SMARTransmission℠

Phase 2 Report
Strategic Midwest Area Renewable Transmission (SMARTransmission) Study

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1 Background

The Strategic Midwest Area Renewable Transmission Study, or SMARTransmission, investigated transmission overlays to facilitate the development of Midwest wind energy generation and enable its delivery to consumers within the study area. Transmission needs were analyzed from a regional perspective over a study area that encompasses some of the nation's best wind resources, including parts of North Dakota, South Dakota, Iowa, Indiana, Ohio, Illinois, Michigan, Minnesota, Nebraska, Missouri and Wisconsin. The study's primary goal is to develop a transmission plan that ensures reliable service, is environmentally friendly, and supports state and national energy policies. SMARTransmission focuses 20 years into the future and incorporates information from existing studies, as appropriate.

SMARTransmission was sponsored by Electric Transmission America (ETA) – a transmission joint venture between subsidiaries of American Electric Power and MidAmerican Energy Holdings Company, American Transmission Company, Exelon Corporation, NorthWestern Energy, MidAmerican Energy Company – a subsidiary of MidAmerican Energy Holdings Company – and Xcel Energy. The sponsor group engaged Quanta Technology LLC (Quanta) to evaluate extra-high voltage (EHV) Alternatives and provide recommendations for new transmission development.

2 Executive Summary

SMARTransmission was completed in two phases. The transmission alternatives chosen for economic analysis during Phase 2 were determined during Phase 1 of the study. The Phase 1 report can be found on the SMARTransmission website[1]. Phase 1 results indicated that three Alternatives - one combination 345kV and 765kV (Alternative 2), one 765kV (Alternative 5), and one 765 kV with an additional HVDC line replacing a 765 kV line (Alternative 5A) warranted additional assessment. Since Alternative 5A was substantially similar to Alternative 5, the consensus among the sponsors was that the economic results for Alternatives 5 and 5A would also be similar. As a result, economic analysis in Phase 2 was completed only on Alternatives 2 and 5. Alternative 2, Alternative 5, and Alternative 5A are shown in Figure 2-1, Figure 2-2, and Figure 2-3.

[1] Phase 1 report is available at http://www.smartstudy.biz/.

Figure 2-1 Conceptual EHV Transmission Overlay Alternative 2

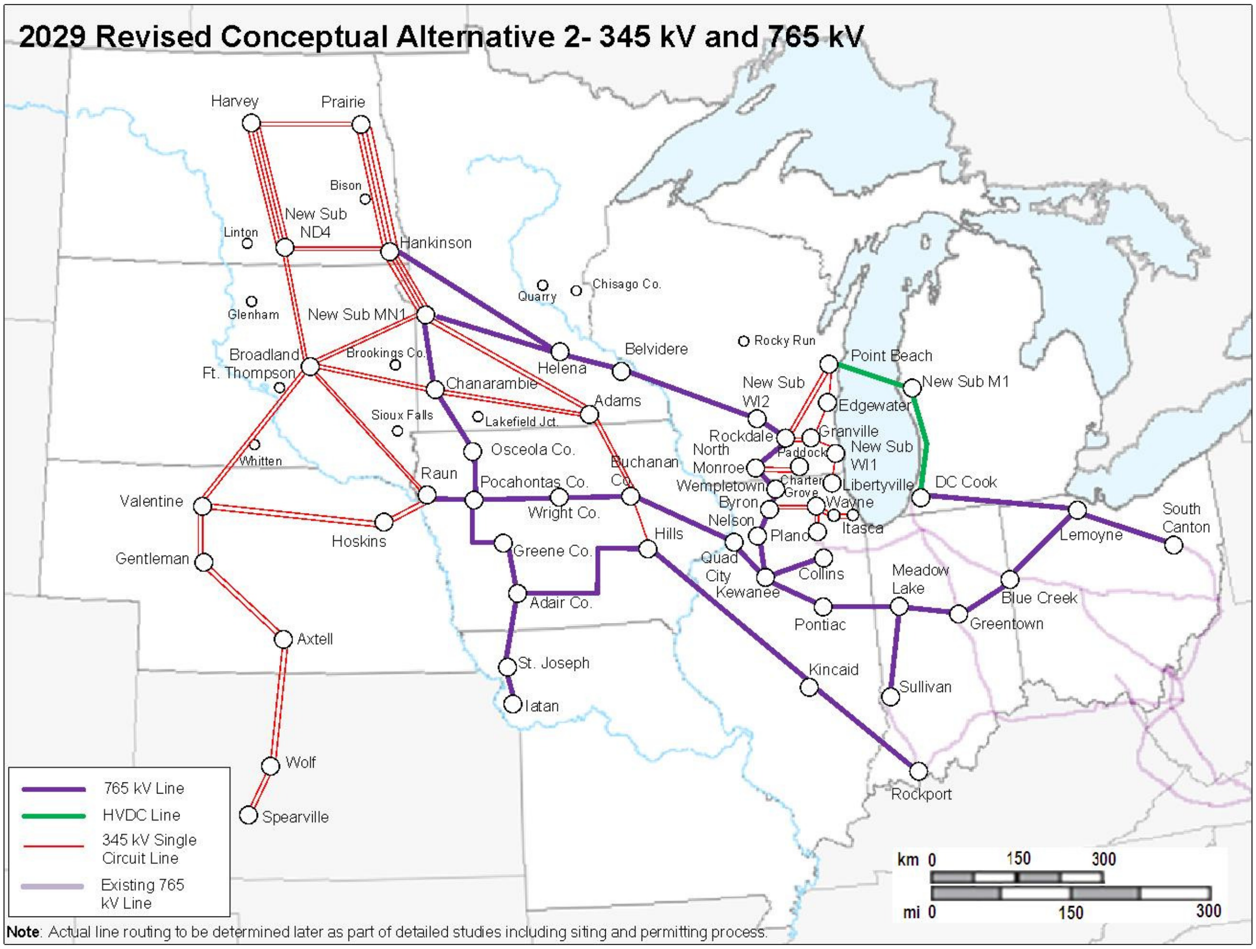


Figure 2-2 Conceptual EHV Transmission Overlay Alternative 5

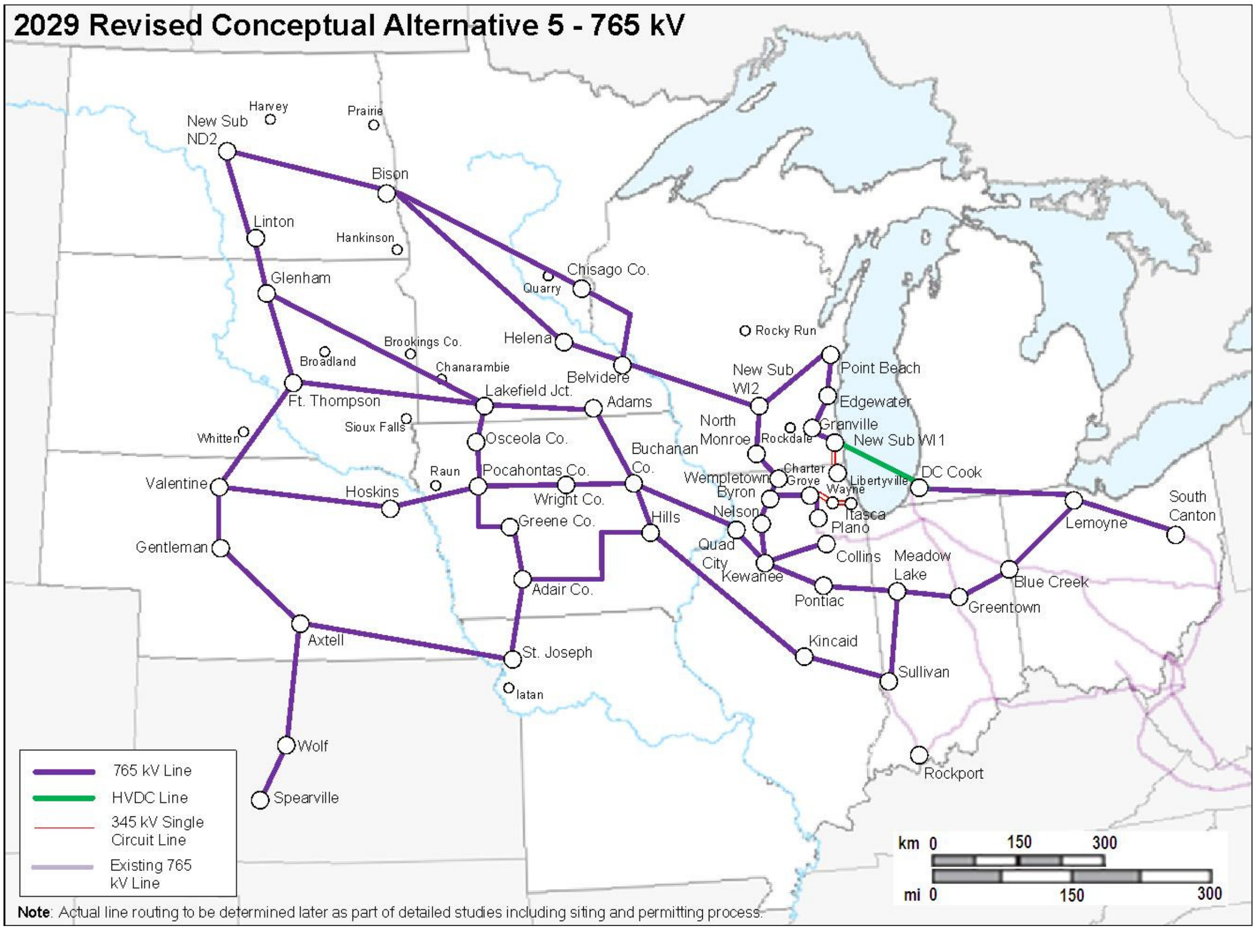
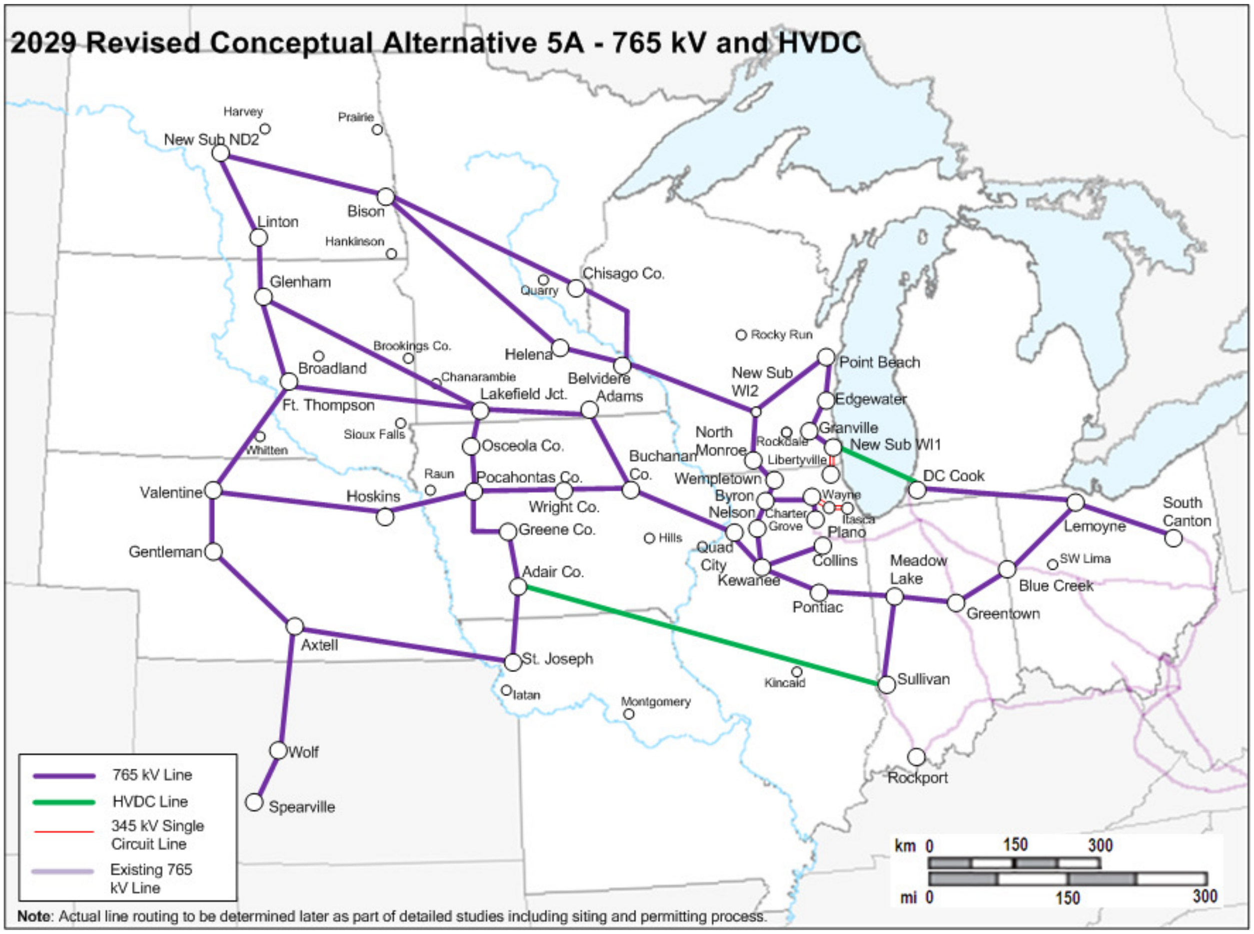


Figure 2-3 Conceptual EHV Transmission Overlay Alternative 5A

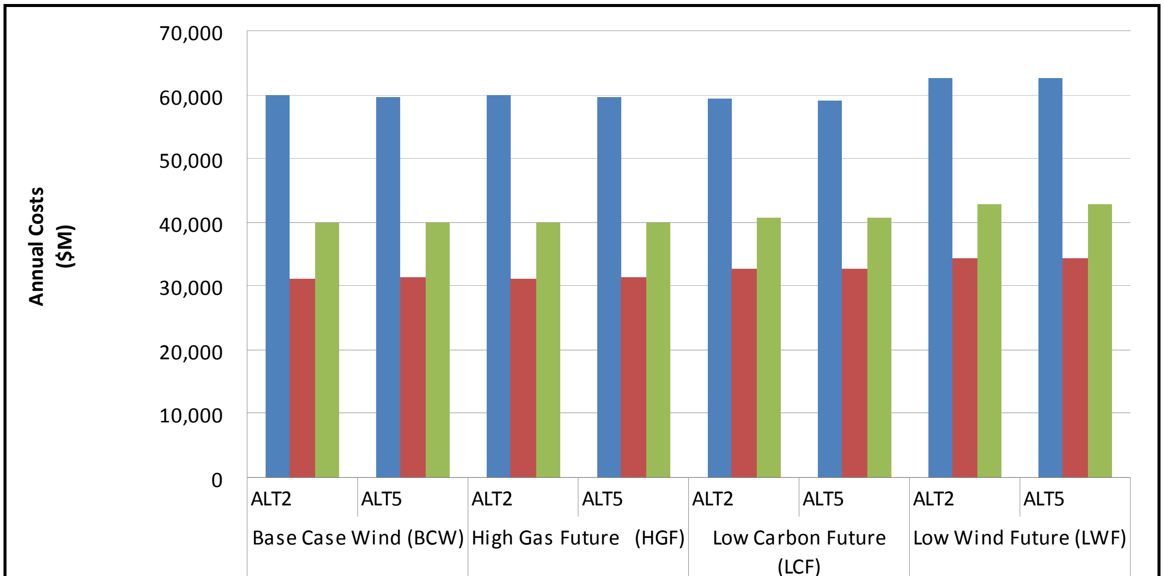


SMARTransmission transcends regional boundaries and validates the concept that a transmission overlay is required to relieve the constraints currently facing renewable generation development. The Phase 2 results give an indication of the relative economic performance of the alternatives based on a narrow set of assumptions. However, the SMARTransmission analysis is not all-encompassing. The study did not address cost allocation or routing and siting requirements, and the results are not intended to be used as the basis for RTO approval of specific projects. In addition to a more extensive market simulation, other economic benefits that could be evaluated include: economic assessment of reliability, transmission system loss reduction, wind energy transfers to the regions surrounding the study area, and operational and ancillary service benefits.

A comprehensive analysis of the economic benefits of long-term transmission plans often requires a comparison of the transmission system with and without proposed additions. This analysis would include identical fundamental input assumptions (generation, load, fuel prices) but distinct transmission configurations. Since the integration of 56.8 GW of wind generation would require a significant amount of new transmission, there is no practical “base case” against which to compare the alternatives. For this reason, Phase 2 only compares the two alternatives, as discussed further in the body of this report.

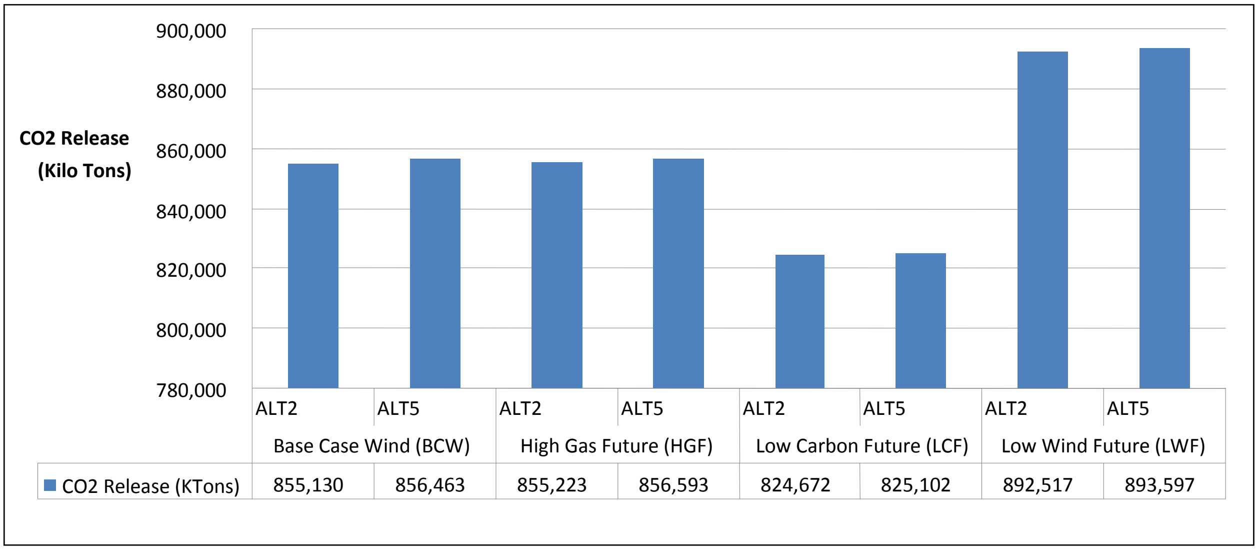
PROMOD IV, by Ventyx, was used as the security constrained economic dispatch modeling software for the SMARTransmission economic analysis. The PROMOD results indicate that Alternatives 2 and 5 are substantially similar in terms of their economic performance and ability to deliver wind generation. Apparent differences between the two alternatives are primarily attributable to the location and number of connection points to the existing lower voltage system. The final overlay could be designed to minimize these differences. Figure 2-4 and Figure 2-5 show that the differences in the economic performance are small across the various generation futures run for the study year 2029.

Figure 2-4 Annual Cost Comparison of 2029 Base Case and Futures



	BCW ALT2	BCW ALT5	HGF ALT2	HGF ALT5	LCF ALT2	LCF ALT5	LWF ALT2	LWF ALT5
Load Cost ($M)	59,907	59,748	59,819	59,649	59,343	59,152	62,416	62,416
APC ($M)	31,255	31,304	31,219	31,300	32,735	32,767	34,435	34,309
70/30 Metric ($M)	39,851	39,837	39,799	39,805	40,717	40,683	42,829	42,741

Figure 2-5 CO_2 Release Comparison of 2029 Base Case and Futures



3 Phase 2 Overview

New transmission is necessary for the United States to effectively use the country's abundant renewable resources. During Phase 2 of SMARTransmission, the Sponsor group evaluated two transmission alternatives[2] designed to enable the integration of 56.8 GW of nameplate wind generation within the study footprint. The 56.8 GW of wind generation generally reflects a Federal Renewable Portfolio Standard (RPS) requirement of 20% for all states in the SMART Study footprint. Adjustments were made for states with approved RPS requirements or goals in excess of 20%.

PROMOD IV, by Ventyx, was used as the security constrained economic dispatch modeling software for the SMARTransmission economic analysis. PROMOD IV is an electric power market simulation tool that incorporates detailed information regarding generator operating characteristics, transmission grid topology and constraints, generator commitment/operating conditions, and market system operations. The PROMOD IV model used for the 2019 Regional Generation Outlet Study (RGOS) developed by the Midwest ISO was used as the starting point to build the SMARTransmission production cost models.

Phase 2 metrics include:

- Adjusted Production Cost (APC), is the generator production costs for a given area or zone as adjusted for energy purchases from and sales outside of the zone.

- Load Cost, also referred to as load payment, is the amount consumers pay for energy in a Locational Marginal Pricing (LMP) market (before offsets like reimbursements for congestion and over-collection of losses).

- The 70/30 metric is based on the Midwest ISO's Regional Expansion Criteria & Benefits II (RECB II) metric. The study participants felt that this was a reasonable combination of the previous metrics for the purposes of this study. It is calculated according to the following formula:

  70/30 Metric = 70% * Annual APC + 30% * Annual Load Cost

- Emission Releases and Costs include the estimated amounts released and costs of CO_2, SO_2, and NO_X.

4 Wind Assumptions

Wind generation assumptions are crucial to SMARTransmission's EHV analysis. Quanta and the Sponsor group evaluated state and federal RPS requirements, estimated wind nameplate potential, and the future

[2] Phase 1 results indicated that three Alternatives - one combination 345kV and 765kV (Alternative 2), one 765kV (Alternative 5), and one 765 kV with an additional HVDC line replacing a 765 kV line (Alternative 5A) warranted additional assessment. Since Alternative 5A was substantially similar to Alternative 5, the consensus among the sponsors was that the economic results for Alternatives 5 and 5A would also be similar. As a result, economic analysis in Phase 2 was completed only on Alternatives 2 and 5.

energy contribution of wind farms to develop the wind assumptions used for the SMARTransmission study. Additional wind assumption information is available in the Phase 1 report[3].

4.1 State and Federal RPS Requirements

State RPS requirements call for states to obtain certain percentages of their retail energy sales from renewable sources by certain dates. Transmission will play an important role in enabling states to meet these requirements. The SMARTransmission Renewable Portfolio Standards (RPS) assumptions for 2029 reflect a national RPS requirement of 20% with adjustments for those states that have approved RPS requirements or goals in excess of 20%. State RPS mandates used in this study were obtained from the Database of State Incentives for Renewable and Efficiency. This information is discussed in Section 3 of the Phase 1 Report[4] and summarized in Table 4-1.

Table 4-1 Summary of State Renewable Portfolio Standards

State	Summary of RPS Requirements	SMART RPS Assumption for 2029
IA	2% by 2011 or 105 MW	20%
IL	25% by 2025	25%
IN	None	20%
MI	10% by 2015	20%
MN	25% by 2025 Xcel Energy: 30% by 2020	27.5%
MO	15% by 2021	20%
ND	10% by 2015	20%
NE	None	20%
OH	25% by 2025	25%
SD	10% by 2015	20%
WI*	10% by 2013 20% by 2020 25% by 2025	25%

* These percentages are for WI's proposed "enhanced" RPS legislation

4.2 Base Wind Nameplate Capacity

The Sponsor group evaluated the wind generation potential of each state in the study area because this information was necessary to quantify the transmission requirements that would enable the states to meet the RPS requirements in the study. The study team believed that the state wind potential should be based on consistent assumptions throughout the study area. In March 2008, the National Renewable Energy Laboratory (NREL) engaged AWS Truewind, LLC to develop wind resource and plant output data to be used for the Eastern Wind Integration Transmission Study (EWITS)[5]. SMARTransmission used the state

[3] The report is available at http://www.smartstudy.biz/.
[4] The report is available at http://www.smartstudy.biz/.
[5] The goal of EWITS was to evaluate the impact on the electric power system of increasing wind generation to meet 20% and 30% of retail electric energy sales.

wind capacities developed by NREL to allocate the wind generation potential in the study area to each of the states[6].

The calculation of the nameplate wind capacity needed to meet state RPS requirements is discussed in the Phase 1 report. Capacity requirements were based on a calculation that assumed wind energy would provide approximately 80% of the renewable requirements of each state. For those states with in-state renewable generation mandates or goals greater than 20%, SMARTransmission included the state-specific requirements.

The 9.8 GW of existing wind generation as of May 2009 was subtracted from the renewable energy requirement to establish the incremental wind generation needed to attain the RPS goals or mandates. The incremental wind generation in the study footprint was then allocated among the states in proportion to the wind capacity of the NREL Selected Sites as discussed Section 3 of the Phase 1 report**.** The nameplate wind generation value modeled by state in the Phase 2 Base Case Wind (BCW) scenario for each study year is listed in Table 4-2.

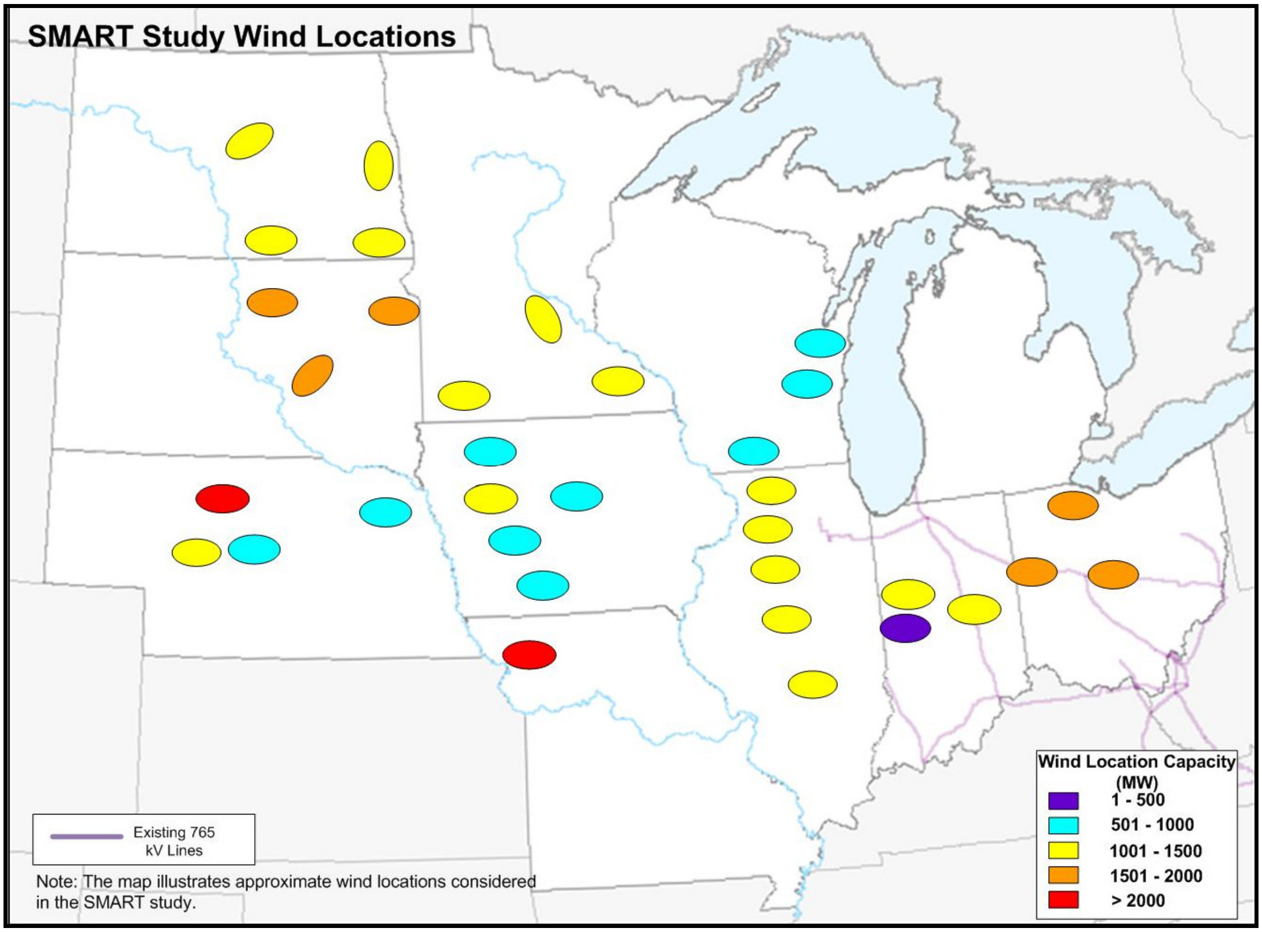
Table 4-2 Total 2029 BCW Nameplate Wind Generation by State for Phase 2

State	Wind Energy to Meet RPS Requirement Assumptions (MWh)	Total Installed Nameplate Wind Generation (MW)
IA	9,015,631	6,694
IL	34,086,968	7,919
IN	21,791,519	3,577
MI	21,766,944	8,201
MN	18,684,256	5,876
MO	17,034,255	3,070
ND	2,371,073	4,833
NE	5,625,797	5,196
OH	25,169,839	4,729
SD	2,111,696	4,208
WI	14,739,279	2,506
Total	**172,397,256**	**56,809**

[6] The methods used to develop the wind sites and capacities by state are described on the NREL website (http://wind.nrel.gov/public/EWITS).

Figure 4-1 shows the assumed locations and magnitudes of the wind farms in the SMARTransmission study footprints.

Figure 4-1 SMARTransmission Wind Locations



5 Production Cost Model Development

SMARTransmission used the inputs from Phase 1 as the starting point for the Phase 2 economic analysis. Supplementary data was added, as needed, to complete the dataset required for the PROMOD economic analysis. The primary differences in data requirements and study periods are described below.

First, the economic analysis of a transmission network requires economic data in addition to the basic load and generation assumptions used for the reliability analysis. These data points include fuel prices, generator performance characteristics, operations & maintenance (O&M) costs, as well as other relevant economic inputs.

Second, the PROMOD economic model simulates the real time operation of the transmission system. It considers each hour over a period of time, such as a year, while a powerflow model represents a single point in time. As a result, PROMOD studies consider factors that are not typically included as part of a powerflow analysis. Considerations include generation re-dispatch for transmission congestion, changes in load, and consideration of reserve margins.

Third, PROMOD economic analysis requires explicit assumptions for regions beyond the borders of the primary study area. Powerflow-based studies can minimize the impact of regions outside the study area by maintaining interchange which is the balance between load and generation. In PROMOD, interchange fluctuates over time according to economic variables. As a result, regions outside the study area must be modeled explicitly to capture the energy flows that result from incorporating economic factors into the transmission system.

This section addresses key assumptions necessary for the PROMOD analysis as well as changes from the assumptions used in Phase 1.

5.1 Starting Point Model

As mentioned previously, the 2019 Regional Generation Outlet Study (RGOS) PROMOD economic model developed by the Midwest ISO was used as the starting point for the SMARTransmission production cost models. To maintain adequate reserve margins, the Midwest ISO model included proxy generators. SMARTransmission made additional adjustments to build out the 2029 case.

5.2 Assumptions Outside of the Study Footprint

The transmission system located outside the SMARTransmission Study area was assumed to be identical to that of the Midwest ISO RGOS model. To maintain an adequate reserve margin in the 2029 model, demand and energy were not increased outside the study area for the period between 2019 and 2029. This assumes that areas outside the SMARTransmission Study area will maintain their own reserve capacities and will not rely upon capacity inside the SMARTransmission Study footprint for their reserve margin needs.

5.3 Michigan

The Renewable Portfolio Standard (RPS) for Michigan requires that 100% of the mandate be achieved using local renewable generation resources. As a result, Phase 1 of the study did not model the new generation required to meet the Michigan RPS. It was assumed that renewable generation could displace existing generation without having a significant impact on the reliability results. Since additional generation was not explicitly modeled as part of Phase 1, Michigan was treated similarly to areas outside the study footprint for Phase 2. In other words, Michigan's energy and demand were not increased between 2019 and 2029.

5.4 Key Economic Assumptions for the Study Footprint

The key economic assumptions used in the Phase 2 analysis were substantially similar to those the Midwest ISO made in the RGOS study. A summary of these assumptions is shown Table 5-1. Demand and energy assumptions were adjusted to accommodate the assumptions made during the reliability phase of the SMARTransmission Study.

Table 5-1 Assumptions for the Economic Analysis (Prices in 2010 $)

Uncertainty		Unit	RGOS Study Value	SMART Study Value
Demand and Energy	Demand Growth Rate	%	1.60	Varying[1]
	Energy Growth Rate	%	2.19	Varying[1]
Fuel Prices (Starting Values)	Gas	($/MMBtu)	6.22[2]	Same[3]
	Oil	($/MMbtu)	PowerBase Default	Same[3]
	Coal	($/MMbtu)	PowerBase Default (by unit)	Same[3]
	Uranium	($/MMbtu)	1.12	Same[3]
Fuel Prices (Escalation Rates)	Gas	%	2.91	Same[3]
	Oil	%	2.91	Same[3]
	Coal	%	2.91	Same[3]
	Uranium	%	2.91	Same[3]
Emission Costs	SO_2	($/ton)	PowerBase Default[4,6]	Same[3]
	NOx	($/ton)	PowerBase Default[5,6]	Same[3]
	CO_2	($/ton)	0[7]	Same[3]
	HG	($/ton)	60000000.0	0
O&M for New Wind	Variable O&M	($/MWh)	5.46[8]	Same[3]
Wind Profile	Hourly Wind Profile		As collected by NREL for new wind power development in 2004-2006	Same[3]

1. Demand growth rates and energy growth rates used in the Phase 2 production cost model are listed in Table B-1 in Appendix B.
2. Henry Hub 2010 gas price forecast.
3. The same as the Midwest ISO RGOS model.
4. Ventyx SO2 annual and seasonal allowance price forecast: $525.72 in 2019, $466.22 in 2024, $274.80 in 2029.
5. Ventyx NOx annual allowance price forecast: $564.66 in 2019, $574.37 in 2024, $626.94 in 2029. NOx seasonal allowance price is modeled as zero in this study.
6. Ventyx uses a proprietary emission price forecast model (EFM) to simulate emission control decisions and results simultaneously in the three cap-and-trade markets (SO_2, NOx Annual, and NOx Seasonal).
7. Non-zero carbon tax values were used in the carbon tax sensitivity studies.
8. Midwest ISO confirmed that the variable O&M value used in the RGOS study for the new wind farms came from the Eastern Wind Integration and Transmission Study (EWITS).

5.5 Powerflow Model

The power flow models used in the Phase 2 analysis for each study year and each Alternative are those developed in the SMARTransmission Phase 1 study.

5.6 Event File

PROMOD software uses an event file to define transmission system contingencies and flowgates to be monitored during the security commitment and dispatch of generation resources. The event file used in the SMARTransmission Phase 2 study was taken from the 2019 Midwest ISO RGOS study, which contains Midwest ISO and NERC flowgates and the local contingencies. With the help from Midwest ISO staff, new constraints and flowgates associated with the new wind generation were identified and added to the event file. The transmission overlays outlined in the Phase 1 study were included in the event file.

5.7 Study Footprint Wind Generation

A summary of the total wind generation capacity included within the study area (excluding Michigan since it achieves its RPS through in-state resources) can be found in Table 5-2. Alternative 2 has higher wind energy output than Alternative 5 as a result of a difference in the location (state) of the wind generators. Since the wind generation profiles are based on the location (state) of the generator, the alternatives' wind profiles and associated energy differed.

Table 5-2 Summary of Study Footprint Wind Generation

	Alternative 2			Alternative 5		
	Existing Wind	Incremental Wind	Total	Existing Wind	Incremental Wind	Total
Installed Nameplate Capacity (GW)	5.4	37.6	43.0	5.4	37.6	43.0
Scheduled Energy Output (GWh)	17,217.7	121,865.0	139,082.7	17,217.7	121,580.6	138,798.3

5.8 Phase 1 Future Non-Wind Generation

In Phase 1, new proxy non-wind generation resources were added to meet the demand increase assumed in the on-peak model. The methodology used to determine the non-wind generation by state was provided in Section A.9 of the Phase 1 report. Generation units included in Phase 2 are shown in Table C-1 in Appendix C.

5.9 Additional Non-Wind Proxy Generation

To maintain adequate reserve margins within the study footprint for the 2029 model year, additional proxy generation units were added to the model. Information on these units can be found in Appendix G.

5.10 Generation Futures Analysis

Transmission overlay Alternatives 2 and 5 were designed to meet performance criteria under the Phase 1 base case assumptions. Due to the uncertainties associated with economic and political conditions, additional future scenarios ("futures") were evaluated. To assess the robustness of each Alternative and compare performance, Phase 2 of the study evaluated the Alternatives using the following futures based on increased natural gas generation, reduced carbon emissions, and a reduced amount of wind generation.

5.10.1 High Gas Future (HGF)

The HGF assumes that natural gas–fired generation will be the preferred technology for new power plants. This future was included due to its smaller environmental footprint as compared to other fossil fuels, its flexibility in terms of use, and shorter plant construction timeframe.

The following adjustments were made to the BCW cases to develop the corresponding HGF scenarios:

- Approximately 11GW of incremental gas generation was added.

5.10.2 Low Carbon Future (LCF)

The LCF is based on the premise of decreasing carbon emitting generation resources and increasing hydro, nuclear, and wind generation. The following adjustments were made to BCW cases to develop the corresponding LCF scenarios:

- Approximately 1.6 GW of hydro power was added.
- Approximately 0.9 GW of nuclear generation was added.
- Approximately 5.6 GW of gas generation was added.
- Approximately 6.0 GW of nameplate wind generation was added in North and South Dakota and Minnesota.
- Coal units with maximum nameplate ratings of 250MW that were 40 years or older in 2010 were retired. This resulted in a reduction of 2.6 GW of coal generation.

5.10.3 Low Wind Future (LWF)

The LWF assumes that wind generation in 2029 is less than the amount in the BCW scenario. The non-wind generation used to develop the LWF case remained the same as in the BCW scenarios. The nameplate wind generation assumed in the LWF scenarios is shown in Table 5-3.

Table 5-3 Summary of Study Footprint Wind for LWF

	Alternative 2			Alternative 5		
	Existing Wind	Incremental Wind	Total	Existing Wind	Incremental Wind	Total
Installed Nameplate Capacity (GW)	5.4	21.8	27.2	5.4	21.8	27.2
Scheduled Energy Output (GWh)	17,217.7	70,141.7	87,359.4	17,217.7	70,527.0	87744.7

6 Phase 2 Metrics

The following metrics were used in Phase 2 of the study:

- Adjusted Production Cost (APC), is the generator production costs for a given area or zone as adjusted for energy purchases and sales outside of the zone. It is the production costs of the generators in a given zone plus the cost of imports into the zone (valued at the zone's load-weighted locational marginal price (LMP)) minus the revenue from energy sales out of the zone (valued at the zone's generation-weighted LMP). This metric is typically the sum of the hourly adjusted production costs for a year (i.e. the sum of 8,760 hours).

  APC is calculated using following formula:

  APC = Production Cost + Emergency Cost + Purchase Cost – Sales Revenue

  Where: Production Cost = Fuel cost + Environmental Cost + Variable O&M Cost

  Emergency Cost = Emergency MWh * $2,000/MWh

  Purchase Cost = MW Import x Zonal Load Weighted LMP

  Sales Revenues = MW Export x Zonal Generation Weighted LMP

- Load Cost, also referred to as load payment, is the amount consumers pay for energy in an LMP market (before offsets like reimbursements for congestion and over-collection of losses). It is computed based on the load weighted average zonal LMPs. Hourly load-weighted average LMP prices for each zone are multiplied by the hourly zonal loads to compute the hourly zonal load payments. The annual zonal load payment is the sum of all 8,760 hourly load payments.

  Load Cost = Zonal Load Weighted LMP x Zonal Load MWh

- The 70/30 metric is the Midwest ISO's Regional Expansion Criteria & Benefits II (RECB II) metric. The 70% APC / 30% Load Cost calculation is consistent with the Midwest ISO's RECB II economic analysis process and represents a rough approximation of the percentage of the study footprint under regulated retail rates (70%) and the percentage of the study footprint under a deregulated retail market (30%).

  70/30 Metric = 70% * Annual APC + 30% * Annual Load Cost

- Emission Release and Cost includes the estimated amounts released and costs of CO_2, SO_2, and NO_X. The emission cost, or environmental cost, is included in the production cost, but it is reported separately to provide an indication of the relative environmental impacts of the transmission overlay alternatives.

7 Summary of Results

The project team performed economic simulations for 2029 on the BCW scenario with both transmission overlay Alternatives 2 and 5. Futures cases include increased natural gas costs, reduced carbon emissions coal generation, and lower wind generation. The results included hourly generating unit output and costs and power flow across each flowgate (i.e. monitored interfaces and branches) in the model.

7.1 Load Cost, APC, and 70/30 Metric

Figure 7-1 shows the load cost, APC, and the 70/30 metrics at the system level for each of the scenarios studied.

Figure 7-2 shows that the differences between the alternatives are within the study's margin of error.

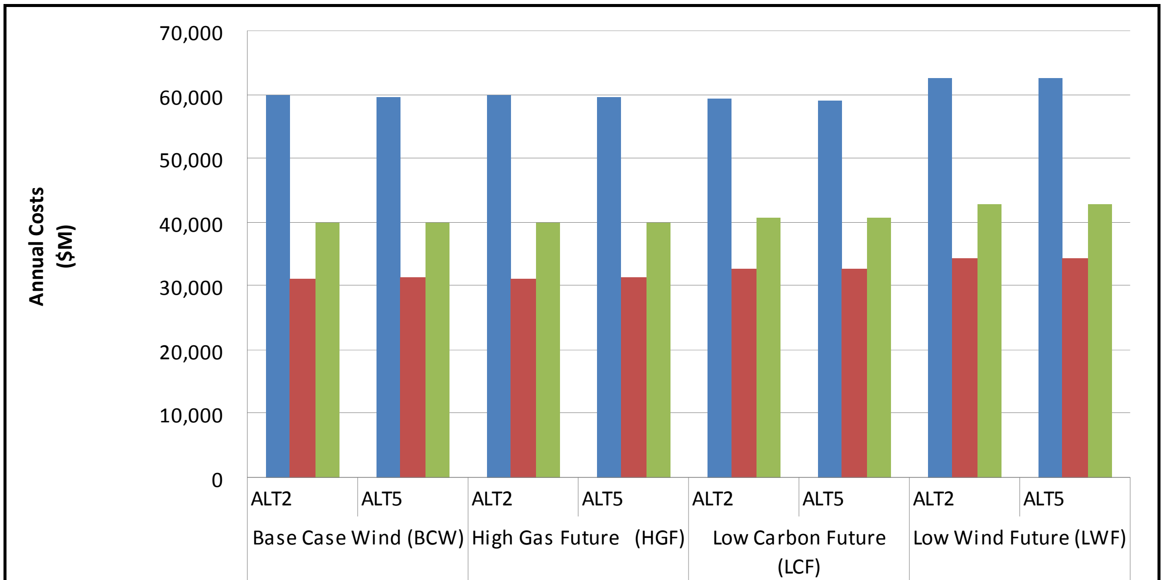
The size of the difference in Load Cost between the alternatives is driven by their relative abilities to reduce system congestion on the existing transmission system. A large portion of the difference is related to how each alternative interconnects to the existing system, particularly in the western portion of the study area. Alternative 5 has much stronger connections in Minnesota, North Dakota, and South Dakota when compared to Alternative 2. Although Alternative 2's estimated construction cost would increase, it could be adjusted to better mimic the congestion relief performance of Alternative 5.

One particular issue of note was a constraint on the Broadland 345/230 kV transformer, located in South Dakota, for Alternative 2. Since this transformer was the only location where Alternative 2 connected to the underlying system in North Dakota, South Dakota, and western Minnesota, it was heavily constrained and caused significant wind generation curtailments. The constraint was disregarded under the assumption that additional transmission would be necessary to relieve this problem.

As noted in Section 5.7, more wind energy was generated in Alternative 2 than Alternative 5 because of a difference in modeling assumptions. This would lead to a lower APC for Alternative 2 relative to Alternate 5. This difference likely would account for a significant portion of the difference in APC between the two alternatives.

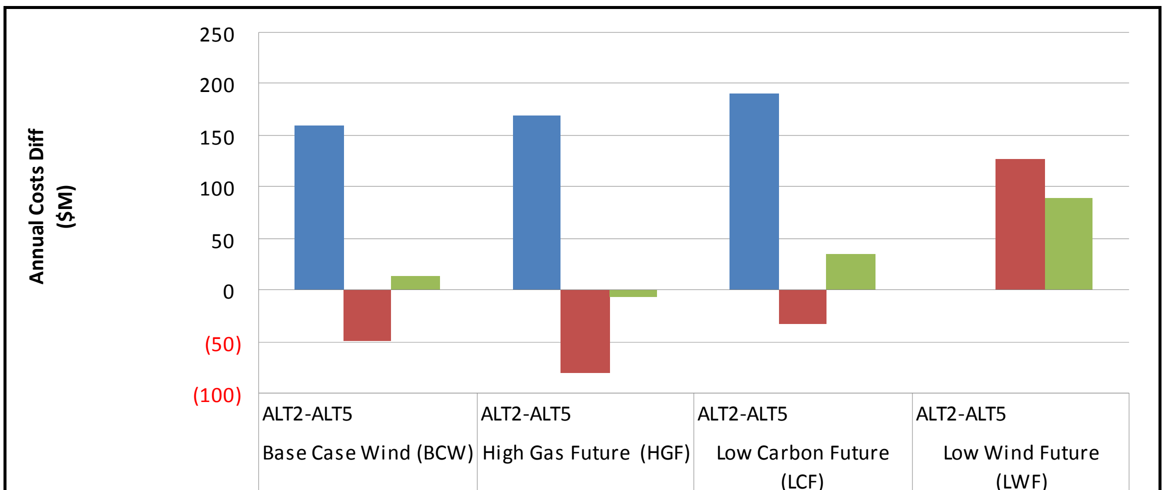
Based on the 70/30 Metric, the difference between the alternatives is small. If the modeling differences between the alternatives were addressed, the relative difference between the 70/30 metrics would likely decrease.

Figure 7-1 Annual Costs Comparison of Scenarios



	Base Case Wind (BCW) ALT2	Base Case Wind (BCW) ALT5	High Gas Future (HGF) ALT2	High Gas Future (HGF) ALT5	Low Carbon Future (LCF) ALT2	Low Carbon Future (LCF) ALT5	Low Wind Future (LWF) ALT2	Low Wind Future (LWF) ALT5
Load Cost ($M)	59,907	59,748	59,819	59,649	59,343	59,152	62,416	62,416
APC ($M)	31,255	31,304	31,219	31,300	32,735	32,767	34,435	34,309
70/30 Metric ($M)	39,851	39,837	39,799	39,805	40,717	40,683	42,829	42,741

Figure 7-2 Annual Costs Difference of Scenarios



	Base Case Wind (BCW) ALT2-ALT5	High Gas Future (HGF) ALT2-ALT5	Low Carbon Future (LCF) ALT2-ALT5	Low Wind Future (LWF) ALT2-ALT5
ΔLoad Cost ($M)	159	170	191	0
ΔAPC ($M)	(49)	(81)	(32)	126
Δ70/30 Metric ($M)	13	(6)	35	88

7.1.1 Detailed Economic Metric Results by Area

The tables in Appendix D show the load cost, APC and 70/30 metric by area for each of the futures.

7.2 Environmental Metrics

Environmental metrics encompass the release and cost of CO_2, SO_2, and NO_X emissions. As shown in Table 7-1, the emissions for the two alternatives are substantially similar across the various futures. The differences in the emissions are within the study's margin of error. Figure 7-3 and Figure 7-4 compare the CO_2 emissions for each of the scenarios.

Table 7-1 Emission Release and Cost of BCW Futures

Scenario		CO_2 Release (Kilo Tons)	SO_2 Release (Kilo Tons)	NOx Release (Kilo Tons)
Base Case Wind (BCW)	ALT2	855,130	2,078	984
	ALT5	856,463	2,077	984
	ALT2 – ALT5	(1,333)	1	0
High Gas Future (HGF)	ALT2	855,223	2,078	984
	ALT5	856,593	2,077	984
	ALT2 – ALT5	(1,370)	1	0
Low Carbon Future (LCF)	ALT2	824,672	2,004	942
	ALT5	825,102	2,002	943
	ALT2 – ALT5	(430)	2	(1)
Low Wind Future (LWF)	ALT2	892,517	2,155	1,024
	ALT5	893,597	2,155	1,021
	ALT2 – ALT5	(1,080)	0	3

Figure 7-3 CO_2 Release Comparison of BCW Scenarios

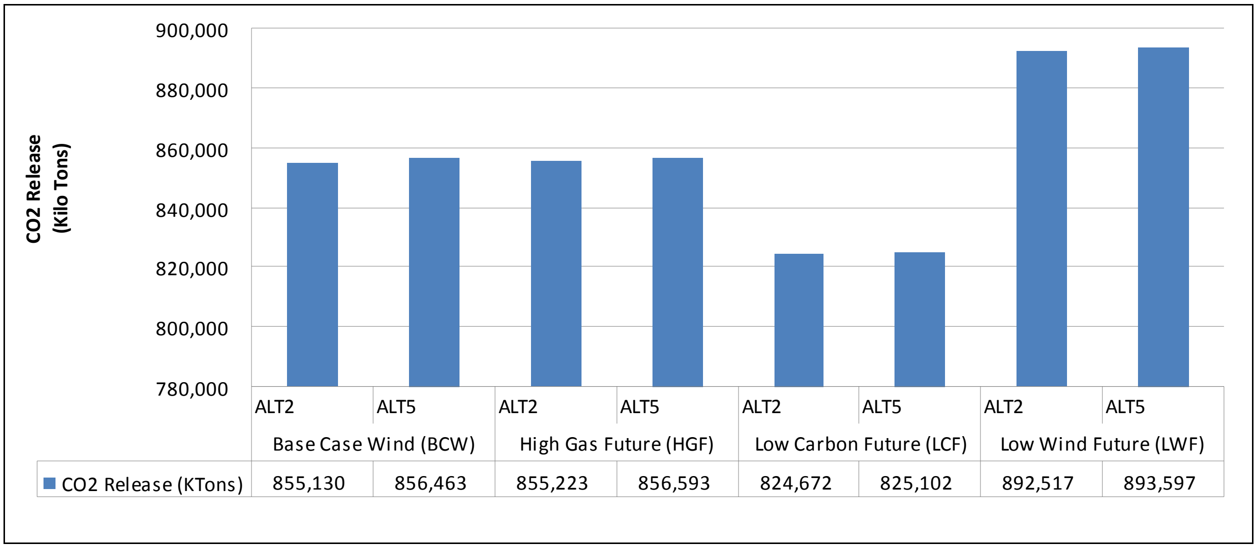
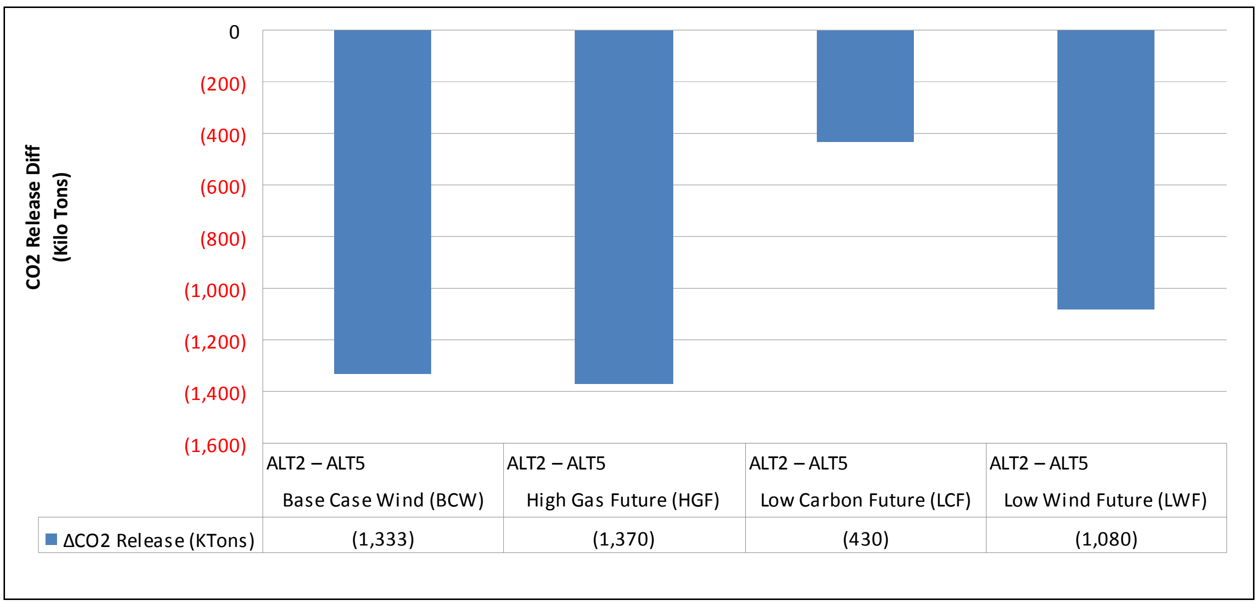


Figure 7-4 CO_2 Release Difference of BCW Scenarios



7.3 Losses

Though they are not included as part of the PROMOD analysis for this study, transmission system losses are an important economic consideration. Table 7-2 shows the differences in losses between Alternative 2 and Alternative 5 for both the on-peak and off-peak scenarios. These figures were taken from the power flow models used in Phase 1. The reduction in off-peak losses for Alternative 5 compared to Alternative 2 is due to a greater use of 765kV in the western portion of the study footprint.

Table 7-2 Losses

	On-Peak Losses (MW)	Off-Peak Losses (MW)
ALT2	7,148	5,586
ALT5	7,153	5,046
Difference (ALT2 – ALT5)	(5)	540

8 Conclusions

SMARTransmission was designed to encourage transmission development in support of wind generation. The study looks across the seams of the Mid-continent Area Power Pool (MAPP) and three Regional Transmission Organizations – SPP, Midwest ISO and PJM and validates the idea that a transmission overlay would relieve the constraints currently facing wind generation. However, the SMARTransmission analysis is not comprehensive. The study did not address routing and siting requirements, and the results are not intended to be used as the basis for RTO approval of specific projects. In addition to a more extensive market simulation, other economic benefits that could be evaluated include: economic assessment of reliability, transmission system loss reduction, wind energy transfers to the regions surrounding the study area, and operational and ancillary service benefits.

Phase 1 of the study resulted in three transmission overlay alternatives that could reliably transfer the energy from the western part of the study area to the eastern part. The results of Phase 2 indicate that the two alternatives studied have substantially similar economic and environmental performance as well as abilities to reliably deliver wind generation. Results of the transmission security constrained economic simulation are shown in Table 8-1. The slight difference between the economic performances of the two alternatives seems to be primarily due to the difference in the connection points of the two alternatives to the existing lower voltage system. Although Alternative 2's estimated construction cost would increase, it could be modified to better mimic the congestion relief performance of Alternative 5. The futures analysis also supports the conclusion that Alternatives 2, 5, and 5A are substantially similar.

Table 8-1 Base Case Wind Economic Analysis Results

Base Case Wind (BCW)	ALT2	ALT5	Difference	% Difference
Load Costs ($M)	59,907	59,748	159	0.3%
APC ($M)	31,255	31,304	(49)	0.2%
70/30 Metric ($M)	39,851	39,837	13	< 0.1%
CO_2 Release (Kilo Tons)	855,130	856,463	(1,333)	0.2%
SO_2 Release (Kilo Tons)	2,078	2,077	1	< 0.1%
NO_x (Kilo Tons)	984	984	0	0.0%

SMARTransmission was designed to integrate substantial amounts of local wind generation and enable the transfer of wind energy from states that have high wind generation capacity factors to those with lower wind generation capacity factors. The combined results of the Phase 1 and Phase 2 indicate that Alternatives 2, 5 and 5A perform similarly with regard to their abilities to transfer wind energy across the study area, their economic performance, and their impact on the environment.

Appendix A PROMOD Area Structure

The SMARTransmission Study focuses on areas within North and South Dakota, Iowa, Indiana, Ohio, Illinois, Minnesota, Missouri, Nebraska, Michigan, and Wisconsin. The Study area is spread across three Regional Transmission Organizations (RTOs) – Midwest ISO, PJM, and SPP. In the transmission security constrained production cost model developed in Phase 2, thirty-four (34) areas (or zones) were defined as listed in Table A-1 to cover the entire study footprint.

Table A-1 PROMOD Area Definition

RTO	PROMOD Area	Description
MISO	ALWFT	Alliant West
	AM_IL	Ameren Illinois (AmerenCIPS, AmerenCILCO, and AmerenIP)
	AMRNUE	Ameren Missouri, Columbia Water and Light
	CIN	Duke Energy Midwest (Cinergy)
	DETED	Detroit Edison (International Transmission Company)
	DPC	Dairyland Power Cooperative
	FEOHIO	FirstEnergy Ohio
	GRE	Great River Energy
	HEC	Hoosier Energy
	IP&L	Indianapolis Power & Light Company
	MDU (in WAPA)	Montana Dakota Utilities Company
	MGE	Madison Gas & Electric Company
	MICHIGAN	Michigan Electric Transmission Company
	MIDAM	MidAmerican Energy Company
	MPL	Minnesota Power Inc.
	MPW	Muscatine Power & Water
	NIPSCO	Northern Indiana Public Service Company
	NSP	Northern States Power Company (Xcel)
	OTP	Otter Tail Power Company
	SIGE	Vectren
	SIPC	Southern Illinois Power Coop
	SMMPA	Southern Minnesota Municipal Power Agency
	SPRIL	City Water Light & Power (Springfield, IL)
	WEP	Wisconsin Energy Corporation, Upper Peninsula Power Company
	WPL	Alliant East
	WPS	Wisconsin Public Service Corporation
PJM	AEP	American Electric Power, Ohio Valley Electric Corporation
	DP&L	Dayton Power & Light
	PJMNIC	Commonwealth Edison Company (ComEd)
SPP	LES	Lincoln Electric System
	MIPU[1]	Aquila – Missouri Public Service
	NPPD	Nebraska Public Power District
	OPPD	Omaha Public Power District
N/A	WAPA	WAPA Billings East – Dakotas, Minnesota, Nebraska, and Iowa

1. MIPU is included in Phase 2 due to the fact that a new wind farm modeled by SMARTransmission study is located within its service territory.

Appendix B Demand & Energy Growth Rate by Area

Estimated annual peak demand and energy growth rates by area are listed in Table B-1.

Table B-1 Annual Demand & Energy Growth Rate

RTO	Area	Annual Peak & Energy Growth Rate
MISO	ALWFT	1.00%
	AM_IL	1.40%
	AMRNUE	1.40%
	CIN	1.40%
	DETED[2]	1.40%
	DPC	1.00%
	FEOHIO	1.40%
	GRE	1.00%
	HEC	1.40%
	IP&L	1.40%
	MDU	1.00%
	MGE	1.40%
	MICHIGAN[2]	1.40%
	MIDAM	1.00%
	MPL	1.00%
	MPW	1.00%
	NIPSCO	1.40%
	NSP	1.00%
	OTP	1.00%
	SIGE	1.40%
	SIPC	1.40%
	SMMPA	1.00%
	SPRIL	1.40%
	WEP	1.40%
	WPL	1.40%
	WPS	1.40%
PJM	AEP	0.85%
	DP&L	1.40%
	PJMNIC	1.40%
SPP	LES	1.00%
	MIPU[1]	1.25% / 1.65%
	NPPD	1.00%
	OPPD	1.00%
N/A	WAPA	1.00%

1. MIPU used 1.25% for annual peak demand growth rate and 1.65% for annual energy growth rate as the Midwest ISO RGOS model.
2. In the 2029 revised model, demand and energy growth rate for Michigan was set to be zero.

Appendix C Future Non-Wind Generation

Table C-1 Future Non-Wind Generation

State	Area	Bus No.	Bus Name	Pmax	Fuel Type
IA	ALWFT	631139	HAZLTON3	600	ST Coal
IA	MIDAM	635630	BOONVIL3	200	CT Gas
IA	MIDAM	635680	BONDRNT3	600	ST Coal
IL	AM_IL	347850	7NORRIS	600	ST Coal
IL	AM_IL	347962	7PAWNEE	600	CT Gas
IL	AM_IL	348747	7BROKAW T2	600	CT Gas
IN	CIN	249508	08DRESSR	600	CT Gas
IN	NIPSCO	255108	17MCHCTY	600	ST Coal
MI	MICHIGAN	256143	18FILRCT	600[1]	ST Coal
MI	MICHIGAN	256196	18LTSRDJ	600[1]	ST Coal
MI	MICHIGAN	256026	18THETFD	1226[1]	CT Gas
MN	NSP	601001	FORBES 2	600	ST Coal
MN	NSP	601011	SHERCO 3	600	ST Coal
MN	NSP	601011	SHERCO 3	600	ST Coal
MO	AMMO	345669	7RUSH	600	CT Gas
MO	AMMO	346004	GOSCKMO1	600	CT Gas
NE	OPPD	645740	S3740 3	200	CT Gas
OH	FEOHIO	238569	02BEAVER	600	CT Gas
OH	FEOHIO	238961	02MIDWAY	600	CT Gas
OH	FEOHIO	239092	02SAMMIS	600	ST Coal
OH	CIN	249501	08BATESV	600	ST Coal
OH	CIN	249508	08DRESSR	600	CT Gas
OH	CIN	249522	08VERM M	600	CT Gas
OH-IN	AEP	242940	05MUSKNG	600	ST Coal
OH-IN	AEP	242605	05CLNCHR	534	ST Coal
OH-IN	AEP	940300	Spor-Water Tap	1200	IGCC
SD	WAPA	652519	OAHE 4	600	ST Coal
WI	MGE	699157	COL 345	600	ST Coal
WI	WPS	699785	ROCKY RN	600	CT Gas
Total				**17,760**	

1. This unit was taken out from the 2029 revised model where Michigan demand and energy was kept constant at the 2019 level.

Appendix D Annual Summary of Costs by Area

Table D-1 Annual Summary by Area – Costs of 2029 BCW Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	ΔLoad Cost ($M)	ΔAPC ($M)	Δ70/30 Metric ($M)
AEP	9,060	4,483	5,856	8,981	4,493	5,839	79	(10)	17
ALWFT	1,105	607	756	1,125	621	772	(20)	(14)	(16)
AM_IL	2,974	1,901	2,223	2,941	1,891	2,206	33	10	17
AMRNUE	3,083	1,941	2,284	3,101	1,941	2,289	(18)	0	(5)
CIN	6,275	4,985	5,372	6,211	4,968	5,341	64	17	31
DETED	3,423	2,401	2,708	3,387	2,393	2,691	36	8	16
DP&L	1,058	833	901	1,049	832	897	9	1	3
DPC	297	213	238	332	222	255	(35)	(9)	(17)
FEOHIO	4,976	3,242	3,762	4,909	3,236	3,738	67	6	24
GRE	737	543	601	805	590	655	(68)	(47)	(53)
HEC	701	378	475	691	377	471	10	1	4
IP&L	1,711	1,107	1,288	1,723	1,111	1,295	(12)	(4)	(6)
LES	226	184	197	206	167	179	20	17	18
MDU	127	92	103	143	97	111	(16)	(5)	(8)
MGE	251	102	147	251	102	147	0	0	0
MICHIGAN	2,973	2,058	2,333	2,941	2,049	2,317	32	9	16
MIDAM	1,406	(110)	345	1,331	(61)	357	75	(49)	(12)
MIPU	586	(370)	(83)	584	(316)	(46)	2	(54)	(37)
MPL	593	326	406	632	318	412	(39)	8	(6)
MPW	56	46	49	58	46	50	(2)	0	(1)
NIPSCO	1,355	978	1,091	1,340	976	1,085	15	2	6
NPPD	606	(639)	(266)	594	(708)	(317)	12	69	52
NSP	2,360	252	884	2,543	264	948	(183)	(12)	(63)
OPPD	574	369	431	515	359	406	59	10	25
OTP	242	113	152	262	110	156	(20)	3	(4)
PJMNIC	6,499	2,821	3,924	6,408	2,807	3,887	91	14	37
SIGE	794	649	693	779	643	684	15	6	9
SIPC	98	103	102	97	102	101	1	1	1
SMMPA	175	118	135	212	126	152	(37)	(8)	(17)
SPRIL	118	96	103	118	96	103	0	0	0
WAPA	1,146	(1,142)	(456)	1,166	(1,105)	(424)	(20)	(37)	(32)
WEP	2,314	1,250	1,569	2,305	1,251	1,567	9	(1)	2
WPL	869	672	731	873	654	720	(4)	18	11
WPS	1,139	653	799	1,135	652	797	4	1	2
Grand Total	59,907	31,255	39,851	59,748	31,304	39,837	159	(49)	13

Table D-2 Annual Summary by Area – Costs of 2029 HGF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	ΔLoad Cost ($M)	ΔAPC ($M)	Δ70/30 Metric ($M)
AEP	9,053	4,484	5,855	8,979	4,494	5,840	74	(10)	15
ALWFT	1,101	605	754	1,118	620	769	(17)	(15)	(16)
AM_IL	2,977	1,899	2,222	2,946	1,888	2,205	31	11	17
AMRNUE	3,086	1,941	2,285	3,114	1,944	2,295	(28)	(3)	(11)
CIN	6,236	4,969	5,349	6,223	4,971	5,347	13	(2)	3
DETED	3,425	2,401	2,708	3,367	2,399	2,689	58	2	19
DP&L	1,055	833	900	1,049	832	897	6	1	3
DPC	296	213	238	329	221	253	(33)	(8)	(16)
FEOHIO	4,979	3,243	3,764	4,911	3,236	3,739	68	7	25
GRE	736	542	600	799	588	651	(63)	(46)	(51)
HEC	693	376	471	690	376	470	3	0	1
IP&L	1,687	1,102	1,278	1,726	1,112	1,296	(39)	(10)	(19)
LES	226	183	196	205	167	178	21	16	18
MDU	127	92	103	142	97	111	(15)	(5)	(8)
MGE	251	102	147	250	102	146	1	0	0
MICHIGAN	2,975	2,058	2,333	2,930	2,047	2,312	45	11	21
MIDAM	1,401	(111)	343	1,324	(61)	355	77	(50)	(12)
MIPU	587	(371)	(84)	584	(317)	(47)	3	(54)	(37)
MPL	593	326	406	630	319	412	(37)	7	(6)
MPW	56	46	49	58	46	50	(2)	0	(1)
NIPSCO	1,358	979	1,093	1,339	975	1,084	19	4	8
NPPD	605	(639)	(266)	593	(708)	(318)	12	69	52
NSP	2,356	250	882	2,524	262	941	(168)	(12)	(59)
OPPD	573	368	430	513	359	405	60	9	24
OTP	242	112	151	261	110	155	(19)	2	(4)
PJMNIC	6,505	2,820	3,926	6,388	2,803	3,879	117	17	47
SIGE	782	644	685	771	640	679	11	4	6
SIPC	98	103	102	98	103	102	0	0	0
SMMPA	174	118	135	210	126	151	(36)	(8)	(16)
SPRIL	118	96	103	118	96	103	0	0	0
WAPA	1,144	(1,141)	(456)	1,163	(1,103)	(423)	(19)	(38)	(32)
WEP	2,316	1,250	1,570	2,298	1,250	1,564	18	0	5
WPL	869	672	731	869	653	718	0	19	13
WPS	1,139	654	800	1,130	653	796	9	1	3
Grand Total	59,819	31,219	39,799	59,649	31,300	39,805	170	(81)	(6)

Table D-3 Annual Summary by Area – Costs of 2029 LCF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	ΔLoad Cost ($M)	ΔAPC ($M)	Δ70/30 Metric ($M)
AEP	8,977	4,536	5,868	8,911	4,547	5,856	66	(11)	12
ALWFT	1,134	698	829	1,218	743	886	(84)	(45)	(57)
AM_IL	2,950	2,036	2,310	2,915	2,023	2,291	35	13	20
AMRNUE	3,033	2,005	2,313	3,008	2,008	2,308	25	(3)	5
CIN	6,273	5,074	5,434	6,231	5,067	5,416	42	7	18
DETED	3,383	2,398	2,694	3,328	2,396	2,676	55	2	18
DP&L	1,050	832	897	1,044	832	896	6	0	2
DPC	313	214	244	352	223	262	(39)	(9)	(18)
FEOHIO	4,944	3,498	3,932	4,880	3,487	3,905	64	11	27
GRE	648	507	549	683	555	593	(35)	(48)	(44)
HEC	697	418	502	691	417	499	6	1	3
IP&L	1,727	1,109	1,294	1,759	1,119	1,311	(32)	(10)	(17)
LES	235	195	207	208	173	184	27	22	24
MDU	121	88	98	134	94	106	(13)	(6)	(8)
MGE	247	133	167	248	133	168	(1)	0	(0)
MICHIGAN	2,938	2,249	2,456	2,898	2,233	2,433	40	16	23
MIDAM	1,447	(78)	380	1,432	(34)	406	15	(44)	(26)
MIPU	568	(357)	(80)	566	(311)	(48)	2	(46)	(32)
MPL	507	363	406	538	358	412	(31)	5	(6)
MPW	60	51	54	64	51	55	(4)	0	(1)
NIPSCO	1,337	975	1,084	1,322	972	1,077	15	3	7
NPPD	591	(657)	(283)	602	(730)	(330)	(11)	73	48
NSP	2,352	420	1,000	2,377	386	983	(25)	34	16
OPPD	604	435	486	543	410	450	61	25	36
OTP	230	112	147	246	111	152	(16)	1	(4)
PJMNIC	6,353	3,072	4,056	6,306	3,068	4,039	47	4	17
SIGE	783	644	686	770	640	679	13	4	7
SIPC	97	103	101	96	103	101	1	0	0
SMMPA	175	142	152	208	157	172	(33)	(15)	(20)
SPRIL	118	96	103	118	96	103	0	0	0
WAPA	1,132	(1,107)	(435)	1,155	(1,077)	(407)	(23)	(30)	(28)
WEP	2,302	1,251	1,566	2,287	1,250	1,561	15	1	5
WPL	865	702	751	873	686	742	(8)	16	9
WPS	1,152	578	750	1,141	581	749	11	(3)	1
Grand Total	59,343	32,735	40,717	59,152	32,767	40,683	191	(32)	35

Table D-4 Annual Summary by Area – Costs of 2029 LWF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	Load Cost ($M)	APC ($M)	70/30 Metric ($M)	ΔLoad Cost ($M)	ΔAPC ($M)	Δ70/30 Metric ($M)
AEP	9,322	5,090	6,360	9,276	5,093	6,348	46	(3)	12
ALWFT	1,188	602	778	1,195	603	781	(7)	(1)	(3)
AM_IL	3,101	1,874	2,242	3,083	1,863	2,229	18	11	13
AMRNUE	3,128	1,940	2,296	3,143	1,943	2,303	(15)	(3)	(7)
CIN	6,182	4,932	5,307	6,158	4,930	5,298	24	2	9
DETED	3,531	2,407	2,744	3,493	2,406	2,732	38	1	12
DP&L	1,079	834	908	1,076	834	907	3	0	1
DPC	321	218	249	332	221	254	(11)	(3)	(5)
FEOHIO	5,079	3,299	3,833	5,029	3,294	3,815	50	5	19
GRE	818	577	649	860	600	678	(42)	(23)	(29)
HEC	690	376	470	686	376	469	4	0	1
IP&L	1,597	1,079	1,234	1,615	1,085	1,244	(18)	(6)	(10)
LES	267	194	216	259	186	208	8	8	8
MDU	136	92	105	150	94	111	(14)	(2)	(6)
MGE	266	96	147	266	97	148	0	(1)	(1)
MICHIGAN	3,086	2,085	2,385	3,054	2,077	2,370	32	8	15
MIDAM	1,548	230	625	1,531	232	622	17	(2)	4
MIPU	608	(114)	103	610	(104)	110	(2)	(10)	(8)
MPL	650	316	416	678	308	419	(28)	8	(3)
MPW	62	47	52	63	47	52	(1)	0	(0)
NIPSCO	1,419	990	1,119	1,402	987	1,112	17	3	7
NPPD	706	(274)	20	741	(336)	(13)	(35)	62	33
NSP	2,625	649	1,242	2,727	639	1,265	(102)	10	(24)
OPPD	666	365	455	653	363	450	13	2	5
OTP	268	108	156	286	105	159	(18)	3	(3)
PJMNIC	6,985	3,336	4,431	6,917	3,330	4,406	68	6	25
SIGE	789	647	690	782	644	685	7	3	4
SIPC	98	103	102	98	103	102	0	0	0
SMMPA	194	121	143	209	124	150	(15)	(3)	(7)
SPRIL	126	97	106	126	96	105	0	1	1
WAPA	1,301	(578)	(14)	1,364	(608)	(16)	(63)	30	2
WEP	2,461	1,368	1,696	2,449	1,367	1,692	12	1	4
WPL	921	673	747	920	656	735	1	17	12
WPS	1,198	656	819	1,185	654	813	13	2	5
Grand Total	62,416	34,435	42,829	62,416	34,309	42,741	0	126	88

Appendix E Annual Summary of Emission Release by Area

Table E-1 Annual Summary by Area – Emission Release of 2029 BCW Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	ΔCO_2 (Tons)	ΔNOx (Tons)	ΔSO_2 (Tons)
AEP	152,921,668	241,681	104,556	152,283,095	240,876	104,176	638,572	805	380
ALWFT	16,154,950	55,483	35,090	17,896,357	56,712	36,356	(1,741,406)	(1,229)	(1,265)
AM_IL	62,359,171	139,444	62,138	61,675,371	137,265	61,292	683,800	2,179	846
AMRNUE	48,427,167	139,171	62,905	48,406,545	139,214	62,938	20,621	(43)	(33)
CIN	68,292,120	142,756	74,080	67,856,352	141,983	73,617	435,769	773	463
DETED	52,705,159	228,123	74,017	52,305,863	226,417	73,369	399,296	1,706	648
DP&L	16,253,863	28,235	14,086	16,225,514	28,204	14,067	28,350	32	20
DPC	4,947,853	21,477	11,462	5,850,853	24,578	13,959	(903,000)	(3,101)	(2,497)
FEOHIO	58,743,743	170,295	85,971	57,887,194	168,183	84,962	856,549	2,112	1,009
GRE	12,947,211	59,574	1,483	13,564,368	61,555	1,700	(617,157)	(1,981)	(217)
HEC	9,925,246	14,672	6,131	9,896,005	14,654	6,105	29,242	19	26
IP&L	21,865,530	53,816	23,724	21,907,860	54,195	23,927	(42,330)	(379)	(204)
LES	2,838,072	4,235	0	3,032,096	4,603	0	(194,025)	(368)	0
MDU	3,156,934	7,360	0	3,214,452	7,408	0	(57,518)	(48)	0
MGE	6,262,835	10,488	6,200	6,254,574	10,452	6,174	8,261	35	26
MICHIGAN	28,700,609	107,341	72,340	28,394,091	106,454	71,720	306,518	887	621
MIDAM	29,647,664	75,620	61,695	27,809,375	71,510	58,241	1,838,289	4,110	3,454
MIPU	12,678,674	21,701	13,528	12,681,195	21,685	13,497	(2,521)	16	31
MPL	13,210,920	35,716	25,275	13,630,832	36,687	26,113	(419,912)	(972)	(838)
MPW	1,373,384	2,280	3,547	1,400,596	2,315	3,606	(27,213)	(36)	(59)
NIPSCO	21,076,799	45,051	20,884	20,765,064	44,491	20,608	311,736	560	276
NPPD	12,317,309	26,825	1,698	13,766,905	30,339	1,760	(1,449,597)	(3,514)	(61)
NSP	29,840,169	43,243	43,979	31,700,090	45,285	46,260	(1,859,922)	(2,042)	(2,281)
OPPD	14,315,229	39,024	11	13,701,045	37,369	11	614,183	1,655	0
OTP	8,776,115	16,448	1,178	8,923,452	16,791	1,269	(147,336)	(343)	(91)
PJMNIC	47,260,405	108,812	58,444	46,869,347	108,001	57,876	391,058	811	567
SIGE	12,128,364	72,730	20,411	12,100,135	72,600	20,358	28,229	129	53
SIPC	1,729,061	7,976	3,251	1,722,827	7,959	3,245	6,234	16	6
SMMPA	3,246,453	7,327	7,517	3,415,968	7,768	7,928	(169,515)	(441)	(411)
SPRIL	2,526,150	2,507	1,463	2,527,739	2,510	1,455	(1,589)	(3)	7
WAPA	17,499,349	34,107	3,484	17,734,554	34,290	3,429	(235,205)	(183)	55
WEP	34,956,039	43,740	41,747	34,857,031	43,594	41,640	99,009	146	107
WPL	12,337,421	37,330	21,743	12,431,627	38,186	22,488	(94,206)	(856)	(745)
WPS	13,708,429	33,114	19,792	13,774,420	33,193	19,874	(65,991)	(79)	(82)
Grand Total	855,130,063	2,077,702	983,832	856,462,790	2,077,327	984,020	(1,332,727)	375	(188)

Table E-2 Annual Summary by Area – Emission Release of 2029 HGF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	ΔCO_2 (Tons)	ΔNOx (Tons)	ΔSO_2 (Tons)
AEP	152,910,260	241,673	104,538	152,270,980	240,882	104,158	639,280	792	379
ALWFT	16,156,597	55,492	35,090	17,900,925	56,720	36,362	(1,744,329)	(1,228)	(1,272)
AM_IL	62,363,910	139,463	62,138	61,677,067	137,247	61,281	686,843	2,216	856
AMRNUE	48,427,052	139,186	62,905	48,401,773	139,222	62,938	25,278	(36)	(33)
CIN	68,275,601	142,729	74,022	67,870,980	141,994	73,585	404,621	735	437
DETED	52,703,183	228,124	74,017	52,311,357	226,430	73,378	391,826	1,694	640
DP&L	16,248,539	28,234	14,082	16,227,744	28,203	14,067	20,795	31	15
DPC	4,948,664	21,483	11,465	5,852,712	24,585	13,964	(904,048)	(3,103)	(2,499)
FEOHIO	58,733,340	170,278	85,956	57,886,833	168,196	84,966	846,508	2,082	990
GRE	12,939,082	59,587	1,478	13,555,283	61,565	1,693	(616,202)	(1,978)	(215)
HEC	10,002,355	14,671	6,163	9,963,680	14,653	6,129	38,674	18	34
IP&L	21,858,072	53,805	23,713	21,901,161	54,180	23,920	(43,089)	(375)	(207)
LES	2,838,315	4,235	0	3,031,981	4,602	0	(193,666)	(367)	0
MDU	3,157,674	7,363	0	3,214,241	7,407	0	(56,567)	(44)	0
MGE	6,263,237	10,491	6,202	6,252,126	10,452	6,173	11,111	39	28
MICHIGAN	28,701,000	107,310	72,329	28,396,665	106,438	71,714	304,335	872	614
MIDAM	29,648,540	75,626	61,704	27,814,476	71,521	58,248	1,834,064	4,105	3,456
MIPU	12,676,186	21,699	13,526	12,683,084	21,687	13,494	(6,898)	12	31
MPL	13,209,897	35,716	25,273	13,637,153	36,703	26,128	(427,256)	(986)	(855)
MPW	1,373,112	2,279	3,546	1,401,830	2,316	3,608	(28,718)	(37)	(62)
NIPSCO	21,074,653	45,049	20,879	20,764,102	44,484	20,602	310,551	565	277
NPPD	12,316,711	26,825	1,699	13,766,526	30,336	1,760	(1,449,815)	(3,511)	(61)
NSP	29,871,389	43,241	43,995	31,746,747	45,279	46,277	(1,875,359)	(2,039)	(2,282)
OPPD	14,312,821	39,020	11	13,695,472	37,359	10	617,348	1,661	1
OTP	8,784,192	16,452	1,184	8,936,132	16,800	1,278	(151,940)	(348)	(94)
PJMNIC	47,242,699	108,819	58,398	46,854,441	108,022	57,810	388,259	797	588
SIGE	12,135,663	72,662	20,397	12,101,547	72,561	20,345	34,116	100	52
SIPC	1,731,093	7,982	3,254	1,722,230	7,958	3,245	8,863	24	9
SMMPA	3,246,901	7,329	7,518	3,416,259	7,769	7,929	(169,357)	(440)	(410)
SPRIL	2,526,826	2,507	1,463	2,528,163	2,511	1,455	(1,337)	(4)	8
WAPA	17,538,951	34,133	3,499	17,768,288	34,271	3,447	(229,336)	(138)	51
WEP	34,961,653	43,750	41,755	34,848,107	43,600	41,638	113,547	150	117
WPL	12,336,600	37,336	21,742	12,422,738	38,174	22,470	(86,138)	(838)	(729)
WPS	13,707,890	33,118	19,791	13,770,351	33,196	19,868	(62,461)	(78)	(77)
Grand Total	855,222,658	2,077,665	983,730	856,593,155	2,077,322	983,941	(1,370,497)	343	(212)

Table E-3 Annual Summary by Area – Emission Release of 2029 Revised LCF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	ΔCO_2 (Tons)	ΔNOx (Tons)	ΔSO_2 (Tons)
AEP	151,564,076	239,581	103,604	151,089,606	239,091	103,321	474,470	490	283
ALWFT	10,936,303	37,801	21,533	12,503,603	39,023	22,631	(1,567,301)	(1,222)	(1,098)
AM_IL	61,431,925	137,912	61,508	60,727,960	135,619	60,532	703,965	2,293	976
AMRNUE	47,757,576	137,299	62,007	47,704,344	137,239	61,980	53,232	60	27
CIN	68,404,011	142,913	74,059	67,958,490	142,110	73,604	445,521	803	455
DETED	52,359,318	226,700	73,474	51,950,842	224,993	72,842	408,476	1,708	632
DP&L	16,231,536	28,190	14,062	16,232,806	28,175	14,057	(1,269)	15	5
DPC	4,955,709	21,450	11,485	6,067,134	25,381	14,560	(1,111,426)	(3,930)	(3,075)
FEOHIO	58,458,817	169,642	85,606	57,659,671	167,670	84,613	799,146	1,972	993
GRE	12,228,624	55,325	1,553	12,667,308	56,328	1,830	(438,684)	(1,003)	(277)
HEC	9,991,402	14,654	6,156	9,953,918	14,631	6,123	37,484	23	33
IP&L	21,974,674	54,325	23,971	22,008,024	54,622	24,162	(33,350)	(297)	(191)
LES	2,371,750	2,995	0	2,553,790	3,353	0	(182,041)	(359)	0
MDU	3,215,047	7,650	0	3,163,523	7,369	0	51,524	281	0
MGE	6,051,362	10,224	6,028	5,931,591	10,065	5,912	119,772	159	115
MICHIGAN	28,441,923	106,524	71,766	28,132,292	105,673	71,141	309,631	851	625
MIDAM	27,428,552	67,337	58,304	25,994,567	64,221	55,521	1,433,985	3,116	2,783
MIPU	12,096,791	21,161	13,326	12,202,866	21,256	13,356	(106,075)	(95)	(29)
MPL	12,315,743	34,250	23,343	12,466,751	34,670	23,771	(151,008)	(421)	(428)
MPW	970,637	558	1,367	1,009,320	582	1,423	(38,683)	(24)	(56)
NIPSCO	20,662,340	44,310	20,508	20,388,273	43,828	20,257	274,067	482	251
NPPD	11,435,468	24,616	1,672	12,938,976	28,123	1,790	(1,503,507)	(3,507)	(118)
NSP	21,469,061	32,152	31,527	23,196,606	34,337	34,022	(1,727,546)	(2,185)	(2,494)
OPPD	9,320,665	24,938	13	8,843,772	23,716	10	476,893	1,222	2
OTP	8,704,617	16,352	1,113	8,717,764	16,356	1,179	(13,147)	(3)	(66)
PJMNIC	46,208,631	106,553	56,990	45,868,585	105,814	56,537	340,046	738	453
SIGE	12,129,301	72,686	20,405	12,095,283	72,534	20,339	34,018	152	66
SIPC	1,712,891	7,912	3,224	1,699,692	7,880	3,210	13,199	32	14
SMMPA	2,700,840	6,405	6,340	2,958,440	7,020	6,949	(257,600)	(615)	(609)
SPRIL	2,516,151	2,495	1,457	2,505,556	2,488	1,447	10,595	7	10
WAPA	18,709,184	37,201	3,650	18,218,969	35,394	3,505	490,214	1,807	145
WEP	34,383,868	43,236	41,346	34,146,614	42,856	40,998	237,254	380	348
WPL	12,006,066	36,338	21,146	12,161,911	37,394	22,221	(155,845)	(1,056)	(1,075)
WPS	13,527,199	32,550	19,510	13,383,304	32,198	19,310	143,895	351	200
Grand Total	824,672,059	2,004,237	942,054	825,102,153	2,002,010	943,153	(430,093)	2,226	(1,099)

Table E-4 Annual Summary by Area – Emission Release of 2029 Revised LWF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	CO_2 (Tons)	NOx (Tons)	SO_2 (Tons)	ΔCO_2 (Tons)	ΔNOx (Tons)	ΔSO_2 (Tons)
AEP	157,333,518	249,016	107,376	156,883,798	248,646	107,082	449,720	369	294
ALWFT	18,305,367	59,684	38,236	18,920,776	60,117	38,583	(615,409)	(433)	(347)
AM_IL	64,091,634	144,341	64,017	63,610,177	142,951	63,531	481,457	1,390	486
AMRNUE	49,111,776	140,908	63,787	49,023,018	140,750	63,710	88,758	158	77
CIN	67,846,582	142,111	73,896	67,380,256	141,194	73,367	466,326	917	529
DETED	53,407,188	230,930	75,060	53,184,509	230,008	74,680	222,680	923	380
DP&L	16,273,410	28,373	14,138	16,257,033	28,343	14,122	16,377	29	16
DPC	5,459,080	23,288	12,824	5,692,014	24,025	13,511	(232,935)	(737)	(687)
FEOHIO	59,270,165	171,690	86,796	58,641,856	170,102	86,005	628,309	1,588	791
GRE	13,773,115	63,153	1,572	13,908,498	63,128	1,665	(135,383)	25	(93)
HEC	9,930,558	14,703	6,133	9,909,197	14,692	6,113	21,361	12	20
IP&L	21,479,309	52,364	22,937	21,490,389	52,573	23,058	(11,080)	(209)	(121)
LES	3,166,858	4,823	0	3,418,353	5,319	0	(251,495)	(496)	0
MDU	3,368,487	7,982	0	3,460,531	8,205	0	(92,043)	(222)	0
MGE	6,830,785	11,160	6,680	6,771,657	11,072	6,617	59,127	87	62
MICHIGAN	29,395,533	109,020	73,691	29,204,585	108,519	73,321	190,948	501	370
MIDAM	33,998,035	84,636	69,475	33,429,128	83,426	68,421	568,906	1,210	1,055
MIPU	13,001,512	22,149	13,959	12,998,799	22,060	13,801	2,713	89	158
MPL	14,109,508	37,610	27,131	14,339,856	38,237	27,629	(230,348)	(627)	(498)
MPW	1,473,576	2,427	3,783	1,485,708	2,443	3,809	(12,132)	(16)	(27)
NIPSCO	22,142,726	46,839	21,843	21,949,204	46,552	21,678	193,522	287	164
NPPD	14,592,905	31,624	2,044	16,818,192	36,668	2,258	(2,225,287)	(5,045)	(214)
NSP	34,004,914	47,745	48,919	34,511,040	48,041	49,297	(506,125)	(296)	(378)
OPPD	16,130,662	43,839	14	15,825,633	43,031	14	305,029	807	(0)
OTP	9,150,280	17,332	1,292	9,263,789	17,610	1,367	(113,510)	(278)	(75)
PJMNIC	51,039,413	117,002	63,473	50,792,898	116,477	63,081	246,516	525	392
SIGE	12,075,549	72,555	20,319	12,047,892	72,445	20,269	27,657	109	50
SIPC	1,735,634	8,029	3,274	1,728,231	8,003	3,264	7,403	26	10
SMMPA	3,502,138	7,880	8,102	3,518,087	7,968	8,154	(15,949)	(89)	(52)
SPRIL	2,616,046	2,588	1,509	2,626,524	2,599	1,509	(10,478)	(12)	0
WAPA	20,019,307	38,989	4,214	20,992,561	40,529	4,371	(973,254)	(1,540)	(156)
WEP	36,541,436	45,637	43,611	36,382,847	45,329	43,314	158,589	309	297
WPL	12,953,966	39,421	23,065	12,815,315	39,440	23,064	138,650	(19)	1
WPS	14,385,713	34,666	20,729	14,314,788	34,466	20,607	70,925	200	121
Grand Total	892,516,686	2,154,513	1,023,899	893,597,141	2,154,970	1,021,275	(1,080,455)	(457)	2,623

Appendix F Annual Summary of Emission Cost by Area

Table F-1 Annual Summary by Area – Emission Cost of 2029 BCW Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 ($M)	NOx ($M)	SO_2 ($M)	CO_2 ($M)	NOx ($M)	SO_2 ($M)	ΔCO_2 ($M)	ΔNOx ($M)	ΔSO_2 ($M)
AEP	0.00	65.33	15.93	0.00	65.11	15.86	0.00	0.22	0.07
ALWFT	0.00	14.90	5.31	0.00	15.24	5.44	0.00	(0.34)	(0.13)
AM_IL	0.00	37.65	9.89	0.00	37.05	9.83	0.00	0.60	0.06
AMRNUE	0.00	37.27	0.00	0.00	37.28	0.00	0.00	(0.01)	0.00
CIN	0.00	38.64	10.28	0.00	38.43	10.23	0.00	0.21	0.05
DETED	0.00	61.53	0.00	0.00	61.07	0.00	0.00	0.46	0.00
DP&L	0.00	7.65	2.30	0.00	7.64	2.29	0.00	0.01	0.01
DPC	0.00	5.00	1.69	0.00	5.73	1.97	0.00	(0.73)	(0.28)
FEOHIO	0.00	46.04	13.71	0.00	45.47	13.61	0.00	0.57	0.10
GRE	0.00	2.07	0.24	0.00	2.20	0.29	0.00	(0.13)	(0.05)
HEC	0.00	3.96	0.98	0.00	3.95	0.97	0.00	0.01	0.01
IP&L	0.00	14.55	3.46	0.00	14.65	3.47	0.00	(0.10)	(0.01)
LES	0.00	1.14	0.00	0.00	1.24	0.00	0.00	(0.10)	0.00
MDU	0.00	1.98	0.00	0.00	2.00	0.00	0.00	(0.02)	0.00
MGE	0.00	2.83	0.97	0.00	2.82	0.97	0.00	0.01	0.00
MICHIGAN	0.00	28.95	9.85	0.00	28.71	9.78	0.00	0.24	0.07
MIDAM	0.00	20.37	9.34	0.00	19.26	8.72	0.00	1.11	0.62
MIPU	0.00	5.37	1.93	0.00	5.36	1.92	0.00	0.01	0.01
MPL	0.00	6.54	3.57	0.00	6.75	3.62	0.00	(0.21)	(0.05)
MPW	0.00	0.62	0.50	0.00	0.63	0.51	0.00	(0.01)	(0.01)
NIPSCO	0.00	12.13	2.91	0.00	11.98	2.89	0.00	0.15	0.02
NPPD	0.00	0.14	0.25	0.00	0.15	0.25	0.00	(0.01)	0.00
NSP	0.00	11.57	6.68	0.00	12.12	6.84	0.00	(0.55)	(0.16)
OPPD	0.00	10.52	0.00	0.00	10.07	0.00	0.00	0.45	0.00
OTP	0.00	0.50	0.20	0.00	0.53	0.20	0.00	(0.03)	0.00
PJMNIC	0.00	29.24	9.46	0.00	29.02	9.38	0.00	0.22	0.08
SIGE	0.00	19.65	3.12	0.00	19.62	3.11	0.00	0.03	0.01
SIPC	0.00	2.16	0.51	0.00	2.16	0.51	0.00	0.00	0.00
SMMPA	0.00	1.98	1.14	0.00	2.10	1.18	0.00	(0.12)	(0.04)
SPRIL	0.00	0.67	0.29	0.00	0.68	0.28	0.00	(0.01)	0.01
WAPA	0.00	1.03	0.45	0.00	1.01	0.41	0.00	0.02	0.04
WEP	0.00	11.79	6.66	0.00	11.75	6.65	0.00	0.04	0.01
WPL	0.00	10.06	3.58	0.00	10.29	3.73	0.00	(0.23)	(0.15)
WPS	0.00	8.64	3.07	0.00	8.67	3.10	0.00	(0.03)	(0.03)
Grand Total	0.00	522.47	128.27	0.00	520.74	128.01	0.00	1.73	0.26

Table F-2 Annual Summary by Area – Emission Cost of 2029 HGF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 ($M)	NOx ($M)	SO_2 ($M)	CO_2 ($M)	NOx ($M)	SO_2 ($M)	ΔCO_2 ($M)	ΔNOx ($M)	ΔSO_2 ($M)
AEP	0.00	65.33	15.92	0.00	65.11	15.85	0.00	0.22	0.07
ALWFT	0.00	14.91	5.31	0.00	15.24	5.44	0.00	(0.33)	(0.13)
AM_IL	0.00	37.66	9.89	0.00	37.05	9.82	0.00	0.61	0.07
AMRNUE	0.00	37.27	0.00	0.00	37.28	0.00	0.00	(0.01)	0.00
CIN	0.00	38.63	10.26	0.00	38.43	10.22	0.00	0.20	0.04
DETED	0.00	61.53	0.00	0.00	61.07	0.00	0.00	0.46	0.00
DP&L	0.00	7.65	2.30	0.00	7.64	2.29	0.00	0.01	0.01
DPC	0.00	5.00	1.69	0.00	5.73	1.97	0.00	(0.73)	(0.28)
FEOHIO	0.00	46.03	13.71	0.00	45.47	13.61	0.00	0.56	0.10
GRE	0.00	2.07	0.24	0.00	2.20	0.29	0.00	(0.13)	(0.05)
HEC	0.00	3.96	0.99	0.00	3.95	0.98	0.00	0.01	0.01
IP&L	0.00	14.55	3.46	0.00	14.65	3.47	0.00	(0.10)	(0.01)
LES	0.00	1.14	0.00	0.00	1.24	0.00	0.00	(0.10)	0.00
MDU	0.00	1.99	0.00	0.00	2.00	0.00	0.00	(0.01)	0.00
MGE	0.00	2.83	0.97	0.00	2.82	0.97	0.00	0.01	0.00
MICHIGAN	0.00	28.95	9.85	0.00	28.71	9.78	0.00	0.24	0.07
MIDAM	0.00	20.38	9.35	0.00	19.26	8.73	0.00	1.12	0.62
MIPU	0.00	5.37	1.93	0.00	5.36	1.92	0.00	0.01	0.01
MPL	0.00	6.54	3.57	0.00	6.75	3.63	0.00	(0.21)	(0.06)
MPW	0.00	0.62	0.50	0.00	0.63	0.51	0.00	(0.01)	(0.01)
NIPSCO	0.00	12.13	2.91	0.00	11.98	2.89	0.00	0.15	0.02
NPPD	0.00	0.14	0.25	0.00	0.15	0.25	0.00	(0.01)	0.00
NSP	0.00	11.57	6.69	0.00	12.12	6.85	0.00	(0.55)	(0.16)
OPPD	0.00	10.52	0.00	0.00	10.07	0.00	0.00	0.45	0.00
OTP	0.00	0.50	0.20	0.00	0.54	0.21	0.00	(0.04)	(0.01)
PJMNIC	0.00	29.24	9.45	0.00	29.03	9.36	0.00	0.21	0.09
SIGE	0.00	19.63	3.11	0.00	19.61	3.11	0.00	0.02	0.00
SIPC	0.00	2.16	0.51	0.00	2.15	0.51	0.00	0.01	0.00
SMMPA	0.00	1.98	1.14	0.00	2.10	1.18	0.00	(0.12)	(0.04)
SPRIL	0.00	0.67	0.29	0.00	0.68	0.28	0.00	(0.01)	0.01
WAPA	0.00	1.03	0.46	0.00	1.01	0.42	0.00	0.02	0.04
WEP	0.00	11.80	6.66	0.00	11.75	6.65	0.00	0.05	0.01
WPL	0.00	10.06	3.58	0.00	10.29	3.72	0.00	(0.23)	(0.14)
WPS	0.00	8.65	3.07	0.00	8.67	3.09	0.00	(0.02)	(0.02)
Grand Total	0.00	522.49	128.26	0.00	520.74	128.00	0.00	1.75	0.26

Table F-3 Annual Summary by Area – Emission Cost of 2029 LCF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 ($M)	NOx ($M)	SO_2 ($M)	CO_2 ($M)	NOx ($M)	SO_2 ($M)	ΔCO_2 ($M)	ΔNOx ($M)	ΔSO_2 ($M)
AEP	0.00	64.77	15.82	0.00	64.64	15.75	0.00	0.13	0.07
ALWFT	0.00	10.21	3.27	0.00	10.54	3.33	0.00	(0.33)	(0.06)
AM_IL	0.00	37.24	9.81	0.00	36.62	9.72	0.00	0.62	0.09
AMRNUE	0.00	36.77	0.00	0.00	36.75	0.00	0.00	0.02	0.00
CIN	0.00	38.68	10.25	0.00	38.47	10.21	0.00	0.21	0.04
DETED	0.00	61.15	0.00	0.00	60.68	0.00	0.00	0.47	0.00
DP&L	0.00	7.64	2.29	0.00	7.64	2.28	0.00	0.00	0.01
DPC	0.00	4.96	1.70	0.00	5.90	2.03	0.00	(0.94)	(0.33)
FEOHIO	0.00	45.87	13.66	0.00	45.34	13.56	0.00	0.53	0.10
GRE	0.00	2.06	0.26	0.00	2.21	0.32	0.00	(0.15)	(0.06)
HEC	0.00	3.95	0.99	0.00	3.95	0.98	0.00	0.00	0.01
IP&L	0.00	14.69	3.49	0.00	14.77	3.50	0.00	(0.08)	(0.01)
LES	0.00	0.81	0.00	0.00	0.90	0.00	0.00	(0.09)	0.00
MDU	0.00	2.06	0.00	0.00	1.99	0.00	0.00	0.07	0.00
MGE	0.00	2.75	0.95	0.00	2.71	0.94	0.00	0.04	0.01
MICHIGAN	0.00	28.73	9.79	0.00	28.50	9.71	0.00	0.23	0.08
MIDAM	0.00	18.16	8.77	0.00	17.32	8.30	0.00	0.84	0.47
MIPU	0.00	5.25	1.92	0.00	5.27	1.91	0.00	(0.02)	0.01
MPL	0.00	6.11	3.33	0.00	6.22	3.37	0.00	(0.11)	(0.04)
MPW	0.00	0.15	0.20	0.00	0.16	0.21	0.00	(0.01)	(0.01)
NIPSCO	0.00	11.93	2.88	0.00	11.81	2.85	0.00	0.12	0.03
NPPD	0.00	0.14	0.23	0.00	0.15	0.25	0.00	(0.01)	(0.02)
NSP	0.00	8.58	4.72	0.00	9.17	5.13	0.00	(0.59)	(0.41)
OPPD	0.00	6.71	0.00	0.00	6.39	0.00	0.00	0.32	0.00
OTP	0.00	0.47	0.19	0.00	0.50	0.19	0.00	(0.03)	0.00
PJMNIC	0.00	28.63	9.24	0.00	28.43	9.17	0.00	0.20	0.07
SIGE	0.00	19.64	3.11	0.00	19.60	3.10	0.00	0.04	0.01
SIPC	0.00	2.14	0.50	0.00	2.13	0.50	0.00	0.01	0.00
SMMPA	0.00	1.72	0.99	0.00	1.89	1.06	0.00	(0.17)	(0.07)
SPRIL	0.00	0.67	0.28	0.00	0.67	0.28	0.00	0.00	0.00
WAPA	0.00	1.07	0.47	0.00	1.03	0.43	0.00	0.04	0.04
WEP	0.00	11.66	6.59	0.00	11.56	6.55	0.00	0.10	0.04
WPL	0.00	9.79	3.49	0.00	10.08	3.67	0.00	(0.29)	(0.18)
WPS	0.00	8.50	3.03	0.00	8.41	3.01	0.00	0.09	0.02
Grand Total	0.00	503.66	122.22	0.00	502.40	122.31	0.00	1.26	(0.09)

Table F-4 Annual Summary by Area – Emission Cost of 2029 LWF Scenario

Area	Alternative 2			Alternative 5			Alternative 2 – Alternative 5		
	CO_2 ($M)	NOx ($M)	SO_2 ($M)	CO_2 ($M)	NOx ($M)	SO_2 ($M)	ΔCO_2 ($M)	ΔNOx ($M)	ΔSO_2 ($M)
AEP	0.00	67.30	16.17	0.00	67.21	16.13	0.00	0.09	0.04
ALWFT	0.00	16.04	5.68	0.00	16.16	5.70	0.00	(0.12)	(0.02)
AM_IL	0.00	38.97	10.10	0.00	38.59	10.07	0.00	0.38	0.03
AMRNUE	0.00	37.75	0.00	0.00	37.70	0.00	0.00	0.05	0.00
CIN	0.00	38.45	10.28	0.00	38.21	10.24	0.00	0.24	0.04
DETED	0.00	62.29	0.00	0.00	62.04	0.00	0.00	0.25	0.00
DP&L	0.00	7.68	2.31	0.00	7.68	2.31	0.00	0.00	0.00
DPC	0.00	5.44	1.83	0.00	5.63	1.91	0.00	(0.19)	(0.08)
FEOHIO	0.00	46.40	13.78	0.00	45.98	13.71	0.00	0.42	0.07
GRE	0.00	2.18	0.26	0.00	2.22	0.28	0.00	(0.04)	(0.02)
HEC	0.00	3.97	0.98	0.00	3.96	0.97	0.00	0.01	0.01
IP&L	0.00	14.16	3.37	0.00	14.22	3.38	0.00	(0.06)	(0.01)
LES	0.00	1.30	0.00	0.00	1.43	0.00	0.00	(0.13)	0.00
MDU	0.00	2.15	0.00	0.00	2.21	0.00	0.00	(0.06)	0.00
MGE	0.00	3.01	1.01	0.00	2.99	1.01	0.00	0.02	0.00
MICHIGAN	0.00	29.41	9.98	0.00	29.27	9.94	0.00	0.14	0.04
MIDAM	0.00	22.81	10.21	0.00	22.48	10.01	0.00	0.33	0.20
MIPU	0.00	5.48	2.00	0.00	5.46	1.96	0.00	0.02	0.04
MPL	0.00	6.99	3.78	0.00	7.12	3.79	0.00	(0.13)	(0.01)
MPW	0.00	0.66	0.54	0.00	0.66	0.54	0.00	0.00	0.00
NIPSCO	0.00	12.62	3.00	0.00	12.55	2.99	0.00	0.07	0.01
NPPD	0.00	0.17	0.29	0.00	0.19	0.31	0.00	(0.02)	(0.02)
NSP	0.00	12.78	7.18	0.00	12.86	7.16	0.00	(0.08)	0.02
OPPD	0.00	11.83	0.00	0.00	11.61	0.00	0.00	0.22	0.00
OTP	0.00	0.55	0.21	0.00	0.57	0.21	0.00	(0.02)	0.00
PJMNIC	0.00	31.47	10.09	0.00	31.33	10.05	0.00	0.14	0.04
SIGE	0.00	19.61	3.11	0.00	19.58	3.10	0.00	0.03	0.01
SIPC	0.00	2.17	0.52	0.00	2.17	0.51	0.00	0.00	0.01
SMMPA	0.00	2.13	1.21	0.00	2.15	1.21	0.00	(0.02)	0.00
SPRIL	0.00	0.70	0.30	0.00	0.70	0.29	0.00	0.00	0.01
WAPA	0.00	1.21	0.53	0.00	1.25	0.52	0.00	(0.04)	0.01
WEP	0.00	12.31	6.88	0.00	12.23	6.85	0.00	0.08	0.03
WPL	0.00	10.63	3.75	0.00	10.63	3.75	0.00	0.00	0.00
WPS	0.00	9.04	3.19	0.00	8.99	3.18	0.00	0.05	0.01
Grand Total	0.00	539.66	132.54	0.00	538.03	132.08	0.00	1.63	0.46

Appendix G Non-Wind Proxy Generation

Table G-1 Non Wind Proxy Generation within Study Area

Name	Category	Area	Maximum Capacity (MW)
RRF PJM CC:23	Combined Cycle	AEP I&M	600
RRF PJM CC:44	Combined Cycle	AEP I&M	600
RRF PJM CC:26	Combined Cycle	AEP Ohio	600
RRF PJM CC:7	Combined Cycle	AEP Ohio	600
RRF PJM CC:8	Combined Cycle	AEP Ohio	600
RRF PJM CT:9	CT Gas	AEP Ohio	600
RRF PJM Hydro:17	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:18	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:19	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:20	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:21	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:22	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:23	Hydro (existing)	AEP Ohio	50
RRF PJM Hydro:24	Hydro (existing)	AEP Ohio	50
RRF PJM Biomass:14	ST Other	Commonwealth Edison Co.	200
RRF PJM CC:39	Combined Cycle	Commonwealth Edison Co.	600
RRF PJM CT:10	CT Gas	Commonwealth Edison Co.	600
RRF PJM CT:11	CT Gas	Commonwealth Edison Co.	600
RRF PJM Biomass:15	ST Other	Dayton Power & Light Co.	200
RRF PJM CC:43	Combined Cycle	Dayton Power & Light Co.	600
RRF MAPP Biomass:1	ST Other	WAPA Billings East (UM-East) DAKOTAS	200
RRF MAPP PV:1	PV	WAPA Billings East (UM-East) DAKOTAS	10
RRF MAPP PV:2	PV	WAPA Billings East (UM-East) DAKOTAS	10
RRF MISOC Biomass:1	ST Other	Hoosier Energy Rural Electric Coop Inc.	200
RRF MISOC Biomass:10	ST Other	AmerenCIPS	200
RRF MISOC Biomass:2	ST Other	Duke (Cinergy)	200
RRF MISOC Biomass:3	ST Other	Duke (Cinergy)	200
RRF MISOC Biomass:8	ST Other	AmerenCIPS	200
RRF MISOE Biomass:1	ST Other	FirstEnergy Ohio	200
RRF MISOE Biomass:5	ST Other	FirstEnergy Ohio	200
RRF MISOE Biomass:6	ST Other	Consumers Energy Co.	200
RRF MISOE Biomass:7	ST Other	FirstEnergy Ohio	200
RRF MISOE Biomass:8	ST Other	FirstEnergy Ohio	200
RRF MISOE Biomass:9	ST Other	Consumers Energy Co.	200
RRF MISOW Biomass:1	ST Other	Northern States Power Co.	200
RRF MISOW Biomass:2	ST Other	Madison Gas & Electric Co.	200

Name	Category	Area	Maximum Capacity (MW)
RRF MISOW Biomass:3	ST Other	WAPA Billings East (UM-East) NE & IA	200
RRF MISOW Biomass:4	ST Other	Minnesota Power Inc.	200
RRF MISOC PV:1	PV	AmerenUE	200
RRF MISOC PV:10	PV	AmerenUE	10
RRF MISOC PV:11	PV	AmerenUE	10
RRF MISOC PV:12	PV	AmerenUE	40
RRF MISOC PV:13	PV	AmerenUE	10
RRF MISOC PV:14	PV	AmerenUE	10
RRF MISOC PV:15	PV	AmerenCILCO	10
RRF MISOC PV:16	PV	AmerenCILCO	10
RRF MISOC PV:17	PV	AmerenCILCO	10
RRF MISOC PV:18	PV	AmerenCILCO	10
RRF MISOC PV:19	PV	AmerenCILCO	10
RRF MISOC PV:2	PV	AmerenUE	10
RRF MISOC PV:20	PV	AmerenCILCO	90
RRF MISOC PV:21	PV	AmerenCILCO	10
RRF MISOC PV:22	PV	AmerenCILCO	30
RRF MISOC PV:23	PV	AmerenCILCO	10
RRF MISOC PV:24	PV	AmerenCILCO	10
RRF MISOC PV:25	PV	AmerenCIPS	10
RRF MISOC PV:26	PV	AmerenCIPS	10
RRF MISOC PV:27	PV	AmerenCIPS	10
RRF MISOC PV:28	PV	AmerenCIPS	20
RRF MISOC PV:29	PV	AmerenCIPS	10
RRF MISOC PV:3	PV	AmerenUE	10
RRF MISOC PV:30	PV	AmerenCIPS	10
RRF MISOC PV:31	PV	AmerenCIPS	10
RRF MISOC PV:32	PV	AmerenCIPS	10
RRF MISOC PV:33	PV	AmerenCIPS	80
RRF MISOC PV:34	PV	AmerenCIPS	10
RRF MISOC PV:35	PV	AmerenCIPS	10
RRF MISOC PV:36	PV	AmerenCIPS	10
RRF MISOC PV:37	PV	AmerenCIPS	10
RRF MISOC PV:38	PV	AmerenCIPS	10
RRF MISOC PV:39	PV	AmerenCIPS	10
RRF MISOC PV:4	PV	AmerenUE	10
RRF MISOC PV:40	PV	AmerenCIPS	10
RRF MISOC PV:41	PV	AmerenCIPS	10
RRF MISOC PV:42	PV	AmerenCIPS	10
RRF MISOC PV:43	PV	AmerenCIPS	30
RRF MISOC PV:44	PV	AmerenCIPS	10
RRF MISOC PV:45	PV	AmerenCIPS	10

Name	Category	Area	Maximum Capacity (MW)
RRF MISOC PV:46	PV	AmerenCIPS	10
RRF MISOC PV:47	PV	AmerenCIPS	30
RRF MISOC PV:48	PV	AmerenCIPS	10
RRF MISOC PV:49	PV	AmerenCIPS	10
RRF MISOC PV:5	PV	AmerenUE	10
RRF MISOC PV:50	PV	AmerenCIPS	10
RRF MISOC PV:51	PV	AmerenCIPS	10
RRF MISOC PV:52	PV	AmerenCIPS	10
RRF MISOC PV:6	PV	AmerenUE	50
RRF MISOC PV:7	PV	AmerenUE	10
RRF MISOC PV:8	PV	AmerenUE	10
RRF MISOC PV:9	PV	AmerenUE	10
RRF MISOE PV:1	PV	Consumers Energy Co.	70
RRF MISOE PV:10	PV	FirstEnergy Ohio	10
RRF MISOE PV:11	PV	FirstEnergy Ohio	10
RRF MISOE PV:12	PV	FirstEnergy Ohio	10
RRF MISOE PV:13	PV	FirstEnergy Ohio	10
RRF MISOE PV:14	PV	FirstEnergy Ohio	10
RRF MISOE PV:15	PV	FirstEnergy Ohio	10
RRF MISOE PV:16	PV	FirstEnergy Ohio	10
RRF MISOE PV:17	PV	FirstEnergy Ohio	10
RRF MISOE PV:18	PV	FirstEnergy Ohio	10
RRF MISOE PV:19	PV	FirstEnergy Ohio	10
RRF MISOE PV:2	PV	Consumers Energy Co.	10
RRF MISOE PV:20	PV	FirstEnergy Ohio	10
RRF MISOE PV:21	PV	FirstEnergy Ohio	10
RRF MISOE PV:22	PV	FirstEnergy Ohio	20
RRF MISOE PV:23	PV	FirstEnergy Ohio	10
RRF MISOE PV:24	PV	FirstEnergy Ohio	10
RRF MISOE PV:25	PV	FirstEnergy Ohio	10
RRF MISOE PV:26	PV	FirstEnergy Ohio	10
RRF MISOE PV:27	PV	FirstEnergy Ohio	10
RRF MISOE PV:28	PV	FirstEnergy Ohio	10
RRF MISOE PV:3	PV	Consumers Energy Co.	40
RRF MISOE PV:4	PV	Consumers Energy Co.	40
RRF MISOE PV:5	PV	Consumers Energy Co.	10
RRF MISOE PV:6	PV	Consumers Energy Co.	10
RRF MISOE PV:7	PV	Consumers Energy Co.	10
RRF MISOE PV:8	PV	Consumers Energy Co.	130
RRF MISOE PV:9	PV	FirstEnergy Ohio	10
RRF MISOW PV:1	PV	FirstEnergy Ohio	200
RRF MISOW PV:10	PV	Northern States Power Co.	50

Name	Category	Area	Maximum Capacity (MW)
RRF MISOW PV:11	PV	Northern States Power Co.	10
RRF MISOW PV:12	PV	Northern States Power Co.	10
RRF MISOW PV:13	PV	Northern States Power Co.	10
RRF MISOW PV:14	PV	Northern States Power Co.	80
RRF MISOW PV:15	PV	Northern States Power Co.	10
RRF MISOW PV:16	PV	Northern States Power Co.	10
RRF MISOW PV:17	PV	Northern States Power Co.	10
RRF MISOW PV:18	PV	Northern States Power Co.	10
RRF MISOW PV:19	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:2	PV	Alliant East	30
RRF MISOW PV:20	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:21	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:22	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:23	PV	Southern Minnesota Municipal Power Agency	50
RRF MISOW PV:24	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:25	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:26	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:27	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:28	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:29	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:3	PV	Alliant East	10
RRF MISOW PV:30	PV	Southern Minnesota Municipal Power Agency	10
RRF MISOW PV:4	PV	Alliant East	10
RRF MISOW PV:5	PV	Alliant East	10
RRF MISOW PV:6	PV	Alliant East	10
RRF MISOW PV:7	PV	Alliant East	10
RRF MISOW PV:8	PV	Alliant East	10
RRF MISOW PV:9	PV	Alliant East	110
RRF MISOC Hydro:1	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:10	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:11	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:12	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:13	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:14	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:15	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:16	Hydro (existing)	AmerenCIPS	50
RRF MISOC Hydro:2	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:3	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:4	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:5	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:6	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:7	Hydro (existing)	AmerenUE	50

Name	Category	Area	Maximum Capacity (MW)
RRF MISOC Hydro:8	Hydro (existing)	AmerenUE	50
RRF MISOC Hydro:9	Hydro (existing)	AmerenCIPS	50
RRF MISOW Hydro:1	Hydro (existing)	Dairyland Power Coop.	50
RRF MISOE Biomass:2	ST Other	Consumers Energy Co.	200
RRF MISOE Biomass:3	ST Other	Consumers Energy Co.	200
RRF MISOE Biomass:4	ST Other	FirstEnergy Ohio	200
RRF MISOC CT:1	CT Gas	AmerenUE	600
RRF MISOC CT:2	CT Gas	AmerenCIPS	600
RRF MISOC CT:3	CT Gas	Duke (Cinergy)	600
RRF MISOE CT:1	CT Gas	FirstEnergy Ohio	600
RRF MISOE CT:10	CT Gas	FirstEnergy Ohio	600
RRF MISOE CT:4	CT Gas	FirstEnergy Ohio	600
RRF MISOE CT:5	CT Gas	Consumers Energy Co.	600
RRF MISOE CT:6	CT Gas	Detroit Edison Co.	600
RRF MISOE CT:7	CT Gas	Detroit Edison Co.	600
RRF MISOE CT:8	CT Gas	Detroit Edison Co.	600
RRF MISOE CT:9	CT Gas	FirstEnergy Ohio	600
RRF PJM Biomass:1	ST Other	Commonwealth Edison Co.	200
RRF PJM Biomass:13	ST Other	AEP Ohio	200
RRF PJM Biomass:2	ST Other	AEP Ohio	200
RRF PJM PV:50	PV	AEP Ohio	200
RRF PJM PV:54	PV	AEP Ohio	200
RRF PJM PV:11	PV	Commonwealth Edison Co.	200
RRF PJM PV:12	PV	Commonwealth Edison Co.	200
RRF PJM PV:14	PV	Commonwealth Edison Co.	200
RRF PJM PV:15	PV	Commonwealth Edison Co.	200
RRF PJM PV:16	PV	Commonwealth Edison Co.	200
RRF PJM PV:17	PV	Commonwealth Edison Co.	200
RRF PJM PV:19	PV	Commonwealth Edison Co.	200
RRF PJM PV:21	PV	Commonwealth Edison Co.	200
RRF PJM PV:22	PV	Commonwealth Edison Co.	200
RRF PJM PV:27	PV	Commonwealth Edison Co.	200
RRF PJM PV:30	PV	Commonwealth Edison Co.	200
RRF PJM PV:31	PV	Commonwealth Edison Co.	200
RRF PJM PV:32	PV	Commonwealth Edison Co.	200
RRF PJM PV:33	PV	Commonwealth Edison Co.	200
RRF PJM PV:34	PV	Commonwealth Edison Co.	200
RRF PJM PV:35	PV	Commonwealth Edison Co.	200
RRF PJM PV:36	PV	Commonwealth Edison Co.	200
RRF PJM PV:37	PV	Commonwealth Edison Co.	200
RRF PJM PV:38	PV	Commonwealth Edison Co.	200
RRF PJM PV:39	PV	Commonwealth Edison Co.	200

Name	Category	Area	Maximum Capacity (MW)
RRF PJM PV:40	PV	Commonwealth Edison Co.	200
RRF PJM PV:41	PV	Commonwealth Edison Co.	200
RRF PJM PV:52	PV	Commonwealth Edison Co.	200
RRF PJM PV:53	PV	Commonwealth Edison Co.	200
RRF PJM PV:9	PV	Commonwealth Edison Co.	200
RRF PJM Hydro:1	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:2	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:3	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:4	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:5	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:6	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:7	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM Hydro:8	Hydro (existing)	Commonwealth Edison Co.	50
RRF PJM CC:22	Combined Cycle	Commonwealth Edison Co.	600

Table G-2 Additional Non-wind Proxy Generation in PJM

Name	Category	Area	Maximum Capacity (MW)
RRF PJM PV:43	PV	Allegheny Energy Inc.	200
RRF PJM PV:44	PV	Allegheny Energy Inc.	200
RRF PJM PV:45	PV	Pennsylvania Electric	200
RRF PJM PV:46	PV	Dominion	200
RRF PJM PV:47	PV	Pennsylvania Electric	200
RRF PJM PV:48	PV	Allegheny Energy Inc.	200
RRF PJM PV:49	PV	Allegheny Energy Inc.	200
RRF PJM PV:51	PV	Pennsylvania Electric	200
RRF PJM PV:55	PV	Delmarva Power & Light Co.	200