gas emissions from the electric power sector.

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Executive Summary

The US Environmental Protection Agency (EPA) is in the process of crafting the nation's first regulations to curb CO_2 emissions from existing fossil fuel-fired power plants. The proposed Clean Power Plan grants states a high degree of flexibility in meeting emissions reductions goals, including the use of renewables and energy efficiency programs to reduce the overall carbon intensity (lb/MWh) of the state's electricity mix. The most straight forward compliance strategy appears to be fuel switching, phasing out older coal-fired power plants by increasing electricity generation at existing natural gas-fired power plants. However, this strategy increases utility and ratepayer exposure to historically volatile fuel prices, and may result in greater emissions of fugitive methane from the natural gas distribution network.

This analysis compares a business-as-usual (BAU) scenario against a natural gas fuel switching, scenario, and a 30% Renewable Portfolio Standard (RPS) to determine which strategy achieves the greatest emission reductions at the lowest cost. The scenarios were compared using a spreadsheet model and the MyPower modeling software developed by researchers at the Wisconsin Energy Institute(WEI).[1] Both models show that the 30% RPS can reduce Wisconsin's CO_2 emissions below EPA's targets, at a lower cost than the fuel switching scenario. These results were shown under conditions where fossil fuel prices rise steadily at 2% annually, and a scenario where natural gas prices reflect historical volatility observed from 19998-2013. The 30% RPS produced lower costs than the fuel switching scenario under each simulation, illustrating the value of renewables as a hedge against price volatility.

The results of both modeling exercises mirror results of recent analysis performed at the national level by the Union of Concerned Scientists (UCS).[2] The UCS analysis found that EPA's proposed rule "significantly underestimates" the role of renewables in establishing state-level emissions targets, and fails to reflect the falling cost of renewables. The UCS analysis found that ramping up renewable energy deployment to 23% by 2030, compared to 12% of total retail sales under the proposed rule, would increase average electricity prices by just 0.3% per year above a business-as-usual (BAU) scenario. The UCS results are even more favorable than the results of modeling for the state of Wisconsin. The evidence for supporting an aggressive shift to renewable electricity generation in Wisconsin, and across the nation, is clear. Wisconsin has an opportunity to stimulate local economic growth and energy independence, or the state could take the easier path and risk locking in decades of higher energy prices without cutting harmful greenhouse gas emissions.

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[1] Meier, Paul. "MyPower Methodology and Documentation." Wisconsin Energy Institute (link).

[2] Union of Concerned Scientists. "Strengthening EPA's Clean Power Plan." October 2014 (link).

Wisconsin's Options for EPA Carbon Compliance

This analysis of Wisconsin's electric power sector compares two strategies for achieving compliance with the US Environmental Protection Agency's (EPA) CO_2 reduction goals under the framework proposed by the Clean Power Plan, which was issued in June 2014.[3] The analysis examines two potential compliance strategies against a business-as-usual (BAU) scenario to determine which strategy achieves the greatest CO_2 reductions at the lowest cost to electricity generators and their ratepayers.

The analysis compares a scenario where Wisconsin increases it's Renewable Portfolio Standard (RPS) from 10% by 2015, to 30% by 2030 to coincide with the final compliance date under the Clean Power Plan, against a scenario where the necessary CO_2 reductions are achieved by displacing coal-fired generation with increased dispatch of existing natural gas-fired units. These two strategies are examined using two models; the Wisconsin Energy Institute's (WEI) MyPower model, and a spreadsheet-based model developed using data contained in EPA's Technical Support Documents (TSD). In addition to examining the strategies' ability to achieve compliance with the Clean Power Plan, the analysis attempts to quantify the impact on residential electricity prices, and examines policy changes that could help facilitate a shift toward a cleaner electricity mix with distributed energy resources (DER) playing a major role.

Due to time constraints imposed by EPA's deadline for public comments (December 1, 2014), sensitivity analysis was not performed for the multitude of variables that can affect emissions levels and compliance costs. The analysis also does not consider electric reliability impacts. Future research can use this analysis as a starting point for more complex work aimed at addressing reliability concerns, fuel supply constraints, and other issues not considered here.

Assumptions & Methodology:

The spreadsheet model is based on EIA Form 860, 861 and 923 data for 2012 (the most recent year available). The datasets provide nameplate capacity (MW), annual generation (MWh), and fuel consumption (mmBtu) for all utility-owned electric generating units in Wisconsin. Data for power plants with multiple units was combined to create a plant wide total. Some power plants use a mixture of fuel (mainly coal and a mixture of biomass and fuel oil), so the aggregate total reflect the dominant fuel type for each plant. The MyPower model boasts greater detail down to the unit level.

[3] The analysis is based on 2012 eGrid data provided in EPA's TSD, fuel receipts and emissions data from the Energy Information Administration's (EIA) Forms 860, 861 and 923.

Carbon Intensity

Coal, natural gas and petroleum-fired power plants were each assigned a fleet-wide CO_2 intensity factor (lb/MWh) for that specific fuel type based on 2012 data. Therefore, each coal plant was assigned a CO_2 intensity of 2,156 lb/MWh, natural gas was assigned a value of 904 lb/MWh, and oil-fired units were assigned a value of 3,758 lb/MWh. It is possible to assign unique CO_2 intensity factors to specific plants using data from EPA's Clean Air Markets Division, but the fleet-wide average for 2012 was used to reduce complexity due to time constraints. These average CO_2 intensity values are held constant in each year from 2015-2030. This is an area where future analysis could examine the impact of increased efficiency, which is one of the four "building blocks" EPA included in the Clean Power Plan.

Base Case Scenario

Under the BAU scenario, each plant's generation for 2012 was divided by that year's total to calculate each plant's share of Wisconsin's total electricity generation. These percentages were then held constant for all wind, hydro, biogas, and biomass plants for years 2013-2030. This means that no new capacity is brought online and the generation at each plant increases by the annual demand growth rate, which is set at 0.5% to reflect relatively flat growth over the past 5-10 years, and the forecasted growth rate from the 2014 Strategic Energy Assessment (WI PSC).

The 560MW Kewaunee nuclear station is shutdown after 2013 and it's share of total statewide generation (about 7.1% based on 2012 data) is split between 18 coal and natural gas-fired power plants. This method results in Kewaunee's 4.5 million MWh being split between 12 gas-fired plants larger than 250MW and six coal plants larger than 500MW. Each of these 18 plants generates an additions 252,000MWh in 2014 to make up for the closure of Kewaunee. No new renewable capacity is brought online in the BAU scenario, although this could be adjusted to reflect recent growth in wind and solar capacity. The MyPower simulation includes new wind resources that become available in 2014 to reflect utility's renewable energy purchases to meet RPS compliance heading into 2014 and 2015.

Estimated Fuel Costs

The price of coal is set at $35/short ton, natural gas is set at $5/mcf, and fuel oil is set at $95/barrel. These prices are based on the most recent EIA data (as of October 2014) and each price is set to increase at 2% annually to reflect inflation. The price of biomass is set at $100/MWh, biogas is set at $100/MWh, hydro is set at $20/MWh, wind is set at $50/MWh to reflect recent power purchase agreements (PPAs). The price of solar is set at $80/MWh to reflect the price of PPAs signed by utilities in other states (Bollinger 2014). Fuel costs are then multiplied by the associated generation type and fuel consumption factor (fuel/MWh) to produce a total annual fuel/generation cost for the state of Wisconsin.

Both compliance strategies were simulated with stable natural gas prices described above, and with historical prices from 1999-2014 to examine the impact of price volatility on fuel costs and retail electricity prices. The natural gas prices follow the pattern observed from 1999-2014 over the 15-year period from 2015-2030. This approach is designed to highlight the financial vulnerability electric utilities could face if they rely heavily on natural gas-fired units to comply with the Clean Power Plan. It also illustrates the value of renewables as a hedge against unpredictable fuel costs that are a major component of higher prices for end user customers.

Retail Electric Prices

Total fuel/generation costs in 2012 were calculated to be $3.2 billion using the MyPower model and the prices defined above. This translates into a marginal fuel/generation cost of 3.8 cents/kWh, or 28.7% of Wisconsin's average retail price of 13.2 cents/kWh for residential customers in 2012. This same method is used for 2014 with retail rates of 14.5 cents/kWh. Estimated retail rates are calculated by adding the year-over-year increase in fuel/generation costs to the previous year's retail rate. This is a simplified approach to predicting retail electricity prices, and it does not consider regulatory lags, cost recovery mechanisms, and rate cases that coincide to determine actual rates.

The estimates produced from this analysis reflect a hypothetical world where retail electricity prices are dynamically tied to prices in the wholesale (MISO) market. Commonwealth Edison operates a real-time retail electricity market in the Chicago area, and other utilities are also experimenting with real-time markets that more closely resemble the approach used here. Wisconsin utilities offer time-of-use rates, but none offer real-time, dynamic pricing for residential customers. A transition to a dynamic distribution system (DDS), discussed earlier in this paper, discusses the potential benefits for both utilities and ratepayers of moving toward real-time pricing in the retail market.

Energy Efficiency Calculations

Energy efficiency measures are incorporated into the spreadsheet model as a percentage of BAU demand. In both the fuel switching and 30% RPS scenario, energy efficiency is set at 0.2% of baseline demand in each year from 2014-2030. Thus, the baseline demand in the BAU scenario is reduced by 0.2% and supply-side resources are used to meet the resulting demand after "negawatts" are subtracted. Energy efficiency measures and demand side management (DSM) programs comprise a second "building block" under the Clean Power Plan. EPA's initial analysis determined that Wisconsin could achieve reductions of 4.7% from baseline demand in 2020, expanding to 11.8% by 2030. Energy efficiency measures are assigned a cost of $33/MWh saved in the spreadsheet model based on a research done by the American Council for an Energy Efficient Economy.[4]

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[4] Friedrich (2009). Saving Energy Cost Effectively. ACEEE, 29 September 2009 (link).

Natural Gas Fuel Switching Scenario

Under this scenario, Wisconsin generators reduce coal generation at each coal-fired power plant by 4.5% annually to meet EPA's carbon reduction targets. The targets are set at 1,293 lb/MWh averages across 2020-2029 and 1,203 lb/MWh for 2030 and beyond. The declining coal-fired generation can be replaced by a combination of renewables, natural gas, and energy efficiency. Under the fuel-switching scenario, no new renewables are brought online and the generation shortfall is filled by ramping up production from existing natural gas plants larger than 50MW. By 2030, the 23 gas-fired power plants larger than 50MW are operating at annual capacity factors of nearly 60%, compared to 27% in 2014.

The result of this heavy shift from coal to natural gas causes coal to decline from 51% of Wisconsin's total generation in 2012-2014 to 24% in 2030, while natural gas increase from 18% to over 54%. The closure of the Kewaunee nuclear plant in 2013 reduces nuclear generation from 22% in 2012 to 16% in 2030. Renewables (wind, solar, biomass, biogas and hydro) hold steady at 6% of total generation. This strategy results in an average CO_2 intensity of 1,301 lb/MWh from 2020-2029 and 1,191 lb/MWh in 2030 as shown in Figure 1. The strategy results in cumulative CO_2 reductions of 141.6 million tons from 2015-2030, or 9.4 million tons per year compared to the BAU scenario. Total generation costs increase from $3.13 billion in 2030under the BAU scenario ($46.91/MWh) to $4.06 billion ($60.95/MWh) under the fuel switching scenario.

Figure 1: Wisconsin's Carbon Intensity 2005-2030

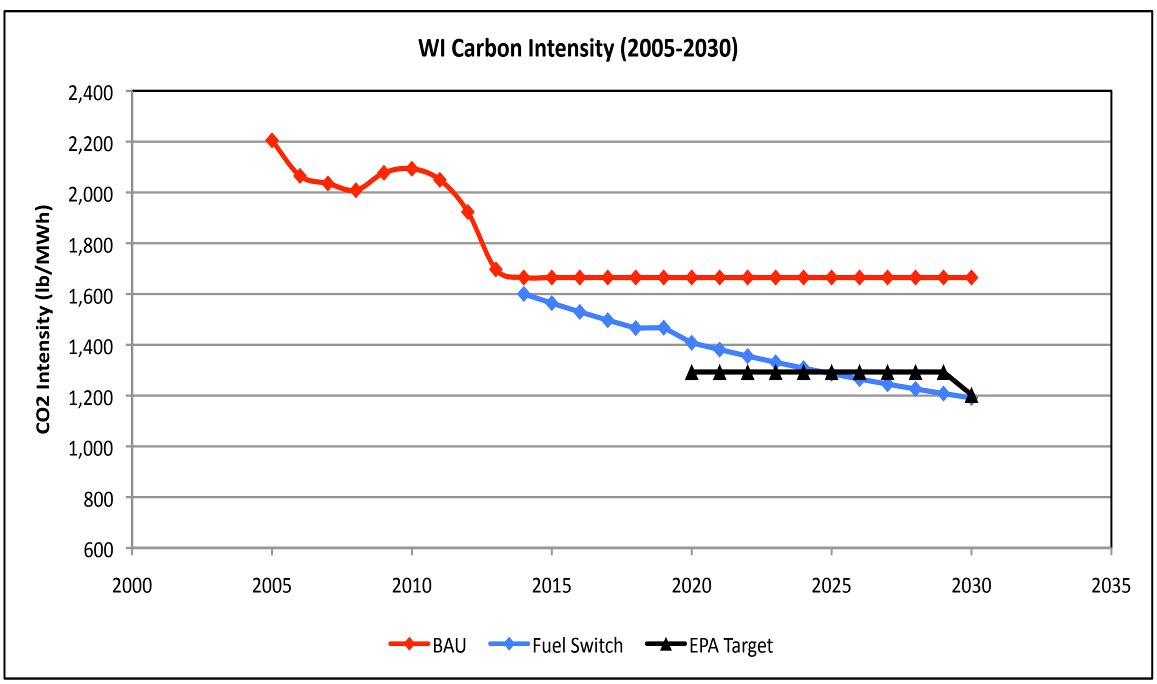
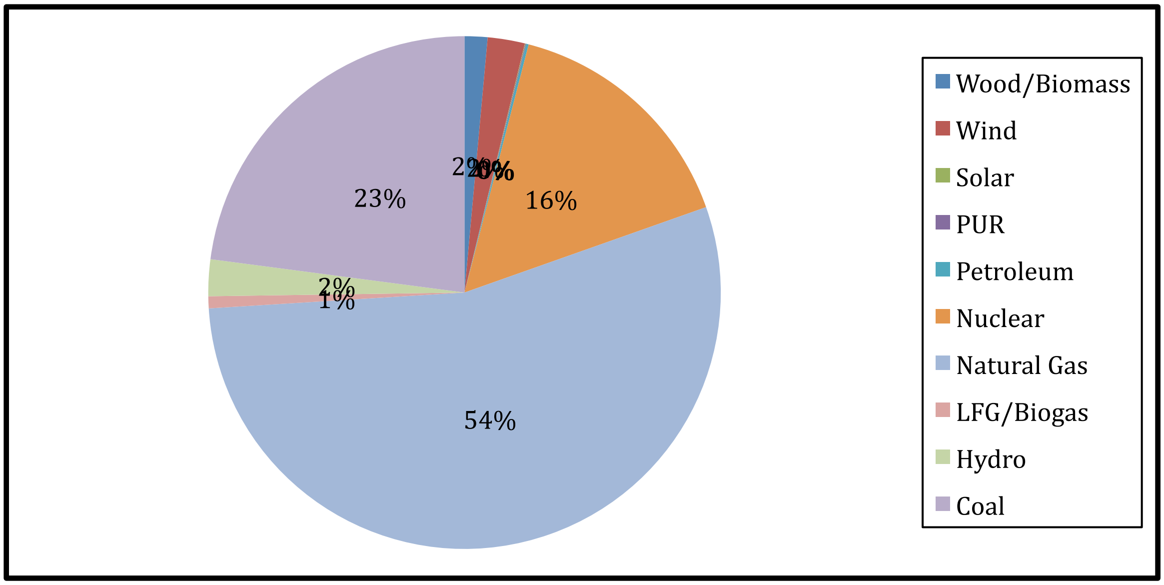


Figure 2: Wisconsin's Generation Mix in 2030



The impact of the fuel-switching scenario is dramatic. Estimated residential electricity rates rise from 14.5 cents/kWh in 2014 to 23.3 cents/kWh in 2030 as natural gas gains market share and fuel prices increase steadily. Adding a $10/ton price on CO2 pushes retail price up to 24.9 cents/kWh under the fuel switching scenario and 23.3 cents/kWh under the BAU scenario.

Figure 3: Retail Rates, BAU vs. Fuel Switching

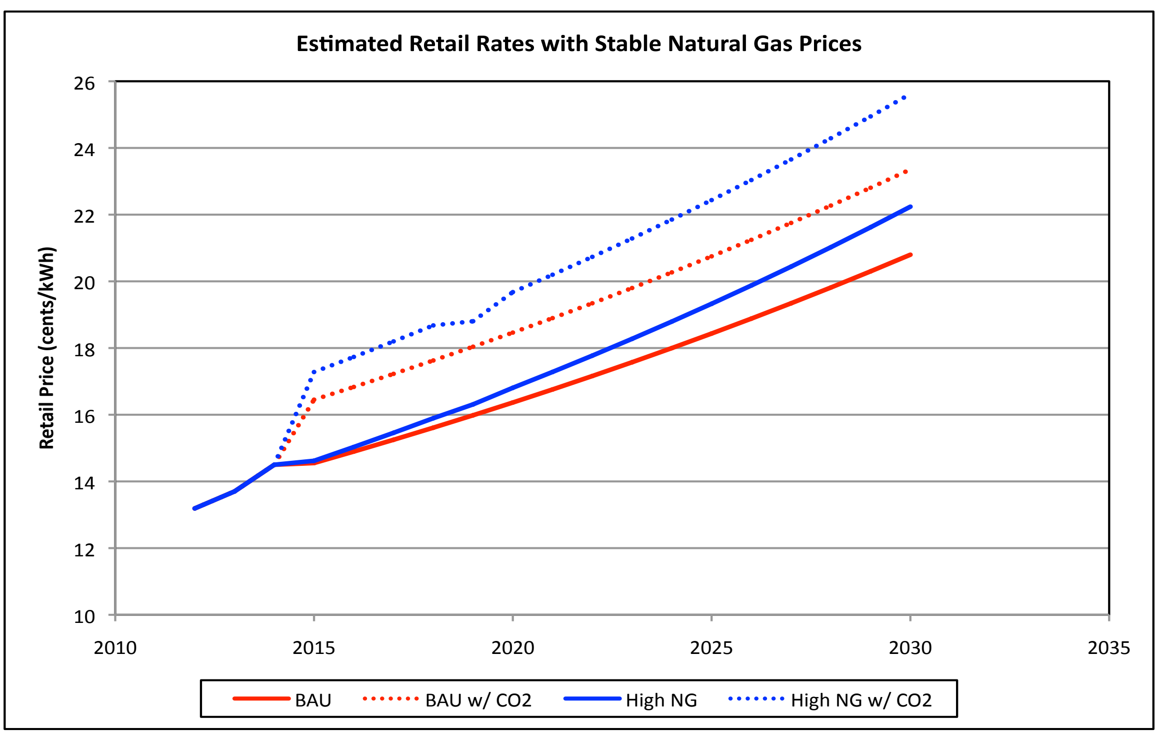
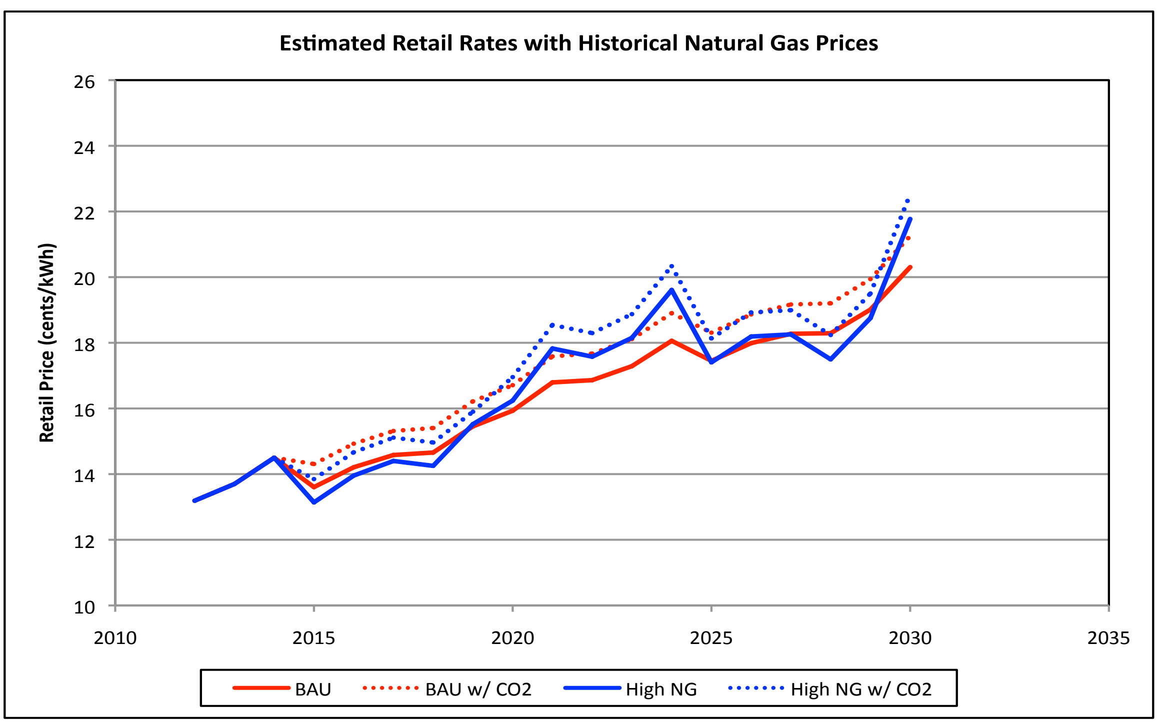


Table 1: Comparison of Retail Rates, BAU vs. Fuel switching (cents/kWh)

Estimated Retail Rates Using Stable NG Prices				
Year	2015	2020	2025	2030
BAU	14.50	16.43	18.70	$21.41
% Above BAU	0.00%	2.06%	3.54%	6.27%
30% RPS	14.50	16.76	19.36	$22.75
% Above BAU	0.00%	0.81%	2.96%	8.70%
Fuel Switch	14.50	16.56	19.25	$23.27
Estimated Retail Rates Using Historical NG Prices				
BAU	14.50	16.49	$18.66	21.59
% Above BAU	0.00%	2.05%	3.59%	6.17%
30% RPS	14.50	16.83	$19.33	22.92
% Above BAU	0.00%	1.70%	1.36%	11.85%
Fuel Switch	14.50	16.78	$18.92	24.15

When historical natural gas prices are applied in years 2015-2030, the fuel-switching scenario illustrates the risk of rapid price swings for utilities and ratepayers. For example, retail electricity prices rise from 15.7 cents/kWh in 2018 to 19.1 cents/kWh in 2024 when gas prices rise above $9/mcf. Under the BAU scenario, prices rise from 15.6 cents/kWh in 2018 to 18.4 cents/kWh in 2024 and 21.4 cents/kWh by 2030. When a price on CO_2 is included, retail rates under the fuel switching rise above 23.9 cents/kWh in 2030 compared to 23.3 cents/kWh under the BAU scenario.

Figure 4: Retail Rates, BAU vs. Fuel Switching with Historical NG Prices



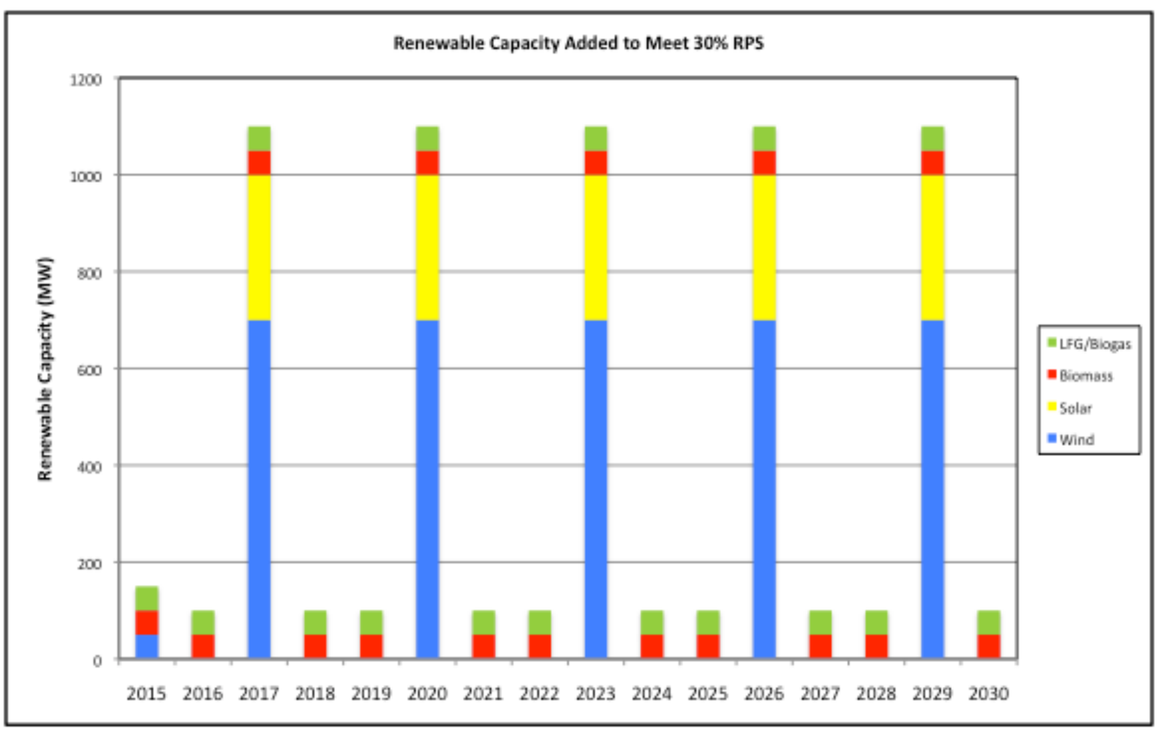
Monthly Electricity Bills

Under these forecasted retail prices, an average Wisconsin home using 500kWh/month would spend $60/month in 2012 under the BAU scenario, rising to $69/month in 2020 and $97/month in 2030. Under the fuel-switching scenario, monthly bills rise to $68 in 2020 and $91 by 2030. While this is not a large difference, the fuel-switching scenario exposes utilities and ratepayers to significant uncertainty by tying electricity supplies to historically volatile natural gas supplies. Building a diverse energy portfolio with higher levels of renewable to offset coal-fired generation can help reduce vulnerability to unexpected fuel price shocks.

Aggressive Renewable Portfolio Standard (30% by 2030)

Under this scenario, Wisconsin shifts away from coal with a mixture of natural gas and aggressive renewable energy deployment. Coal generation was again decreased by 4.5% annually, and a mixture of renewables is added to Wisconsin's generation mix form 2015-2030 as shown in Table 2. MyPower does not allow the user to incrementally reduce generation, so coal-fired units were retired in the year they reached 50 years of age to approximate the coal reductions tested in the spreadsheet model. The MyPower scenario resulted in the closure of the 1,235MW Pleasant Prairie, 1,163MW Weston, 1,240MW Oak Creek, 345MW Genoa, 441MW Pulliam and 136MW Alma plants between 2015-2028.

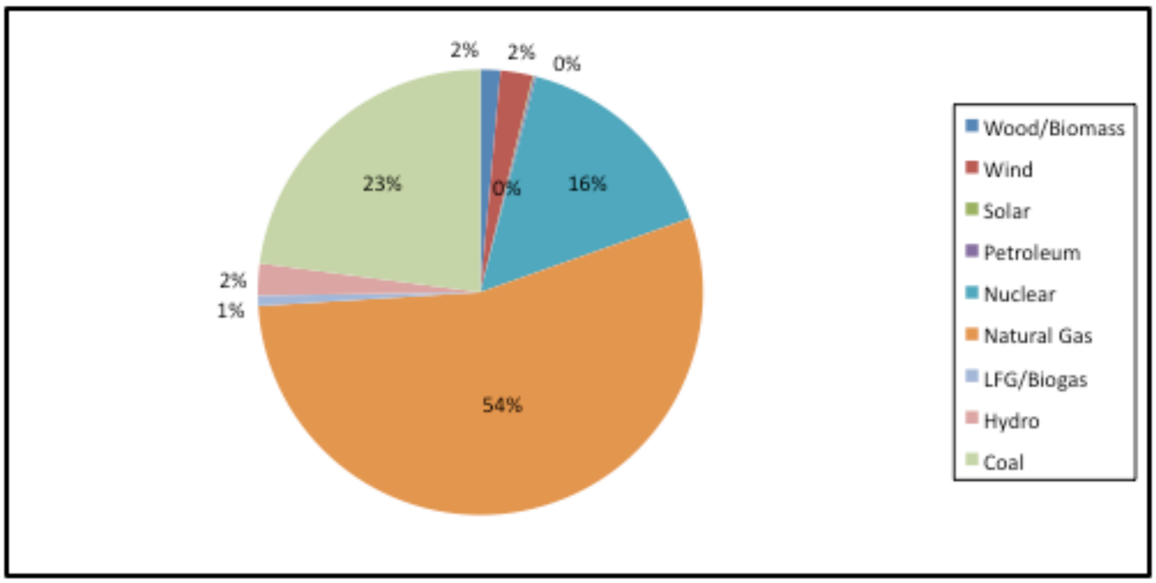
Figure 4: Additional Renewable Capacity built from 2015-2030



Achieving 420MW of solar by 2020 is not an unrealistic goal. Minnesota's 1.5% solar carve-out will stimulate an estimated 400-450MW of solar growth by 2020.[5] In fact, the City of Madison alone has enough rooftop area to support an estimated 730MW of solar PV.[6] For wind, the Department of Energy produced estimates showing that Wisconsin can support over 103,000MW of high quality wind capacity (defined as sites that can achieve a 30% capacity factor at an 80 meter hub height).[7] The 2030 goal of 4,436MW represents only 4.3% of DOE's total estimated potential. Biomass capacity could be new, or converting existing coal-fired boilers.

For biogas, farms with 2,500-4,000 head of cattle produced an average of 440MWh/year meaning Wisconsin would need about 15,000 farms (total WI dairy farms source) to install biogas generators to meet the 2030 goal.[8] Put another way, 10% of Wisconsin 11,490 dairy farms would need to install a 1MW genset to meet the 2030 goal. At the end of 2012, Germany had 7,500 biogas generators with a combined capacity of 3,200MW that produced 23 million MWh of electricity.[9] This translates into an average system size of about 425kW and a capacity factor of 82%. Germany's current biogas capacity is more than three times larger than the proposed 980MW by 2030 and Wisconsin is only about half the size of Germany.[10]

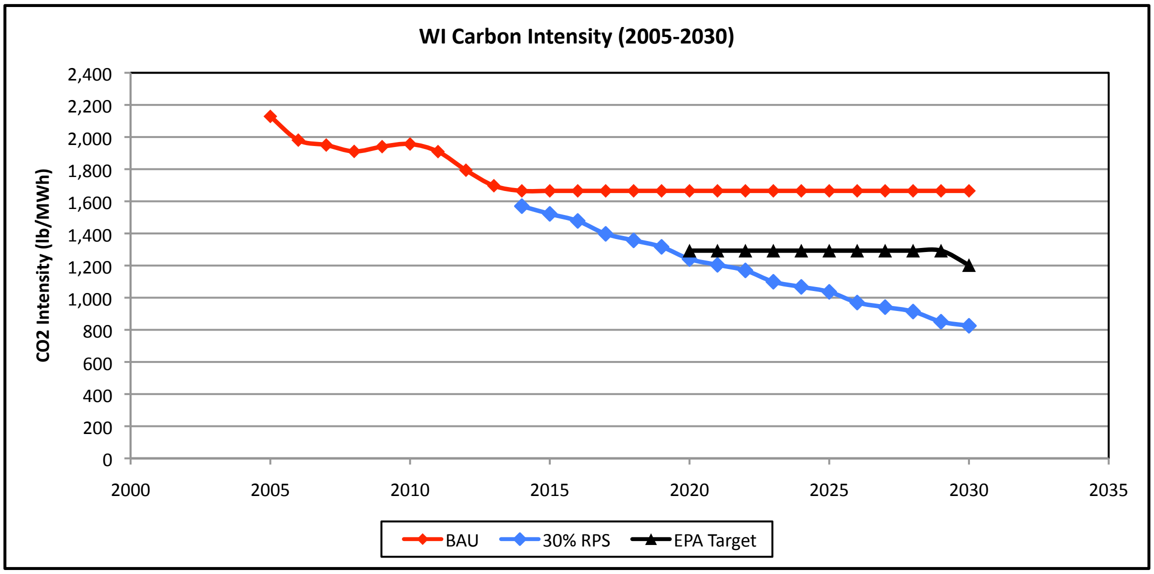
Figure 5: Generation Mix in 2030 Under 30% RPS Scenario



5 Farrell, "Minnesota's New Solar Energy Standard." ILSR, 28 May 2013 (link)
6 Kaldunski (2014). "An Economic Analysis of Microgrids." WIDRC, 10 October 2014 (link).
7 DOE Office of Energy Efficiency & Renewable energy (2010). Wind Resource Potential (link).
8 *The Biogas Opportunity in Wisconsin.* Wisconsin Bioenergy Initiative, 2011 (link).
9 German Energy Agency (2011). Renewables Made in Germany (link).
10 Germany has one digester per 18.3 square miles versus one digester per 2,114 square miles in WI.

Wisconsin's CO_2 emissions decline dramatically, with an average carbon intensity of 1,049 lb/MWh from 2020-2029 and 825 lb/MWh in 2030. In overall mass terms, this represents a 58% reduction from 2005 levels, and a 33% reduction from 2012 levels. Achieving the 30% RPS would raise total generation from $3.13 billion under the BAU scenario ($46.91/MWh) to $3.81 billion ($57.12/MWh).

Figure 6: Wisconsin's CO_2 Intensity under 30% RPS Scenario



Retail electricity prices still outpace the BAU scenario, but the margins are smaller and prices converge by 2030. In 2020, the 30% RPS scenario results in prices of 16.8 cents/kWh compared to 16.4 cents/kWh under the BAU. Adding a $10/ton price on CO_2 raises the prices to 19.7 cents/kWh and 18.4 cents/kWh, respectively. By 2030, the 30% RPS scenario results in retail rates of 22.7 cents/kWh compared to 21.1 cents/kWh for the BAU scenario. When a price on CO_2 is included, the 30% RPS scenario results in retail rates less than 2 cents above the BAU scenario (25.1 cents/kWh versus 23.3 cents/kWh).

The 30% RPS scenario also mitigates the risk of natural gas price volatility. The 30% RPS scenario produces lower retail rates in 2026-2030 compared to the fuel-switching scenario when no CO_2 cost is considered. When a $10/ton compliance cost is added, the 30% RPS results in lower retail electricity prices from 2023-2030. The results of the MyPower simulations also show that the 30% RPS scenario is more cost-effective by 2030. The value of renewables as a hedge against price volatility is shown in Figure 9 where the fuel-switching scenario is compared to the 30% RPS scenario.

Figure 7: Retail Electricity Rates, BAU vs. 30% RPS Scenario

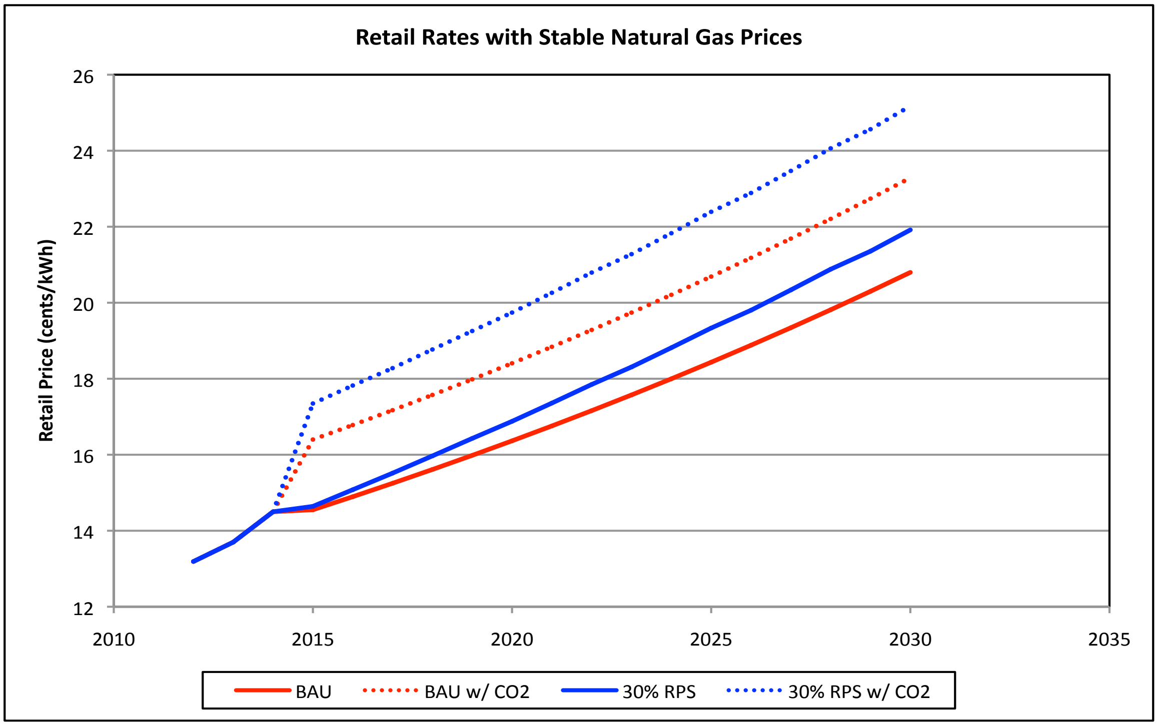


Figure 8: Retail Rates, BAU vs. 30% RPS Scenario

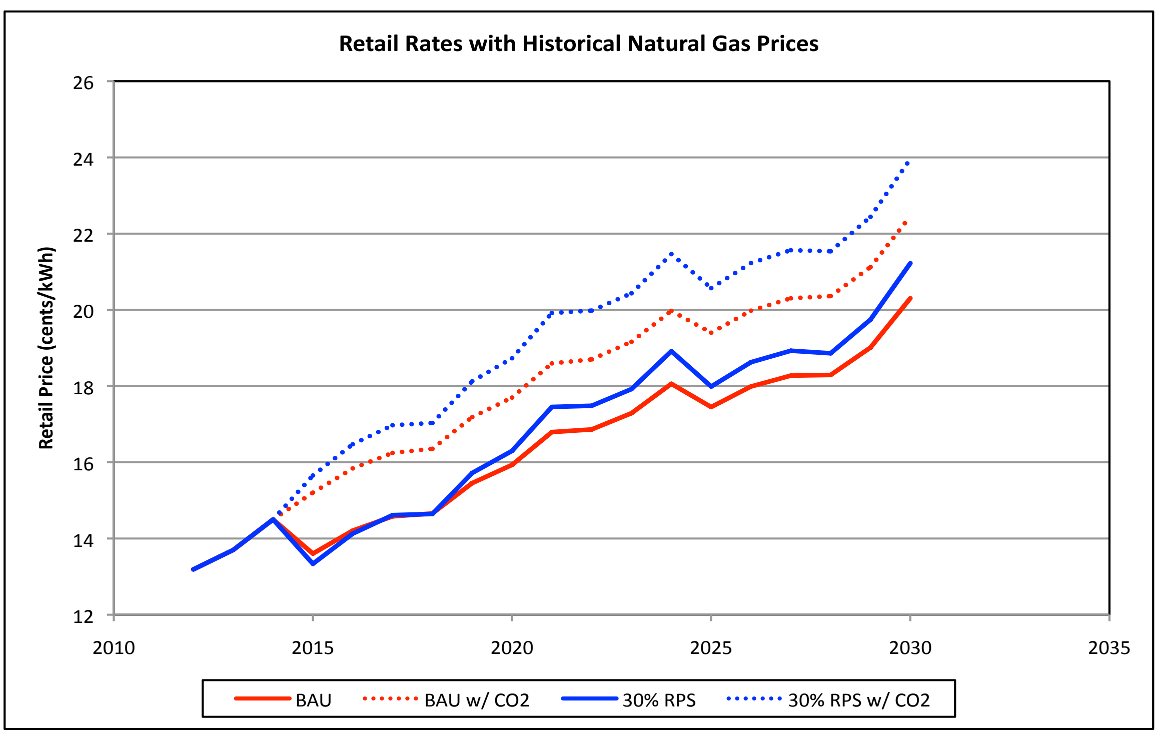


Table 3: Retail Rates, BAU vs. 30% RPS Scenario (cents/kWh)

Year	2020	2025	2030
BAU	16.37	18.43	20.80
BAU w/ CO_2	18.41	20.69	23.29
BAU Historical NG Prices	15.93	17.45	20.30
BAU Historical Prices & CO_2	17.70	19.40	22.46
30% RPS	16.88	19.33	21.92
30% RPS w/ CO_2	19.74	22.39	25.18
30% RPS, Historical NG Prices	16.30	17.99	21.22
30% RPS, Historical NG & CO_2	18.73	20.57	23.96

While the 30% RPS scenario is not cost competitive against the BAU scenario, it is a more economical option than the fuel-switching scenario. Retail prices under the 30% RPS scenario are lower than the fuel-switching scenario from 2026-2030 when no CO_2 price is added, and from 2023-2030 when a $10/ton CO_2 is included. Under the volatile gas price scenario, the hedging value of renewables is clearly illustrated. For example, in years 2024 and 2030, retail prices under the 30% RPS scenario are more than 2 cents/kWh lower than the fuel-switching scenario.

Figure 9: Retail Electricity Rates, Fuel Switching vs. 30% RPS Scenario

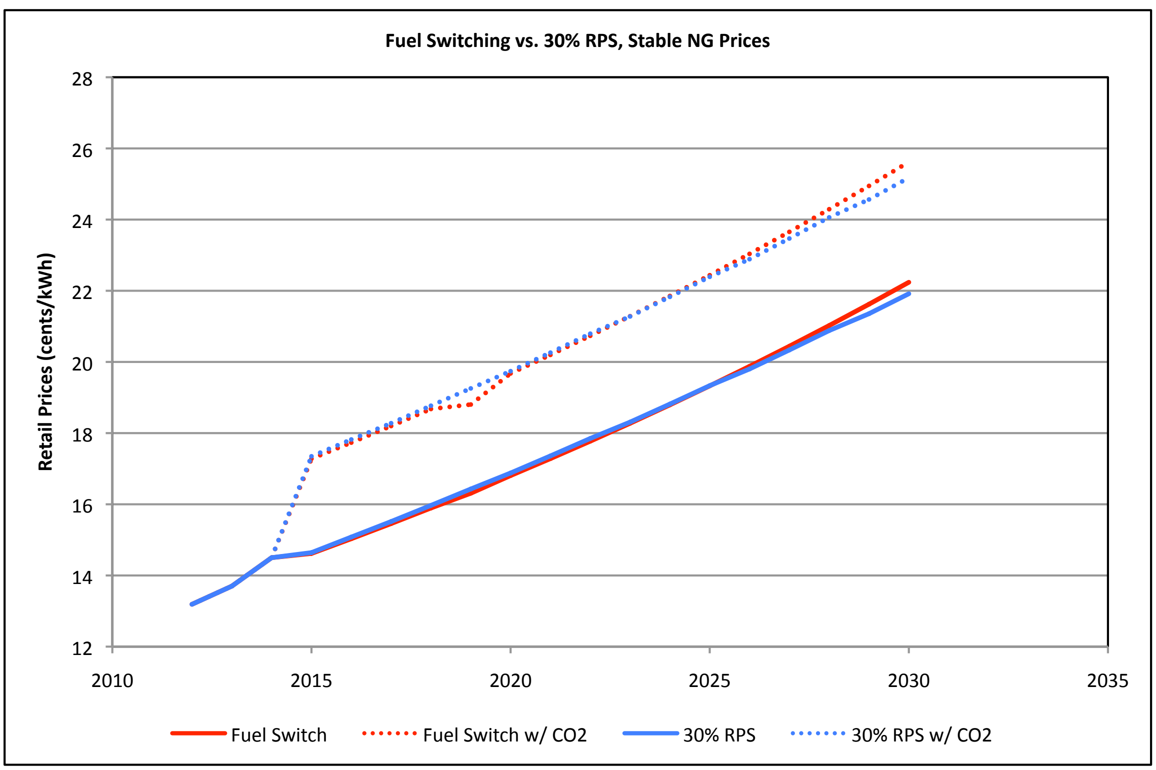


Figure 10: Retail Electricity Rates, Fuel Switching vs. 30% RPS Scenario

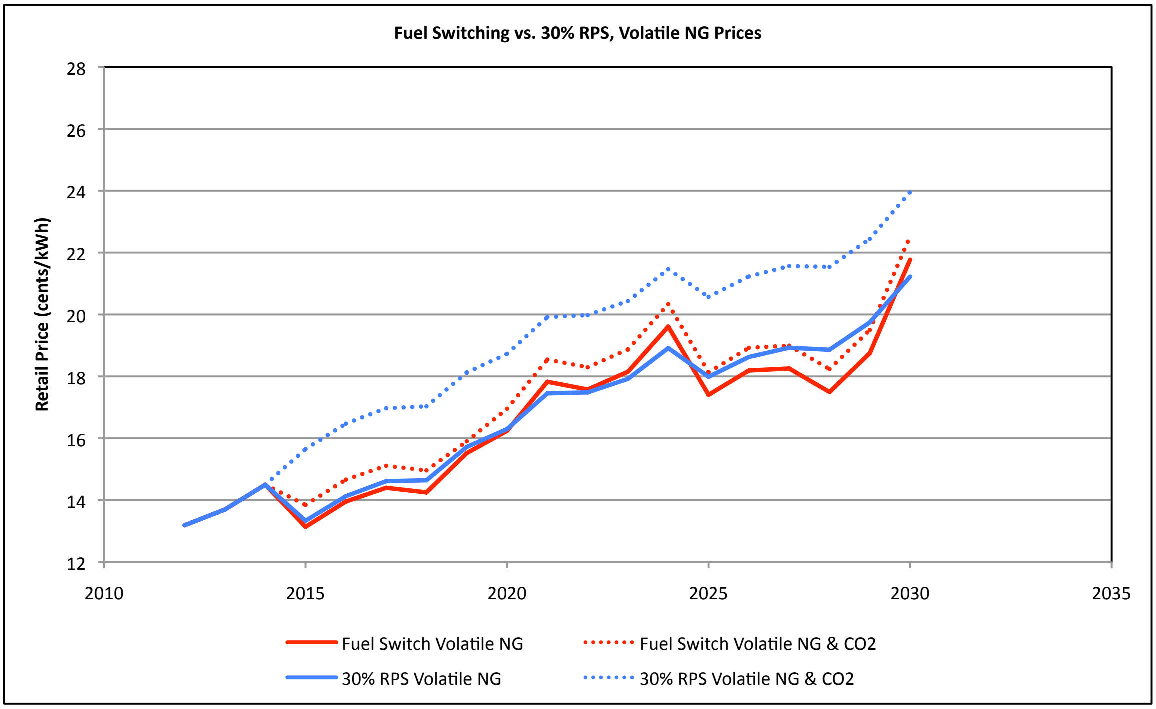


Table 4: Retail Rates, Fuel Switching vs. 30% RPS Scenario (cents/kWh)

Year	**2020**	**2025**	**2030**
Fuel Switch	16.81	19.33	22.24
Fuel Switch CO_2	19.68	22.44	25.62
Fuel Switch Volatile NG	16.24	17.40	21.77
Fuel Switch Volatile NG & CO_2	16.95	18.13	22.52
30% RPS	16.88	19.33	21.92
30% RPS w/ CO_2	19.74	22.39	25.18
30% RPS Volatile NG	16.30	17.99	21.22
30% RPS Volatile NG & CO_2	18.73	20.57	23.96

In 2030, the forecasted rates in Table 4 translate into monthly bills of $93/month under the fuel-switching scenario compared to $95/month under the 30% RPS scenario. Monthly bills under the 30% RPS never rise more than $2 above the fuel switching scenario until 2026 when they dip below the fuel switching scenario. Figure 10 also shows the vale of renewables as a hedge against fuel price volatility. The 30% RPS produces lower costs and associated retail rates from 2021-2024 when historical natural gas prices are applied to the simulation. The 30% RPS scenario is the lower cost compliance option under the Clean Power Plan.

The benefits of using renewables as a hedge against fuel price volatility can be achieved without sacrificing reliability, or incurring claw back from so-called renewable “integration” costs. In March 2014, the PJM grid operator issued a report that revealed it could handle up to 30% renewable penetration on it’s system “without any significant reliability issues.”[11] NREL researchers found that fossil fuel cycling under high renewable penetration only added $0.2-$1.28/MWh in marginal operating costs.[12]

Conclusion

This preliminary analysis shows that Wisconsin can meet EPA’s CO_2 reduction targets by pursuing two compliance options, a 30% by 2030 RPS, or a statewide shift to displace coal with increased dispatch of existing natural gas units. While the 30% RPS will require significant construction of new renewable generation, it is cost-competitive with the natural gas fuel switching alternative by 2030 (though actual costs could vary widely depending on many variables that were not tested in this initial analysis). The 30% RPS scenario will also result in highly diversified generation mix that will insulate Wisconsin’s utilities and electric ratepayers against volatile fuel prices and potential CO_2 compliance costs.

Other Midwestern states are already pursuing aggressive RPS policies (Minnesota’s 25% by 2025 RPS and Iowa already obtains 25% of its annual electricity from wind) and Wisconsin is quickly falling behind. Renewable energy companies are abandoning the state despite it’s history of leadership in power electronics and manufacturing because of weak, or obtrusive policies and utility initiatives. The Wisconsin DNR and PSC can set the state on a path toward a clean, reliable and cost-effective energy future by implementing sound policies and regulations that incentivize renewable energy development and collaboration between end-use customers and utilities alike.

Table 5: Marginal Generation Cost Comparison w/out CO_2 Costs

Marginal Generation Costs ($/MWh) from MyPower				
Year	2015	2020	2025	2030
BAU (Stable Prices)	$32.83	$36.60	$41.25	$46.91
BAU (Historical NG Prices)	$32.48	$36.88	$40.58	$47.89
30% RPS (Stable Prices)	$33.06	$39.90	$46.90	$57.12
30% RPS (Historical NG Prices)	$32.70	$40.16	$46.28	$58.00
Fuel Switch (Stable Prices)	$33.03	$38.01	$45.99	$60.95
Fuel Switch (Historical Prices)	$32.11	$39.05	$42.29	$66.52

[11] Executive Summary of Renewable Integration Study for PJM, 28 February 2014 (link).

[12] *Western Wind & Solar Integration Study.* NREL, September 2013 (link).

Technical Appendix

The results of MyPower simulations were used to calculate estimated retail rates using the following steps. Total generation (MWh), fuel consumption by fuel type (mmBtu), emissions (tons) are grouped into a chronological table. The total cost of generation is determined by multiplying the price of each fuel type ($/mmBtu) by the total fuel consumption for each fuel type, or by applying a $/MWh factor in the case of renewables (wind/solar/hydro) that do not consume fuel. The total cost in each year is then divided by the forecast demand, which is based on 2012 demand increasing at 0.25% annually. The growth in annual demand is based on average growth rates observed from 2007-2012 shown in the table below:

Year	Generation	% Change	Retail Sales	% Change
1990	47,768,856		49,198,028	
1991	49,356,736	3.32%	51,032,208	3.73%
1992	48,893,398	-0.94%	50,925,090	-0.21%
1993	50,238,552	2.75%	53,156,402	4.38%
1994	52,358,955	4.22%	55,411,611	4.24%
1995	53,923,131	2.99%	57,966,904	4.61%
1996	54,417,739	0.92%	58,743,628	1.34%
1997	51,414,009	-5.52%	60,094,002	2.30%
1998	56,447,431	9.79%	62,061,221	3.27%
1999	58,538,851	3.71%	63,547,448	2.39%
2000	59,644,419	1.89%	65,146,487	2.52%
2001	58,763,433	-1.48%	65,218,293	0.11%
2002	58,431,438	-0.56%	66,999,296	2.73%
2003	60,122,425	2.89%	67,241,494	0.36%
2004	60,444,933	0.54%	67,975,709	1.09%
2005	61,824,664	2.28%	70,335,683	3.47%
2006	61,639,843	-0.30%	69,820,749	-0.73%
2007	**63,390,630**	**2.84%**	**71,301,300**	**2.12%**
2008	**63,479,555**	**0.14%**	**70,121,827**	**-1.65%**
2009	**59,959,060**	**-5.55%**	**66,286,439**	**-5.47%**
2010	**64,314,067**	**7.26%**	**68,752,417**	**3.72%**
2011	**63,289,344**	**-1.59%**	**68,611,622**	**-0.20%**
2012	**63,742,910**	**0.72%**	**68,820,090**	**0.30%**

Over the 2007-2012 time period, in-state generation has grown by 0.64% annually, while retail sales (which is used as a measure of annual demand) declined by an average 0.20% annually. An average of these two figures results in a composite growth rate of 0.22% annually. A summary of generation and consumption growth over 20, 10 and 5-year time periods is included on the following page.

Wisconsin Electric Demand Growth Summary Statistics				
1990-2012 Growth	15,974,054	33.44%	19,622,062	39.88%
1990-2012 Growth Rate	726,093	1.38%	891,912	1.56%
2002-2012 Growth	5,311,472	9.09%	1,820,794	2.72%
2002-2012 Growth Rate	482,861	0.79%	165,527	0.52%
2007-2012 Growth	352,280	0.56%	-2,481,210	-3.48%
2007-2012 Growth Rate	58,713	0.64%	-413,535	-0.20%
Source: EIA State Electricity Profile				

After the total cost of annual generation was calculated, it is divided by annual demand to produce a marginal cost of electricity generation and supply ($/MWh). Using MyPower to model costs based on stable natural gas prices, the marginal generation cost under the BAU scenario was found to increase from $33/MWh to $47/MWh from 2015-2030. Under the 30% RPS scenario, marginal generation costs rise from $33-$57/MWh, and $33-$61/MWh under the fuel switching scenario. Results from the MyPower simulations are shown in the table below.

Marginal Generation Costs ($/MWh) from MyPower				
Year	2015	2020	2025	2030
BAU (Stable Prices)	$32.83	$36.60	$41.25	$46.91
BAU (Historical NG Prices)	$32.48	$36.88	$40.58	$47.89
30% RPS (Stable Prices)	$33.06	$39.90	$46.90	$57.12
30% RPS (Historical NG Prices)	$32.70	$40.16	$46.28	$58.00
Fuel Switch (Stable Prices)	$33.03	$38.01	$45.99	$60.95
Fuel Switch (Historical Prices)	$32.11	$39.05	$42.29	$66.52

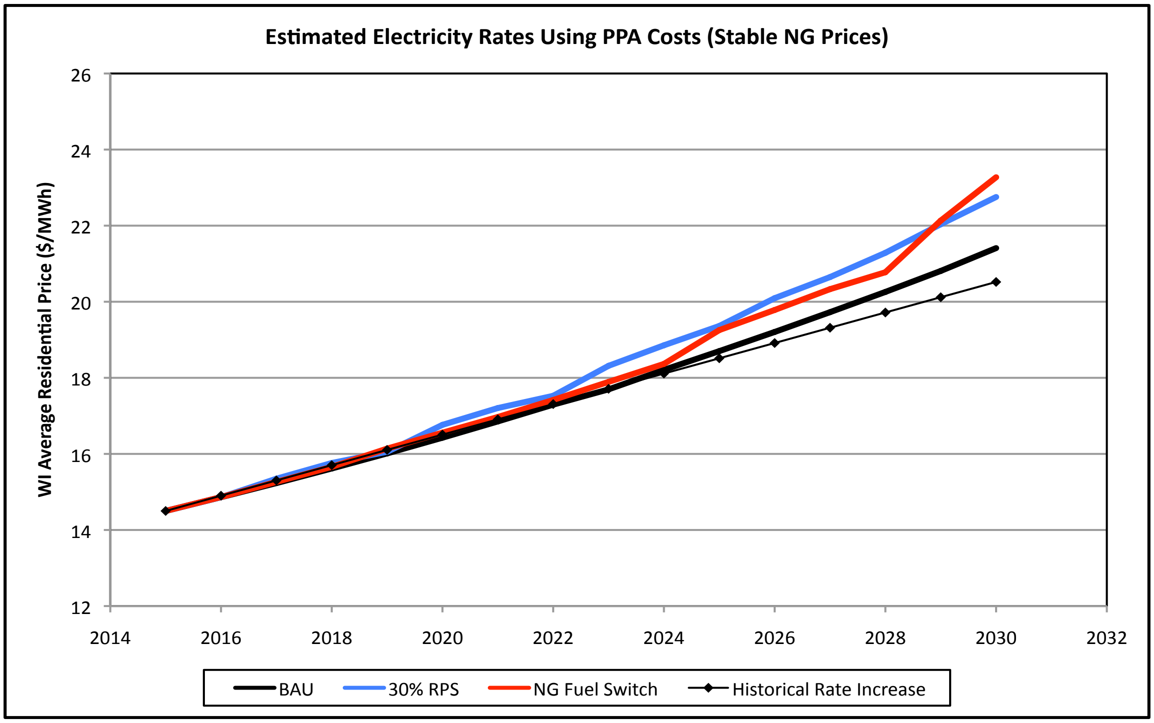
The estimated retail electricity prices are determined by these marginal generation costs. The retail rates are estimated by adding or subtracting the year-to-year change in generation costs to the previous year's retail rate. The retail rate in 2015 (the first year of the simulation) is set at $145/MWh (14.5 cents/kWh), based on the most recent monthly statistics for Wisconsin's statewide average residential prices provided by EIA. The resulting retail rate is then multiplied by a 2% annual growth factor to account for inflation and historical rate increases in Wisconsin. From 1990-2012, residential rates in Wisconsin have risen by 3.21% annually, 4.79% from 2002-2012 and 3.87% annually from 2007-2012.

Summary of WI Rate Increases		
1990-2012 Growth	6.56	98.94%
1990-2012 Growth Rate	0.30	3.21%
2002-2012 Growth	5.01	61.25%
2002-2012 Growth Rate	0.46	4.79%
2007-2012 Growth	2.32	21.34%
2007-2012 Growth Rate	0.39	3.87%
1997-2012 CAGR	6.02	4.15%

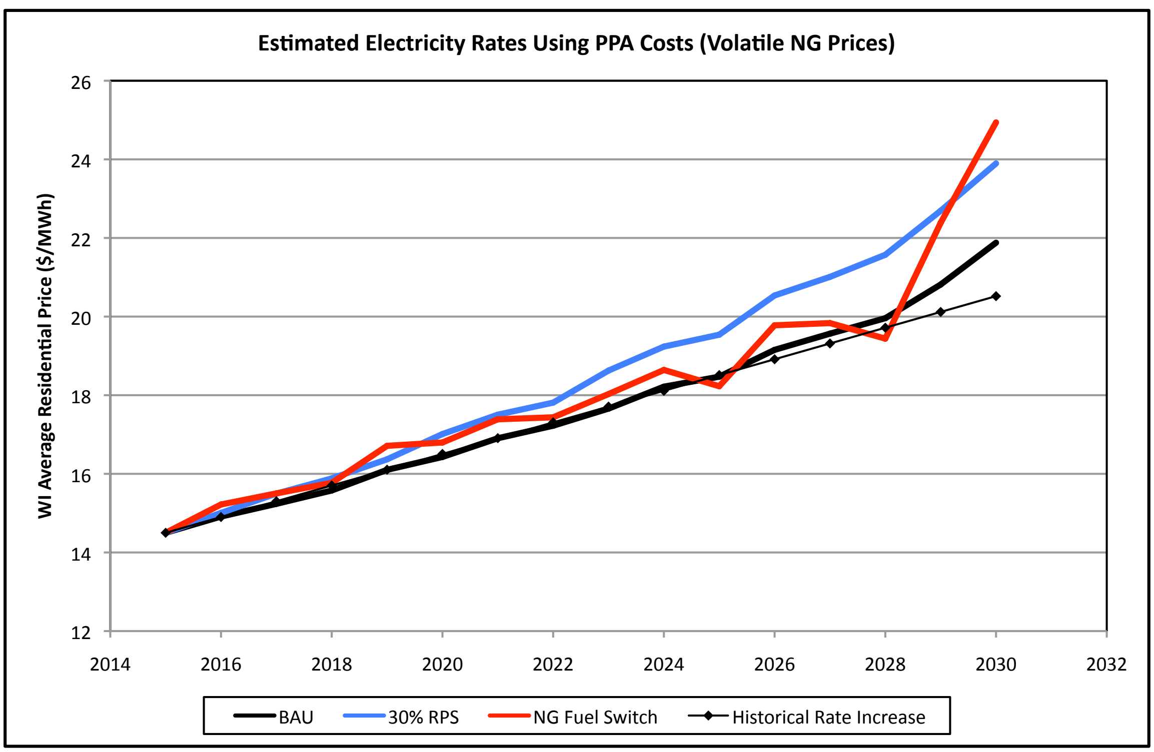
Year	Residential Avg	% Change
1990	6.63	
1991	6.73	1.51%
1992	6.91	2.67%
1993	7.03	1.74%
1994	7.08	0.71%
1995	6.97	-1.55%
1996	6.88	-1.29%
1997	6.88	0.00%
1998	7.17	4.22%
1999	7.31	1.95%
2000	7.53	3.01%
2001	7.90	4.91%
2002	8.18	3.54%
2003	8.67	5.99%
2004	9.07	4.61%
2005	9.66	6.50%
2006	10.51	8.80%
2007	10.87	3.43%
2008	11.51	5.89%
2009	11.94	3.74%
2010	12.65	5.95%
2011	13.02	2.92%
2012	13.19	1.31%

Estimated retail electricity prices from the MyPower simulations based on stable natural gas prices are shown in the table below, and the figures on the following page. The 2015 natural gas price is set at $5/mmBtu and increases at 2% annually. The same annual increase is applied to coal and oil-fired generation.

Estimated Retail Rates Using Stable NG Prices				
Year	2015	2020	2025	2030
BAU	14.50	16.43	18.70	21.41
% Above BAU	0.00%	2.06%	3.54%	6.27%
30% RPS	14.50	16.76	19.36	22.75
% Above BAU	0.00%	0.81%	2.96%	8.70%
Fuel Switch	14.50	16.56	19.25	23.27
Estimated Retail Rates Using Stable NG Prices				
Year	2015	2020	2025	2030
BAU	14.50	16.49	$18.66	21.59
% Above BAU	0.00%	2.05%	3.59%	6.17%
30% RPS	14.50	16.83	$19.33	22.92
% Above BAU	0.00%	1.70%	1.36%	11.85%
Fuel Switch	14.50	16.78	$18.92	24.15

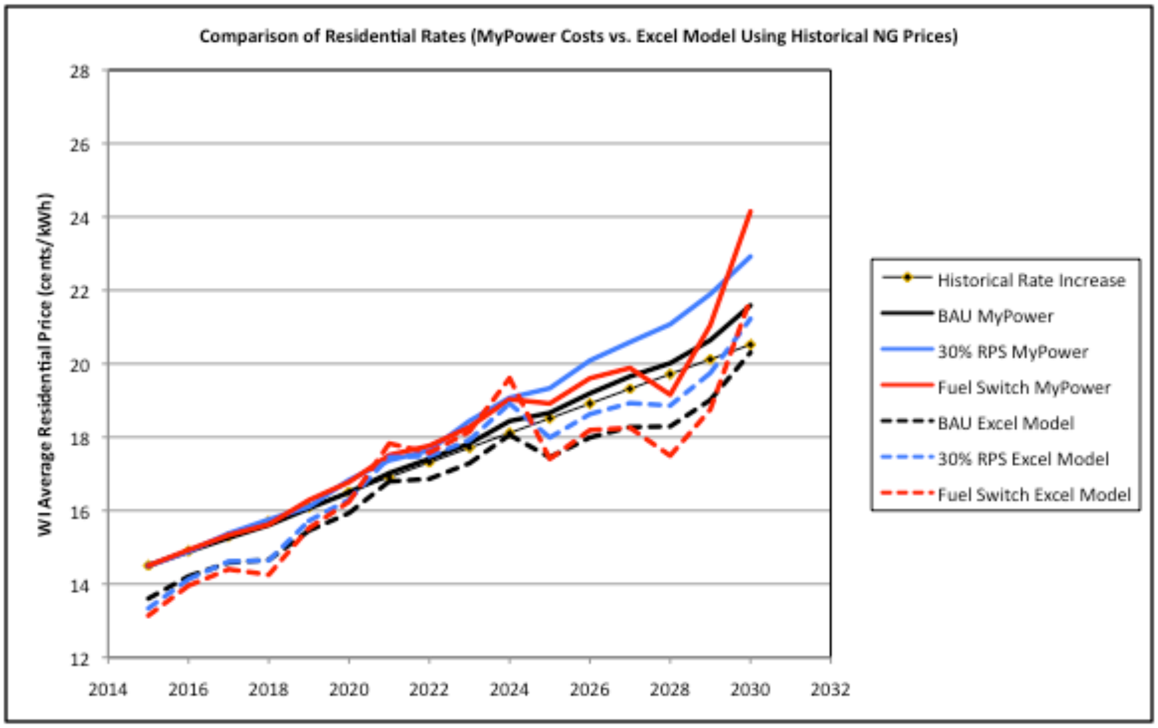


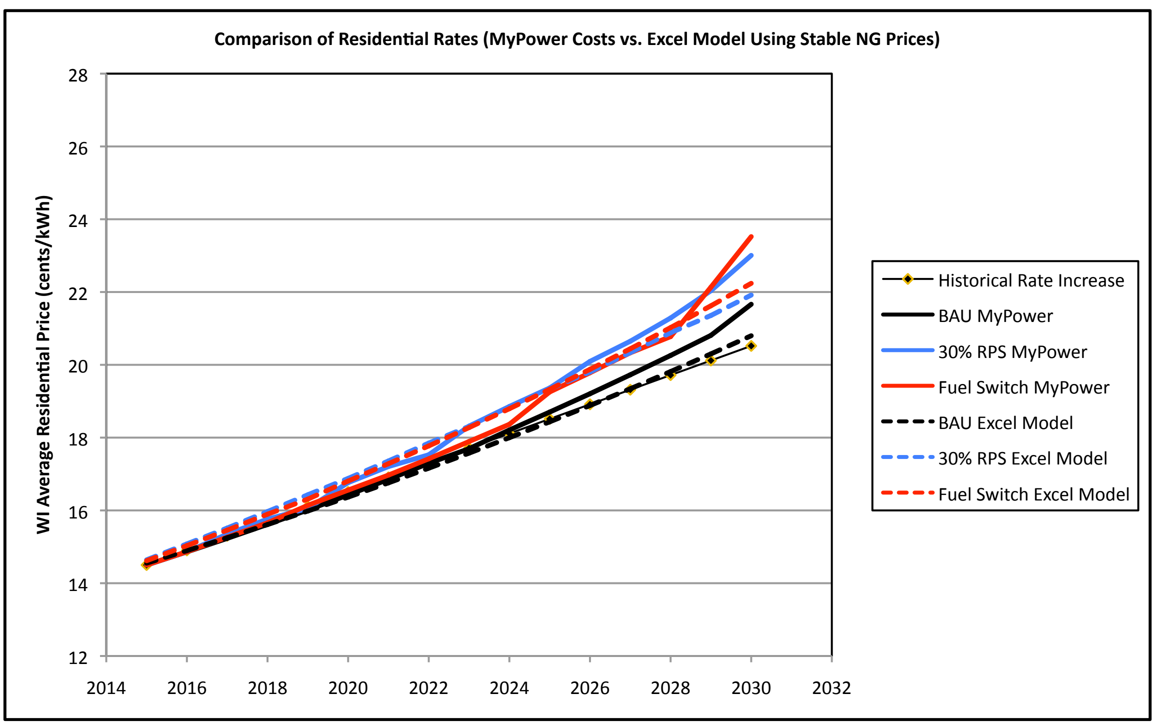
Estimated Electricity Rates Using PPA Costs (Stable NG Prices)
WI Average Residential Price ($/MWh)
26
24
22
20
18
16
14
12
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
BAU
30% RPS
NG Fuel Switch
Historical Rate Increase



Estimated Electricity Rates Using PPA Costs (Volatile NG Prices)
WI Average Residential Price ($/MWh)
26
24
22
20
18
16
14
12
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
BAU
30% RPS
NG Fuel Switch
Historical Rate Increase

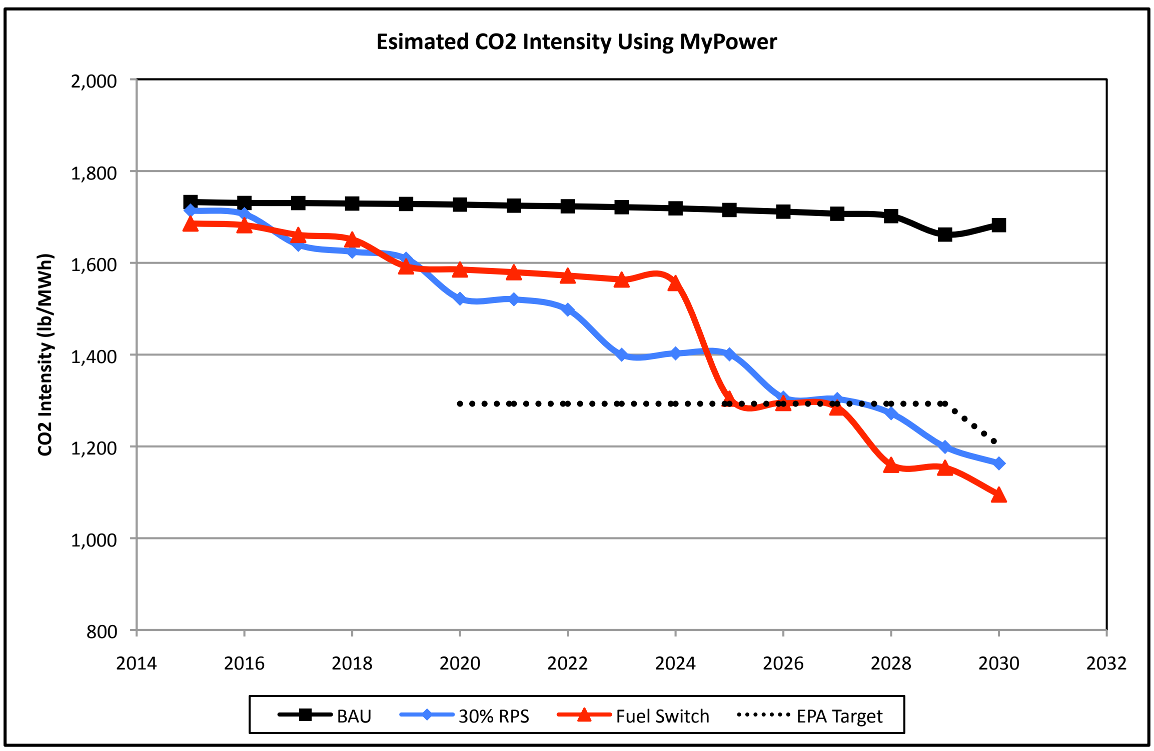
Using historical prices to estimate fuel price volatility shows that the fuel switching scenario can result in higher costs than the 30% RPS scenario. These results match the results produced using the Spreadsheet model. A comparison between the MyPower results and Spreadsheet model results is shown on the following page.





The two models produce very similar results when natural gas prices increase at a constant rate, but the Spreadsheet model produces slightly lower rate estimates when natural gas prices are adjusted for historical volatility. The overall trend is consistent between the two models, volatile natural gas prices can cause the fuel switching scenario to incur higher costs than the 30% RPS scenario.

The MyPower simulation also produces annual emissions totals for CO_2, SO_2 and NO_x. The fuel switching scenario did not add any new renewable capacity (consistent with the Spreadsheet model), but coal-fired generation cannot be gradually reduced in MyPower. Therefore, coal-fired units were retired in the year that they reached 50 years of age in the MyPower simulation to roughly align with the transition from coal to gas-fired generation in the Spreadsheet model. For the 30% RPS scenario, the Spreadsheet model also reduced coal-fired generation by 1.5% annually. No coal-fired units were retired in the MyPower version of the 30% RPS simulation. This results in higher carbon intensity scores for the 30% RPS in the MyPower simulation compared to the Spreadsheet model simulation as shown in the figure below.



While the 30% RPS can result in lower rate increases than the fuel switching scenario, it does carry a higher marginal cost of carbon abatement, as shown in the table on the following page. The table compares the cumulative costs above the BAU scenario from 2015-2030 and the resulting CO_2 reductions each scenario produces. Abatement costs under the 30% RPS scenario are slightly higher than the costs under the fuel switch scenario (roughly \$35/ton compared to \$30/ton).

Scenario in MyPower	30% RPS	Fuel Switch
Cost Above BAU	$4,506,909,564	$3,526,803,798
CO_2 Reductions	126,070,564	114,263,370
Average Abatement Cost ($/ton)	$35.75	$30.87

The abatement cost estimates produced using the Spreadsheet model are reversed, with the 30% RPS emerging as the more cost-effective strategy. This is likely caused by the larger CO_2 reductions stemming from the 1.5% annual reduction in coal-fired generation that was not modeled in the MyPower simulation. The larger amount of reductions spread across a similar investment in renewable energy lowers the average CO_2 abatement cost.

The total additional investment required to achieve the 30% RPS in the Spreadsheet model is significantly higher than the MyPower estimates, while cumulative CO_2 reductions are higher by about 107 million tons. The MyPower cost estimates for the fuel switching scenario are less than half those forecasted in the Spreadsheet model, but the Spreadsheet model also predicts 30 million tons of additional CO_2 reductions. These conflicting results show that reducing coal-fired generation in conjunction with expanding renewables can achieve deeper CO_2 cuts (shown in the Spreadsheet model) and lead to lower abatement costs. The spreadsheet model predicts marginal fuel/generation costs that are nearly twice that predicted in MyPower, but the year-over-year increases are very similar. Future calibration of the spreadsheet model will be done to reconcile these differences.

Scenario in Excel Model	30% RPS	Fuel Switch
Cost Above BAU	$9,182,597,452	$8,493,671,690
CO_2 Reductions	233,382,495	144,790,940
Abatement Cost ($/ton)	$39.35	$58.66

A sharp increase in natural gas consumption could result in much higher methane emissions from leaks in the transmission and distribution network, which could increase total CO_2 equivalent (CO_2e) emissions. Methane is about 25 times as potent as CO_2 (1 ton of methane is equivalent to 25 tons of CO_2), so these leaks represent a major concern for the viability of CO_2 reductions from fuel switching.

Using EPA's estimate of a 2% methane leakage rate, the fuel switching scenario would result in 14.7z million tons of additional CO_2e above the BAU scenario. Recent studies have questioned the validity of EPA's estimates and suggested that much higher leakage rates are actually occurring. Using a 10% leakage rate adds 92.5 million tons of CO_2e under the fuel switching scenario compared to 18.7 million tons under the 30% RPS scenario. This pushes the 2030 carbon intensity from 1,095 lb/MWh to 1,605 lb/MWh under the fuel switching scenario, and increases the marginal abatement cost from $30/ton to $84/ton. The 30% RPS scenario sees a much smaller increase in carbon intensity, from 1,199 lb/MWh to 1,212 lb/MWh and marginal abatement cost of $35/ton. Clearly, the 30% RPS is a more effective mitigation strategy when fugitive methane emissions are considered.

CO_2e Emissions with a 2% Methane Leakage Rate			
Scenario	**BAU**	**30% RPS**	**Fuel Switch**
CO_2 Emissions (tons)	768,374,795	642,322,812	654,334,710
2030 CO_2 lb/MWh	1,682	1,199	1,095
Fugitive Methane CO_2e (tons)	4,094,658	3,748,588	18,503,843
Total CO_2e (tons)	772,469,453	646,071,400	672,838,553
2030 CO2e lb/MWh	1,700	1,212	1,197
CO_2e Abatement ($/ton)	$-	$35.66	$35.42

CO2e Emissions with a 10% Methane Leakage Rate			
Scenario	**BAU**	**30% RPS**	**Fuel Switch**
CO_2 Emissions (tons)	768,374,795	642,322,812	654,334,710
2030 CO_2 lb/MWh	1,682	1,199	1,095
Fugitive Methane CO_2e (tons)	20,473,289	18,742,941	92,519,216
Total CO_2e (tons)	788,848,084	661,065,753	746,853,926
2030 CO_2e lb/MWh	1,772	1,267	1,605
CO_2e Abatement ($/ton)	-	$35.28	$84.03

Fugitive Methane Calculations

The calculations used to derive the amount of CO_2e attributed to natural gas combustion in the electric power sector is shown in the tables below.[13]

2011 Methane Emissions (million tons)	**6.89**
Methane Emissions Attributed to Electricity Generation	2.14
Methane Content of Natural Gas (%)	85%
2011 Natural Gas Production (trillion cubic feet)	24.25
2011 Electric Sector Consumption (trillion cubic feet)	7.53
2011 Methane Equivalent (trilling cubic feet)	20.61
Methane Density (lb/cf)	0.0447
Total Methane Equivalent (million tons)	418.8
Leakage Rate (%)	1.65%
Fugitive Methane (tons/mcf consumed)	0.0003
CO_2e (tons/mcf)	0.0071
CO_2e (million tons)	**172.3**

[13] Hauschfather and Muller (2014). "EPA Report Reveals Significantly Lower Methane Leakage from Natural Gas." Berkeley Earth Institute (link).

Fugitive Methane Calculations (Power Plant Based)

NGCC Heat Rate (mmBtu/MWh)	7
Natural Gas Heat Content (mmBtu/mcf)	1.025
Natural Gas Consumption (mcf/MWh)	5.975
Fugitive Methane Emissions (tons/MWh)	0.0017
CO_2e (tons/MWh)	**0.0424**
CO_2e (lb/MWh)	**84.9**
Annual Generation (MWh)	1,000,000
CO_2e (tons/year)	42,441
NG Consumed by Power Plants (trillion cubic feet)	7.39
Natural Gas Generation (GWh)	1,225,894
Natural Gas Consumption (mcf/MWh)	6.03
Fugitive Methane (tons/MWh)	0.0017
Fugitive Methane (tons/mcf)	0.0003
CO_2e (tons/MWh)	**0.0436**
CO_2e (lb/MWh)	**87.3**

Cost of Renewables Used in MyPower/Spreadsheet Model

Cost of Biomass for Electricity Generation		
Study/Source	Low Generation Cost ($/MWh)	High Generation Cost ($/MWh)
Extension Study (2013)	$47.00	$50.00
City of Escanaba (Biomass)	$94.00	$144.00
WI PSC (Biomass)	$123.00	$123.00
Average	$88.00	$105.67
Cost of Wind		
City of Escanaba (Wind0	$55.00	$65.00
AWEA (2012)	$31.00	$84.00
Xcel Energy	$29.00	
UCS Comments to MI PSC	$52.00	$65.00
WI PSC (Wind)	$89.00	$89.00
Average	$50.25	$75.75
Cost of Solar		
WI PSC (Solar)	$229.00	$229.00
GTM Research	$86.00	$86.00
UCS Comments to MI PSC	$58.00	$100.00
Crossroads Energy (NC 2013)	$73.00	$93.00
LBNL (2013)	$50.00	$150.00
Average	$66.75	$131.60
Cost of Biogas	$91.00	$157.00
WI PSC (2012 RPS Report)	$74.00	$77.00

The cost of renewables ($/MWh) in both the Spreadsheet model and MyPower simulation were based on a survey of power purchase agreement (PPA) Prices for a variety of renewable energy projects. The Wisconsin PSC's most recent RPS compliance report also stated that the average cost of renewables purchased to meet compliance with the program in 2012 was $77/MWh. This price was used to cover wind/solar/biogas in the MyPower simulation, while individual prices for each type of renewable were used in the Spreadsheet model. The fuel costs for coal, natural gas, and fuel oil are based on EIA's most recent monthly data and are summarized in the table below.

Fossil Fuel Type	**$/mmBtu**	**$/ton,mcf,bbl**	Source: EIA
Coal (short tons)	$3.00	$34.68	Source: We Energies
Natural Gas (mcf)	$5.00	$5.13	Source: EIA
Fuel Oil (barrels)	$15.00	$94.31	Source: EIA

EPA Projections

EPA sets a goal for Wisconsin to produce 7,476 MWh of renewable electricity by 2030, or 12% of the state's 2012 demand. The results of IPM modeling forecast that Wisconsin will need to generate 3,977MWh from wind, 1,212 MWh from biomass, and 2,287 MWh from hydro to meet the 2030 carbon reduction goal.[14] Under the 30% RPS scenario, Wisconsin would generate 11.5 million MWh from wind, 2.1 million MWh from solar, 4.9 million MWh from biomass and 6.8 million MWh from biogas. Coal falls from 51% to 24% of the state's total generating mix (15.2 million MWh), while natural gas holds steady at 22% (13.8 million MWh).

Limitations of this Analysis

The data used in both the spreadsheet and MyPower models is derived from publicly available sources that do not reflect the many layers of complexities that affect each utility's power generation decisions. The cost estimates produced from this analysis should not be considered as final results. The purpose of this first cut analysis is to explore large scale trends in statewide energy costs and emissions profiles under the fuel switching and 30% RPS compliance strategies. Both the spreadsheet model and MyPower are limited by data availability and assumptions that may not reflect actual operating conditions in local markets. Future wok will be performed to determine deficiencies in both the spreadsheet and MyPower models to produce a complimentary set of tools that policy makers can use to compare emissions reduction strategies.

[14] EPA (2014), Clean Power Plan Proposed Rule Technical Support Documents (link).

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