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Cost-Effectively Achieving Carbon Goals in Minnesota: Renewable Standards vs. Technology-Neutral Policies

A scenario-based analysis of electric-sector impacts through 2050

Technical Brief — *Preliminary Insights from EPRI Minnesota High Renewable Standards Project*

KEY INSIGHTS

- A technology-neutral carbon reduction policy (e.g., a CO_2 target) could achieve the same level of CO_2 emissions reduction in Minnesota at lower cost than a high renewable electricity standard of 60% by 2030 and 95% by 2050, saving $2.7 billion in total electric sector costs between 2015–2050.
- A high renewable standard would likely require significant investments in new transmission between Minnesota and neighboring states, more so than a comparable CO_2 target.
- Operating under a CO_2 target, Minnesota's generation fleet could provide the state with higher electric sector revenues than under a comparable high renewable standard.
- A CO_2 target supports approximately the same amount of new Minnesota wind, and more in-state generation investment overall, than a high renewable standard achieving the same level of carbon reduction.

PROJECT OVERVIEW

Background

Between 2007 and 2017, Minnesota witnessed a more than 300 percent increase in renewable energy-based generation. Indeed, renewable energy deployment has proceeded at such a rapid pace in the region overall that by 2018—using a combination of wind, solar, biomass, and hydropower—Minnesota had already achieved its 2025 renewable electricity standard goal of 25% of retail sales; and is on-track to meet its standard of 1.5% solar by the end of 2020. [1]

Renewable energy installations continue in Minnesota's electric power sector as part of the state's overall 'clean energy transition' and to meet the state's economy-wide greenhouse gas (GHG) emissions reduction goal of 80% by 2050. However, while renewable energy has played an important role in reducing electric power sector GHG (e.g., carbon dioxide) emissions, other sources of low-carbon electricity also play a role in decarbonization—including in other sectors of the economy[2]—and as part of a diverse portfolio of resources, may achieve the same carbon reduction goals at a lower total cost.

Analysis Objectives

The purpose of this analysis is to investigate and compare the cost-effectiveness of renewable energy standards and technology-neutral policies for reducing carbon dioxide (CO_2) emissions from Minnesota's electric power sector between 2015 and 2050.

Using EPRI's in-house electric sector capacity expansion and dispatch model, US-REGEN (described below), the analysis quantifies the cost-differences between the policy approaches, and examines the key drivers of those differences, including (1) how generation capacity and transmission capacity investments in the state and across the region are expected to change over time; (2) the flow of electricity and renewable energy certificates (RECs) in-and-out of Minnesota; and (3) the revenues generated by in-state electric sector resources.

Scenarios

To explore the impacts of future electric sector high renewable standards against those of direct carbon emissions targets, this analysis compared modeling results from three distinct scenarios or "future states of the world":

1. A "business-as-usual" Reference scenario, defined as a future with Minnesota's existing ('on-the-books') Renewable Energy Standard (RES), no state or federal CO_2 policy, and the rest of the U.S. under existing policies.
2. A High Renewable Standard (HRS) scenario, defined as a future where Minnesota adopts a new 60% by 2030 and 95% by 2050 RES. This standard is equivalent to 85-90% (2030) and 90-95% (2050) below Minnesota's electric sector 2005 CO_2 emissions. This scenario assumes no state or federal CO_2 policy, and the rest of the U.S. maintains existing policies.

1 Minnesota Commerce Department (2018). Minnesota Renewable Energy Update, November 2018, https://mn.gov/commerce-stat/pdfs/2017-renewable-energy-update.pdf
2 EPRI (2018). *U.S. National Electrification Assessment*, April 2018, https://www.epri.com/#/pages/product/3002013582/

3. A CO_2 Target scenario, defined as a future with no existing or new state RES, but instead an electric-sector CO_2 emissions mandate equivalent to the CO_2 emissions trajectory from the HRS scenario (Figure 1). This scenario allows for an 'apples-to-apples' comparison of the impacts from two different policy approaches to achieving the same level of CO_2 reductions from Minnesota's electric sector. In this future, the rest of the U.S. still maintains all existing policies.

EPRI's US-REGEN Model[3]

US-REGEN is a state-of-the-art capacity planning and dispatch model of the electric sector that provides an intertemporal optimization of generation and transmission capacity investments over a decadal time horizon, given assumptions about technology availability and costs, policies, and market environments. The model is built to capture the unique characteristics of variable renewable energy and specifically, the correlations between hourly time-series variables like load, and wind and solar resources, across regions.

For this study, US-REGEN aggregates the contiguous U.S. into fifteen regions, representing Minnesota and its four neighboring Midwestern states as individual regions to allow for additional granularity in the results in this region of focus (Figure 2). Using this spatial aggregation, the model explicitly optimizes building and producing electricity with in-state generation resources versus building and producing electricity with neighboring out-of-state generation resources to meet Minnesota's electric demands and policy goals over time. In considering the least-cost way to meet these objectives, the model simultaneously considers the net costs of new transmission capacity between Minnesota and its neighboring states to support electricity trade with neighbors, as well as the cost of purchasing and selling RECs to comply with renewable electricity standards.

Modeling Inputs and Assumptions

General Assumptions

- Electricity demand is calculated using EPRI's detailed bottom-up End-Use Model, as used in EPRI's 2018 National Electrification Assessment.[4]
- Hourly regional renewable output and resource potentials are based on analysis and data by EPRI and NASA's MERRA-2 dataset.
- Electricity trade in a given hour is constrained by net transfer capacities of transmission between model regions, which can change over time as new transmission investments are made.
- Fuel prices for this study are based on the U.S. Energy Information Administration's Annual Energy Outlook 2018 'High Oil and Gas Recovery' path, which has natural gas remaining around \$3/MMBtu (in real dollar terms) through 2050.
- Technology costs are based on research from EPRI Program 178a and EPRI's Generation Technology Options Report.[5] Modeled Minnesota wind and solar PV capital costs in 2050 are \$750/kW and \$400/kW (2018\$), respectively.[6]

Key Policy Assumptions

- Electricity from all in-state renewable resources, including hydropower and international hydropower imports, contribute to meeting Minnesota's renewable electricity standards.
- Out-of-state REC purchases provide another option for meeting Minnesota's RES; for the purposes of this modeling, EPRI assumes Minnesota purchases only RECs from adjacent neighbors (i.e., North Dakota, South Dakota, Iowa, and Wisconsin), and requires that Minnesota also purchase the electricity generation that produced the REC.

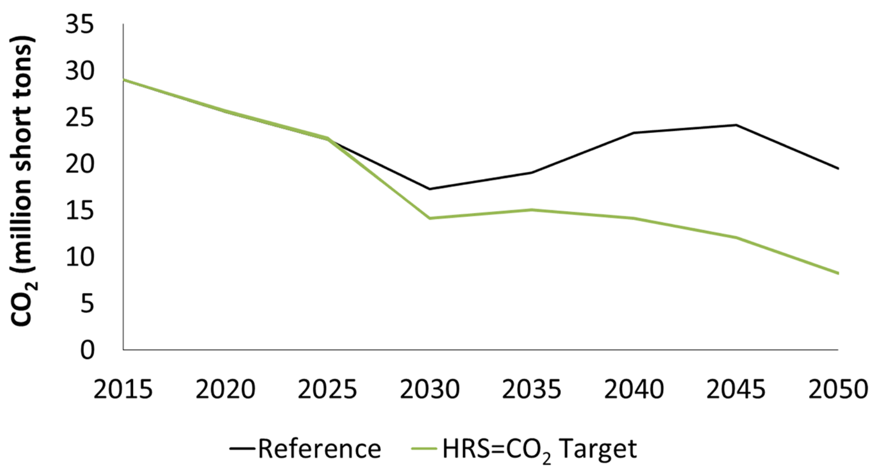

Figure 1 – Minnesota Electric Sector CO_2 Emissions by Scenario

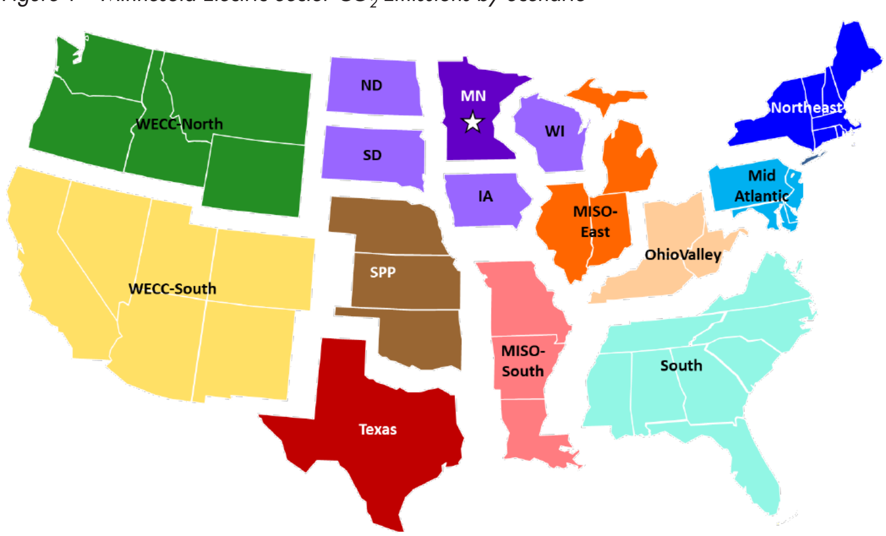

Figure 2 – US-REGEN Minnesota HRS Analysis Regions

3 EPRI (2018). *US-REGEN Model Documentation*, April 2018, https://www.epri.com/#/pages/product/3002010956/

4 EPRI (2018). *U.S. National Electrification Assessment*, April 2018, https://www.epri.com/#/pages/product/3002013582/

5 EPRI (2013). *Program on Technology Innovation: Integrated Generation Technology Options 2012*, February 2013, https://www.epri.com/#/pages/product/1026656/

6 Wind technology capital costs follow a slightly lower trajectory (10% lower than EPRI's default costs) to reflect local expectations about new wind investments in Minnesota. The model also uses an additional cost for interconnection of renewable technologies.

- No national CO_2 policy is assumed in any scenario. However, other key existing policies, including RGGI, AB32, ITC/PTC, CAA 111(b) NSPS for fossil-fired units, and other state RPS programs are represented in all scenarios.

ANALYSIS RESULTS

Of the scenarios studied and given the assumptions described in the preceding section, this analysis finds that an explicit, technology-neutral carbon reduction policy (i.e., a CO_2 target) could significantly lower costs for reducing carbon emissions in Minnesota's electric sector, as compared to a high renewable standard that achieves an equivalent level of CO_2 emissions reduction (Figure 1). Specifically, for a RES of 60% by 2030 and 95% by 2050, a CO_2 policy that restricts CO_2 emissions to the same levels the RES achieves incurs $2.7 billion less in cumulative net electric sector costs over the study horizon (i.e., a 3-5% cost reduction). The same CO_2 target also provides overall cost savings over the Reference scenario that includes Minnesota's existing RES. Cost savings are lower (approximately $300 million), but this suggests Minnesota's existing RES also has room for efficiency improvement when viewed as a CO_2 emissions reduction policy.

Differences between in-state generation and neighboring out-of-state generation used to meet Minnesota electric demand, drive most of the cost disparity between the three policy scenarios. When meeting a stringent HRS, Minnesota could spend significantly more importing renewable electricity generated in neighboring states (Figure 3, light blue bar), as well as the RECs associated with these imports (Figure 3, pink bar). Figure 4 shows the breakdown of these resources used to meet demand in each scenario in 2045[7], and the shift towards importing more power from the Dakotas (light green and purple bars) and Wisconsin (light pink bar) under the HRS.[8]

The operation of existing assets, such as nuclear, is likely extended under a technology-neutral CO_2 target also—Minnesota's nuclear units operate through 2045 under this scenario (Figure 4, dark gray bar).

A second related insight is that a CO_2 target could incentivize more in-state investments than an HRS. Figures 3 and 4 show that net power imports are lower under the CO_2 Target scenario than under the HRS scenario—aligned with net power imports under the Reference scenario. Simultaneously, in-state capacity investments are higher than under an HRS (Figure 3, dark blue bar and Figure 5). Figure 5 also shows the breakdown of cumulative

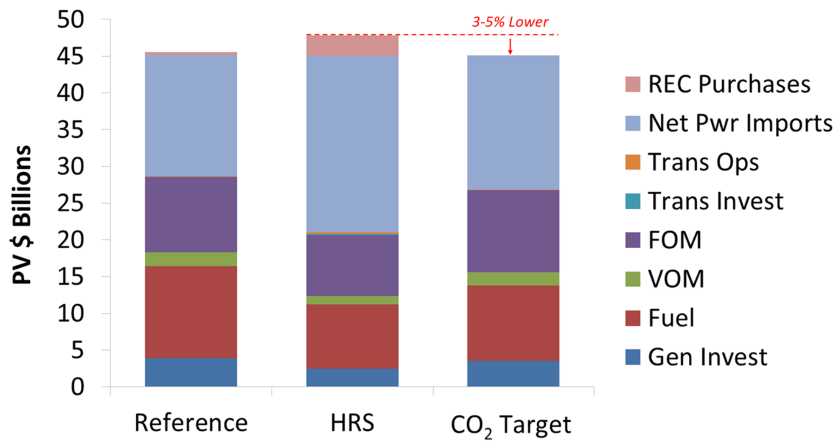

Figure 3 – Minnesota Electric Sector Total Costs (2015–2050)

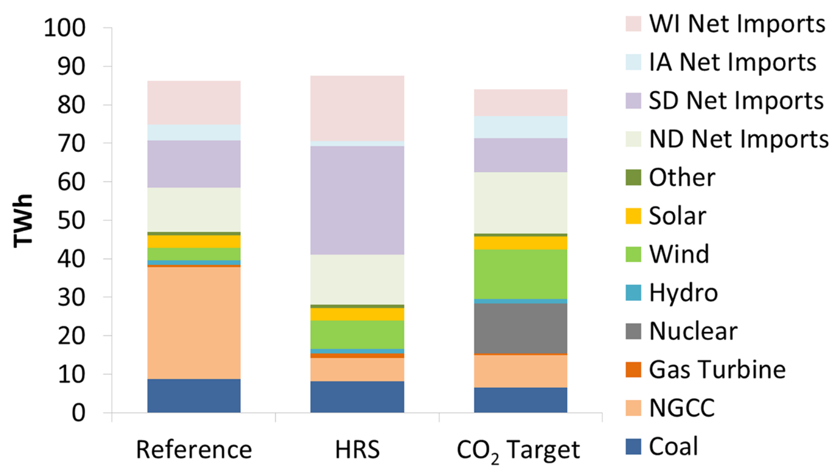

Figure 4 – In-State vs. Out-of-State Generation Resources Used to Meet Minnesota Demand (2045)

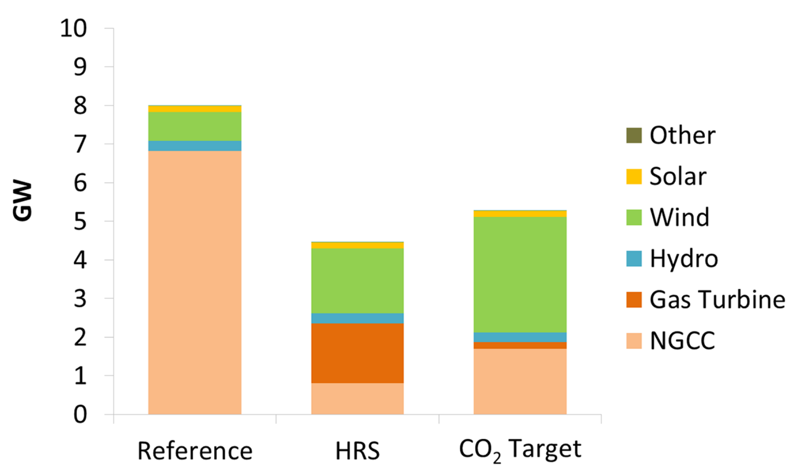

Figure 5 – Minnesota Cumulative Generation Capacity Additions (2045)

7 Snapshots from 2045 are used to show electricity generation (Figure 4) and capacity results (Figure 5) by scenario, as this allows time for the system to have responded to the policies, but avoids potentially over-inferring from 2050 'end-of-horizon' effects, including the model's retirement of nuclear units.

8 US-REGEN's application of NASA's MERRA weather data and EPRI's technology cost data results in slightly more favorable wind resource profiles and technology costs in South Dakota than North Dakota, leading to the model's preference for developing new South Dakota generation capacity under an HRS.

capacity additions to Minnesota's generation fleet in 2045. While Minnesota adds the most capacity on a GW basis in the Reference scenario, Minnesota develops more in-state generation resources under the CO_2 target than under an HRS. This trend continues through 2050 even as cumulative wind investments even out between the three scenarios (3.0, 2.8, and 3.0 GW under the Reference, HRS, and CO_2 Target, respectively), and additional natural gas units are built under the CO_2 target to replace nuclear retirements in 2050.

Model results also show that an additional 3 GW (approximately two or three new CapX-sized 345-kV transmission line projects) of new Minnesota-connected interstate transmission capacity would be needed to meet the HRS scenario at least-cost, compared to only 0.2 GW to meet the CO_2 Target scenario and zero MW under the Reference scenario. However, the costs associated with this new transmission capacity, when compared to the costs associated with new generation capacity, electricity generation, and electricity market purchases, are a small fraction of the overall costs.

A third related insight is that Minnesota's generation fleet could provide the state with higher electric sector revenues under a CO_2 target than under an HRS (Figure 6). When revenues from REC, energy, and capacity sales are combined, the CO_2 target provides Minnesota with approximately 30% more revenue than the HRS. Additionally, most of this additional revenue opportunity from new resources comes from in-state wind energy sales (Figure 6, bright green bar).

The combination of these system dynamics—fewer net electricity imports; a lack of required associated REC purchases (no renewables policy); fewer inter-regional transmission capacity investments; and more energy market revenue potential from new in-state wind and existing resources (e.g., nuclear)—illustrate how the CO_2 target examined here is the most cost-effective at reducing carbon from Minnesota's electric sector, of the three scenarios considered. Conversely, significant net electricity imports (and associated REC purchases) and fewer opportunities to earn energy market revenue from Minnesota's generation fleet are the main drivers behind the HRS scenario's comparably higher costs.[9]

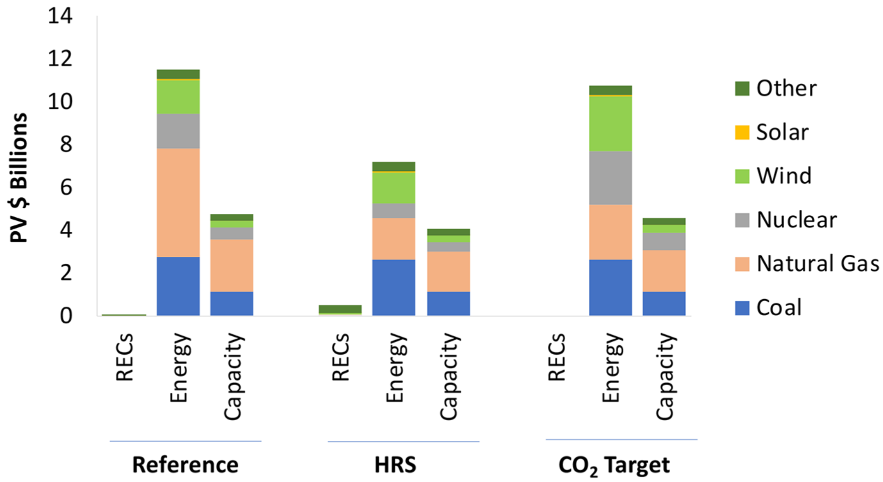

Figure 6 – Minnesota Electric Sector Revenue Sources (2015-2050)

Limitations of this Analysis

This analysis highlights the costs and cost-drivers of potential policy approaches for reducing carbon emissions in Minnesota's electric sector. As with any analysis, quantitative results (e.g., $2.7 billion savings using CO_2 targets in MN), are based on specific input assumptions and model structure (described above). However, qualitative results (e.g., a technology-neutral policy approach offers a lower cost alternative to an HRS) would likely remain the same.

In addition, it is important to note that as abstractions of the complex, real-world economic and energy systems they seek to represent, models like US-REGEN may contain inherent approximation errors, issues with data quality, and/or incomplete system dynamics. For example, as with other capacity expansion models looking at a decadal timeframe, the version of US-REGEN used in this study does not capture ancillary service dynamics such as black start, frequency regulation, or voltage support, nor does it capture operational constraints such as unit minimum loads and ramping constraints. However, high renewable penetration levels, like those observed in this analysis, will likely have unique economic and technical challenges; it will be important to complement these scenarios using power system models with more spatial and temporal granularity to understand these additional challenges.

Finally, it is important to keep in mind that analyses using models like US-REGEN are not intended to be viewed as a prediction of an outcome or cluster of outcomes. Insights are derived from running a variety of scenarios and comparing the results, as was the approach used in this study.

FUTURE RESEARCH

The three scenarios examined in this study represent the first phase of EPRI's year-long Minnesota High Renewable Standards project. As such, the results in this study are preliminary, but raise important questions about the efficiency of approaches to decarbonizing Minnesota's electric sector. These results develop a foundation for further analysis that will investigate cost-effective approaches to decarbonizing the electric sector.

Based on the importance of electricity trade, REC trade, and in-state vs. out-of-state new capacity investments (e.g., wind and natural gas units) illustrated in the first phase, potential future scenarios include examining impacts of:

- Electricity trade restrictions;
- Transmission investment and delivery costs;
- RES flexibility provisions (e.g., REC trade formulations);
- Alternate natural gas prices; and
- Alternate renewable technology costs.

9 Actual costs may be higher as US-REGEN does not currently consider siting and political considerations in making new transmission investment decisions. Additionally, US-REGEN does not model costs associated with intra-regional transmission and distribution.

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