
Beyond the Clean Power Plan

How the Eastern Interconnection Can
Significantly Reduce CO₂ Emissions and
Maintain Reliability

Prepared for the Union of Concerned Scientists

January 28, 2016

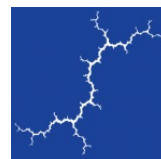
AUTHORS

Sarah Jackson

Jeremy Fisher, PhD

Bob Fagan

Wendy Ong



Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

- 1. EIPC PROCESS AND OUTCOMES OVERVIEW 1**
 - 1.1. EIPC Phase 12
 - 1.2. EIPC Phase 26
 - 1.3. Reliability and Transmission Expansion in EIPC7
 - 1.4. Scenario Total Costs10
 - 1.5. Comparing Emissions Reductions11
 - 1.6. Constraints of EIPC Modeling as Economic Prediction13

- 2. OVERVIEW OF SYNAPSE’S EXPANDED ANALYSIS OF EIPC RESULTS..... 15**
 - 2.1. Results of Synapse’s EIPC Re-Analysis.....17
 - 2.2. Changes since the EIPC Report18
 - 2.3. Co-benefits of the Carbon Reduction Scenario.....20

- 3. The EIPC AND CLEAN POWER PLAN COMPLIANCE 21**
 - 3.1. EIPC Results and Clean Power Plan Requirements in MISO22
 - 3.2. EIPC Results and Clean Power Plan Requirements in PJM26

- 4. CONCLUSIONS..... 30**

- APPENDIX A: SYNAPSE SENSITIVITIES ON EIPC SCENARIOS 31**
 - Sensitivity A: Reduced Wind..... 31
 - Sensitivity B: Improved Transmission Leads to Reduced Curtailment 32
 - Wind Capital Cost Adjustment 33
 - Present Value of Revenue Requirements for Scenarios 1 and 3 and Sensitivities..... 34

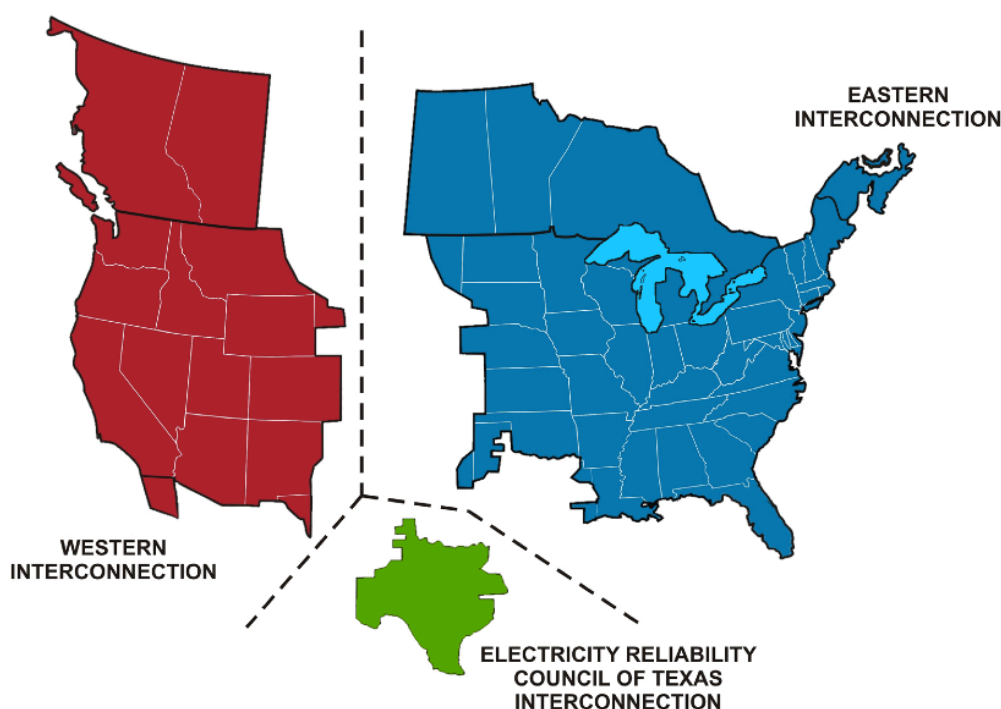
- APPENDIX B: TABLES 36**

1. EIPC PROCESS AND OUTCOMES OVERVIEW

In 2009, Congress authorized the Department of Energy (DOE) to bring together regional electric system planners to explore future transmission expansion needs in the face of a changing electric system. The Eastern Interconnection Planning Collaborative (EIPC) was born out of this effort. In 2010, the DOE awarded the EIPC a \$16 million, three-year grant to fund an assessment of electrical transmission expansion options in support of a range of possible energy futures over the next 20 years. In addition, the DOE funded, and state regulators participated in, the Eastern Interconnection States' Planning Council (EISPC) to provide input, conduct studies, and engage the states. The process also allowed for industry and public interest stakeholders to have a formal role.

The Eastern Interconnection is the largest interconnected electrical grid in the United States, connecting 39 states, the District of Columbia, and six Canadian provinces. It contains 70 percent of the U.S. population, has the largest number of utility companies, and contains six of the eight North American Electric Reliability Corporation (NERC) regions.

Figure 1. North American Electric Reliability Corporation (NERC) Interconnections



The Eastern Interconnection is the largest interconnected electrical grid in the United States, connecting 39 states, the District of Columbia, and much of Canada. It contains 70 percent of the U.S. population.

This was the first time multi-stakeholder, interregional transmission expansion planning had ever been undertaken. The utilities in the EIPC had limited experience planning on such a large scale. The largest transmission planning authorities (including Midcontinent ISO, PJM in the Ohio Valley and Mid-Atlantic

states, New York ISO, Southwest Power Pool, Southern Company, and the Tennessee Valley Authority) each conduct planning activities within their regions but rarely do these entities work together across regional boundaries. The EIPC effort required they work together on a technical level and envision power supply plans that would be shared from the Great Plains to the East Coast.

The participants in the EIPC, the EISPC, and the other stakeholders made considerable efforts to work together to develop and use inputs, assumptions, and particularly the future scenarios that defined the modeling. The stakeholders provided scenarios for future generation in Phase 1, and narrowed the number of scenarios to three for more complete study in Phase 2. The EIPC then worked to create the analysis of the generation and resulting transmission needs from this input. The EIPC produced two reports, one for each of these two main phases of the project.

1.1. EIPC Phase 1

During Phase 1 of the EIPC process, a combined grid model was created that modeled capacity expansion across the entire Eastern Interconnection. This analysis, which was conducted for the period 2015–2040, looked at eight future scenarios (Table 1) representing a range of possible policies, from business as usual to various carbon dioxide (CO₂) limits, renewable portfolio standard (RPS) requirements, end-user activities, and even a resurgence in nuclear energy.

Table 1. Summary of EIPC Phase 1 Futures

Future	Label	Definitions
1	BAU	Business as usual scenario
2	CO ₂ /N	High CO ₂ cost scenario, national implementation
3	CO ₂ /R	High CO ₂ cost scenario, regional implementation
4	EE/DR	Aggressive energy efficiency (EE), demand response (DR), and distributed generation (DG)
5	RPS/N	National renewable portfolio standard (RPS), national implementation
6	RPS/R	National RPS, regional implementation
7	NUC	Nuclear resurgence
8	CO ₂ +	High CO ₂ costs scenario with aggressive EE, DR, DG, and nationally implemented RPS

Source: ORNL, “Impacts of Demand-Side Resources on Electric Transmission Planning,” p. 12.

This set of scenarios was modeled using a zonal-based capacity expansion tool with limited temporal representation—Charles River Associates’ (CRA) NEEM model. The NEEM model¹ automatically added or removed different types of generation based on economics, generation characteristics, and multiple input assumptions, selecting the most economic (i.e., lowest-cost) generation additions and retirements

¹ NEEM is a power flow model, which is a sophisticated mathematical computer modeling tool used to examine the power flows on the electric power transmission network for specific load, resource, and transmission asset scenarios. It is the primary tool used in industry to assess the reliability of the electric power grid under many different operating circumstances. The MRN-NEEM model is a combined resource expansion and simplified dispatch/production cost analysis tool. It is sometimes referred to as just the NEEM model, reflecting the use of the electric power sector portion of the model only. The NEEM model uses a more rudimentary representation of transmission than the power flow model.

within specific regions to fulfill the requirements of each resource future. Some of these futures were defined as relying on regional cooperation on a large scale, and thus more likely to require a larger amount of transmission. The modeling produced specific expansion results for each five-year interval of the overall planning period.

While the expansion model focused on optimal electric resource *capacity* expansion, it also attempted to include transmission transfer capability expansion (between major zones only, not at a local scale). While the manner in which this was completed was not ideal,² it still resulted in transmission expansion that accounted for major scenario attributes. For example, one of the scenarios with a preference to use the highest-producing wind resources ultimately required expanded power flow capability from the Great Plains regions (where a large amount of wind was built by the model) to the more central portions of the Eastern Interconnection (where the electricity would be consumed). This result was generally expected from the wind price, availability, and performance information known at the time.

Once these eight futures were analyzed, the EIPC stakeholders discussed the results and the benefits for future efforts from examining specific scenarios in greater detail. In an open process, the stakeholders chose the three specific scenarios described in Table 2 (S1—Carbon Reduction, S2—Regionally Implemented National RPS, and S3—Business as Usual) from these runs for further study by the utility Planning Authorities in Phase 2 with more sophisticated transmission planning tools.

² The model used a "soft-constraint" methodology, wherein shadow prices between regions provided an indication of whether, and to what extent, increased transmission capability would lower overall dispatch costs. Transfer between regions was increased in proportion to the shadow price differences. This results in a relatively poor proxy for an optimal transmission expansion. See EIPC Phase 1 Report, Appendix 3, "Soft Constraint Methodology," p. 107.

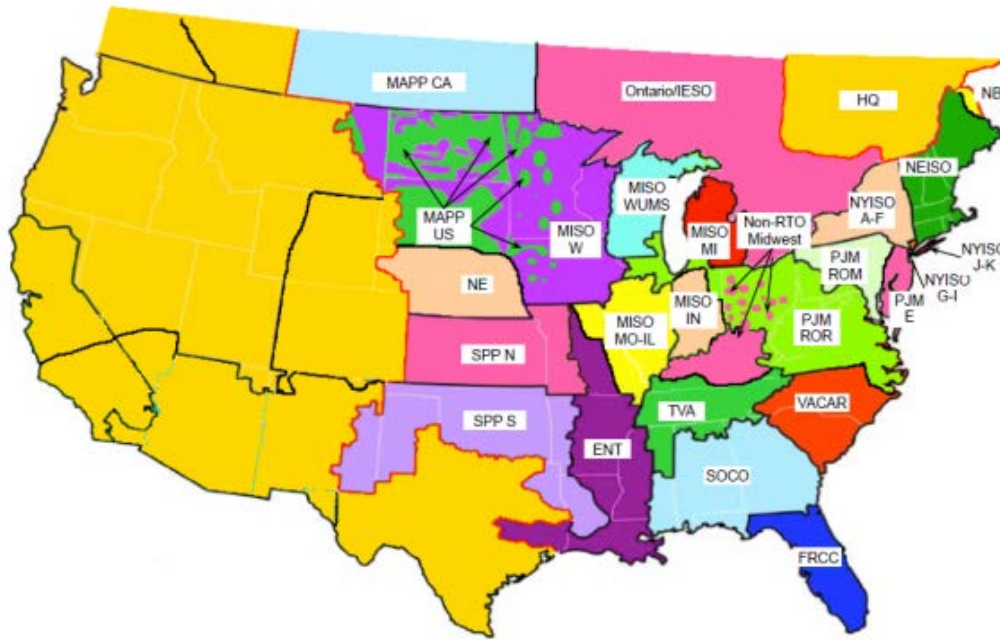
Table 2. Summary of EIPC Phase 2 Scenarios

Scenario 1 (S1)	<p>Nationally Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response (“Carbon Reduction”) Peak Demand: 565,012 MW 2030 Total Energy: 2,979 TWh CO₂: 358 million tons</p>	<p>Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050, combined with meeting 30% of the nation’s electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, and other low-carbon technologies; achieved by utilizing an interconnection-wide implementation strategy. This strategy entails extensive interregional transfers of energy to ensure availability of renewable energy from more remote location.</p>
Scenario 2 (S2)	<p>Regionally Implemented National Renewable Portfolio Standard Peak Demand: 673,108 MW 2030 Total Energy: 3,621 TWh CO₂: 1,391 million tons</p>	<p>Meet 30% of the nation’s electricity requirements from renewable resources by 2030; achieved by utilizing a regional implementation strategy. This strategy limits interregional transfers of energy, such that locally produced renewable energy is heavily utilized, but possibly at a higher cost in some circumstances.</p>
Scenario 3 (S3)	<p>Business as Usual Peak Demand: 690,492 MW 2030 Total Energy: 3,687 TWh CO₂: 1,791 million tons</p>	<p>Continuation of forecasted load growth, existing RPS requirements, and Environmental Protection Agency (EPA) regulations as proposed and understood in the summer of 2011. Includes then-existing renewable portfolio standards, no carbon regulations, and then-current load growth projections.</p>

The map in Figure 2 shows the NEEM model zonal breakdown. All regions were modeled in all the scenarios. The combinations of regions outlined in black are the “Super Regions.” The Super Regions were used in modeling the futures that called for regional implementation of policies, such as the regionally implemented RPS scenario (S2) described above.



Figure 2. NEEM Regions



Source: Adapted from ORNL, “Impacts of Demand-Side Resources on Electric Transmission Planning,” p. 11.

In Phase 1, the combined policies of aggressive efficiency, demand response, national RPS, and CO₂ price described in Oak Ridge National Laboratory’s (ORNL’s) Future #8 scenario resulted in the highest wind build-out of all the scenarios, with most of the wind concentrated in the MISO and broader SPP region (which includes Nebraska and the “MAPP-US” region, which are now integrated into the SPP RTO). This same wind build-out was then used in Phase 2 for the aggressive Carbon Reduction (S1) scenario.

Table 3. Cumulative Wind Build-out (in MW) under Future 8 (high CO₂ price, aggressive use of energy efficiency, demand response, and national RPS)

Region	2015	2020	2030
PJM	9,956	10,897	14,292
MISO	6,069	6,631	103,853
SPP (incl. NE, MAPP-US)	1,053	98,546	106,956
Other Regions	5,117	11,888	17,691
Total	22,195	127,962	242,792

Source: CRA Stakeholder Report for Future 8, Sensitivity 7, online at <http://nebula.wsimg.com/5c5c273cdb252cbd125d18acb920ac2c?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1>



1.2. EIPC Phase 2

The purpose of Phase 2 of the EIPC process was: 1) to develop and assess transmission grid expansion plans that would reliably support each of the chosen scenarios (S1—Carbon Reduction, S2—Regionally Implemented National RPS, and S3—Business as Usual); 2) to evaluate the estimated costs of overall power production and supply in each of the three scenarios for the year 2030; and 3) to estimate generation, transmission, and various “other” costs for the three scenarios.

To achieve these goals, the Phase 2 process developed transmission expansion build-outs based on the utility Planning Authorities' analysis and stakeholder input and then ran detailed production cost modeling for each of the three selected scenarios. To develop the transmission expansion needs for each of the three selected scenarios, the EIPC stakeholders used a traditional transmission planning tool (power flow modeling). The generation builds and retirements for each of the three chosen scenarios were integrated into the power flow model, then the model was used to evaluate potential future grid reliability problems using standard industry reliability tests.

The transmission planners and stakeholders participating in the EIPC process then developed transmission expansion plans designed to reliably support the different needs of each of the three futures, adding transmission upgrade solutions to the power flow model until reliability issues were resolved. The transmission expansion analysis framework consisted primarily of two components: generation interconnection requirements and transmission constraint relief. Each of the three different resource futures resulted in distinct transmission grid build-outs to support its electrical needs.

The production cost analyses were conducted using the GE MAPS hourly production cost platform, which incorporates a fairly detailed representation of the transmission system. This model simulates a security-constrained economic dispatch and security-constrained unit commitment to approximate the actual operation of the electric power grid. This production cost model was run on each of the three futures, using the generation mix identified in Phase 1 and the newly enhanced transmission systems developed in Phase 2. This modeling was conducted only for a single year: 2030.

The outcome of this process was, for each of the three scenarios, a full production cost accounting (or optimal dispatch result) of the Eastern Interconnection's 2030 operations, including emissions, prices, and all other detailed outcomes available from the GE model. However, the results, as presented, did not provide a comprehensive assessment of the relative values of the three scenarios. In particular, without further analysis of the EIPC results, there was no way to directly compare the net present value impacts over the many years of the lifetime of the transmission and other assets of the Carbon Reduction (S1) case to the assets built and operated for the Business as Usual (S3) case, due to the limited temporal information. An analysis by Synapse in 2013 (described in Section 2 below) attempted to provide the data that would allow for such a direct comparison.

1.3. Reliability and Transmission Expansion in EIPC

The EIPC process accommodated reliability concerns by explicitly utilizing load-flow modeling tools to check the viability of the expansion scenarios from the perspective of a transmission grid operator.

In Phase 1, the Planning Authorities, in conjunction with stakeholders, produced a solved load-flow model for the entire Eastern Interconnection in 2020, incorporating all planned transmission expansions. This exercise allowed for multiple transmission planning entities with extensive experience in their regions to work on an interconnection-wide solution. However, not every Phase 1 scenario was solved in this way, nor was a solution found for the multiple years associated with the Phase 1 expansion analysis—that was not an intended outcome of Phase 1. Phase 2, on the other hand, did result in such a solution for each of the chosen scenarios.

Phase 2 produced extensive transmission expansion detail for the three selected scenarios analyzed, for the year 2030 (no other year was examined for transmission expansion effects, nor was a transmission expansion timeline examined). First, interregional transmission expansion options were developed that could reliably support each scenario. Then, each of these options was further reviewed for reliability using NERC reliability criteria. Next, the cost of the energy that needed to be supplied in each scenario was analyzed by running a security-constrained economic dispatch model and, finally, estimates of the cost of generation and transmission were developed. This final step used high-level, generic cost information, such as dollar-per-mile estimates for transmission lines, rather than detailed cost estimates based on specific route selection and engineering designs.

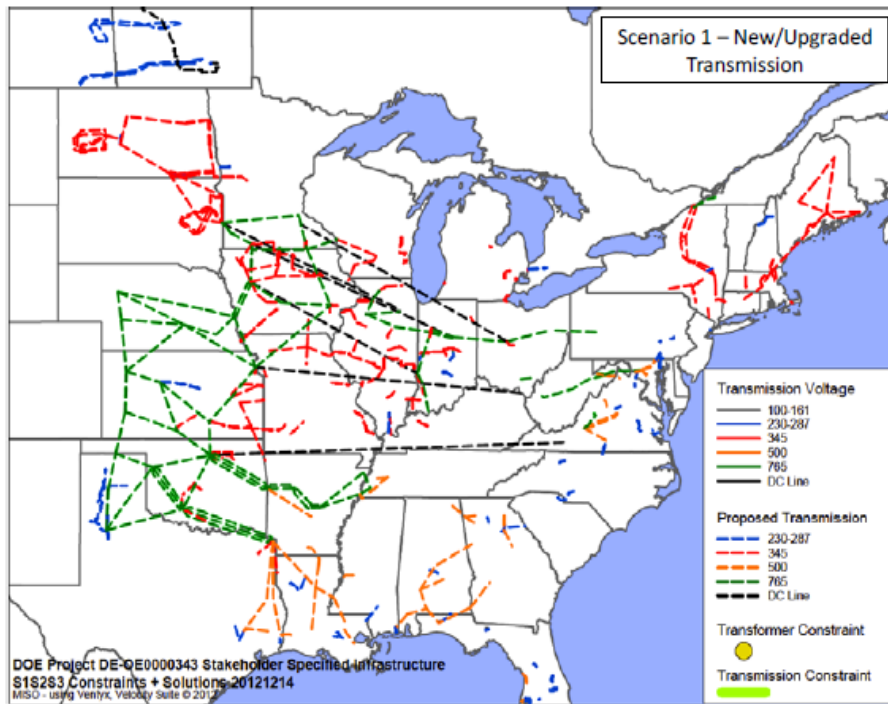
EIPC stakeholders ultimately defined a system with additional transmission line and transformer components to allow a reliability-tested solution (i.e., a solved load-flow model) for the entire interconnection and each of the three scenarios in 2030. These additions were included in the overall costs for the exercise. The transmission development was undertaken by the Transmission Options Task Force, which was a forum for stakeholders to provide input to the transmission Planning Authorities. Stakeholder input was heard by the transmission Planning Authorities, but the EIPC report and the transmission solutions therein were authored by the same transmission Planning Authorities that have responsibility for transmission planning today.

The reliability testing allowed for a secure regional power grid at voltages of 230 kV or more. The EIPC process did not include additional local studies at the lower transmission grid voltages, such as 69 kV or 115 kV.

Figure , reproduced from the final Phase 2 report, illustrates the transmission build-out envisioned for the Carbon Reduction scenario. This scenario eliminates all but 23 GW of coal capacity in the Eastern Interconnection, includes more than 215 GW of wind in the MISO, Nebraska, and SPP regions, and deploys 152 GW of demand response. As such, this scenario needed the largest transmission build-out to meet its policy objectives.



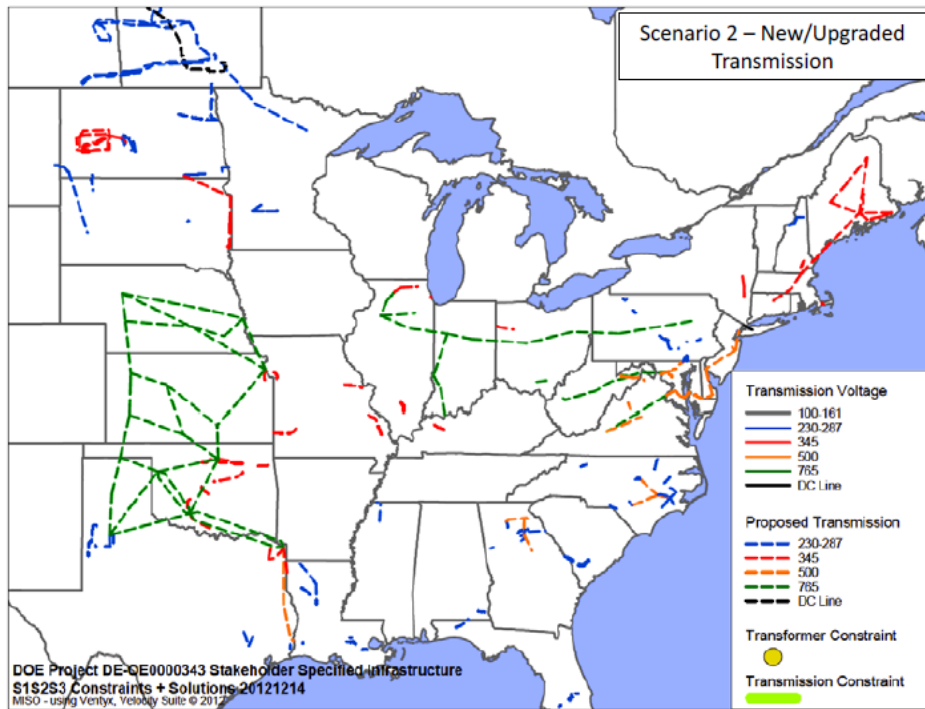
Figure 3. Scenario 1: Transmission Build-out to Achieve 42% Carbon Reductions and 30% National RPS by 2030



Source: EIPC Phase 2 Report, p. 4.

The transmission build-out required for Scenario 2 was more moderate, as a national RPS was implemented within each region (Figure 4). This scenario still shows significant amounts of wind being built in Nebraska and the SPP region. Lesser amounts of transmission, but greater amounts of wind generation, are built under this approach, which sought to use the renewable resources available in each region.

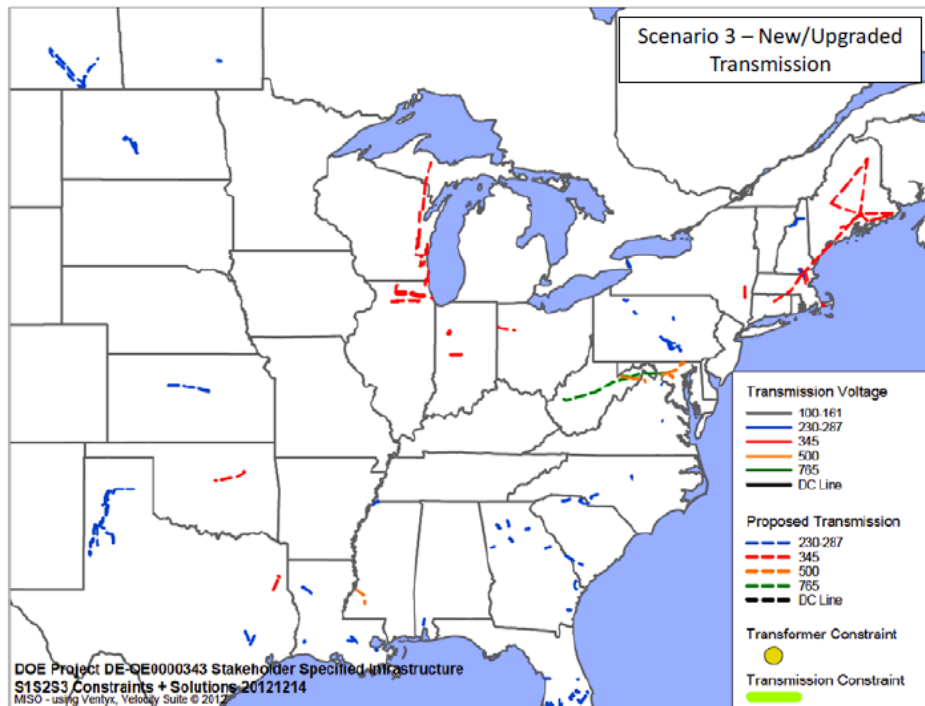
Figure 4. Scenario 2: Regionally Implemented National RPS Transmission Build-out



Source: EIPC Phase 2 Report, p. 4.

Finally, Figure 5 shows the minimal new transmission required under the Business as Usual scenario.

Figure 5. Scenario 3: Business as Usual Transmission Build-out



Source: EIPC Phase 2 Report, p. 5.

The EIPC report did not provide a cost breakdown for transmission by region; however, it did provide a mileage summary by region, which we summarize in Table 4 for the Carbon Reduction scenario.

Table 4. Transmission Expansion Mileage by Region for Scenario 1—Carbon Reduction

	Generation Interconnection	All Other Transmission	Total Mileage	Share
MISO (incl. Entergy and EIPC region share)	4,365	8,277	12,642	38%
SPP (incl. NE, MAPP-US, and EIPC region share)	4,729	3,445	8,173	25%
PJM (incl. EIPC region share)	1,279	4,277	5,556	17%
<i>Subtotal</i>	<i>10,373</i>	<i>15,998</i>	<i>26,371</i>	<i>79%</i>
Other Regions	3,265	3,590	6,856	21%
Total	13,638	19,588	33,227	100%

Note: MAPP-US and Nebraska transmission is included in SPP based on existing and planned integration of those NEEM regions into SPP. This summary excludes consideration of transformation and reactive support resources that appear in the source table. Source: EIPC Transmission Options Task Force, spreadsheet of additions, August 1, 2012. Online at <http://www.eipconline.com/modeling-results-1.html>

As seen in Figure 3 and Table 4, the majority of the transmission line build-out requirements in the Carbon Reduction scenario were in the MISO and SPP regions; a smaller amount was needed in the PJM region and the rest of the Eastern Interconnection.³

1.4. Scenario Total Costs

The EIPC Phase 1 report contained a summary of capacity expansion costs and NEEM-modeled production costs for each of the scenarios modeled at five-year intervals from 2015 through 2040. However, the Phase 1 process outcomes were used primarily to allow for scenario selection for the more temporally and spatially detailed Phase 2 modeling and cost accounting process.

The EIPC Phase 2 report contained a more extensive cost summary for generation expansion, energy efficiency investment, transmission investment, carbon "costs," and production costs for 2030. However, its provision of overall scenario cost information for the period 2015–2040 was quite limited. It only provided a single-year snapshot of production costs (i.e., operations and maintenance, or O&M) for 2030 and a summary of cumulative investment costs for capacity and transmission expansion. It did not provide for any form of cost-benefit analysis that would take the temporal dimensions of the expansion plans for each scenario into account. Table 5, from the EIPC Phase 2 report, shows the costs included in the report.

³ Online at www.eipconline.com/uploads/20120801_Scenario_Solutions_EIPC.xlsx.

Table 5. Cost Summary from the EIPC Phase 2 Report (Part 1)

2030 O&M Costs - (\$2010 Billions)			
Costs	Scenario 1: Combined Policy	Scenario 2: RPS Implemented Regionally	Scenario 3: Business as Usual
Production Costs - Fuel	\$ 40.8	\$ 73.8	\$ 85.1
Production Costs - Variable O&M	\$ 6.4	\$ 15.5	\$ 18.4
CO2 Costs	\$ 45.3	\$ 0.1	\$ 0.2
Policy Driven Energy Efficiency	\$ 8.9	\$ 1.5	\$ 1.5
CO2 Price Driven Energy Efficiency	\$ 10.0	\$ -	\$ -
Demand Response O&M	\$ 0.6	\$ 0.3	\$ 0.3
Variable Resource Integration	\$ 2.9	\$ 2.5	\$ 1.0
Fixed O&M	\$ 34.7	\$ 52.1	\$ 48.1
Total O&M Costs	\$ 149.6	\$ 145.9	\$ 154.5
Total O&M Costs without CO2	\$ 104.3	\$ 145.7	\$ 154.4
Overnight Capital Costs for Capital through 2030 (\$2010 Billions)			
Costs	Scenario 1	Scenario 2	Scenario 3
Transmission - Generation Interconnection	\$ 49.6	\$ 54.3	\$ 7.3
Transmission - Constraint Relief	\$ 48.4	\$ 13.0	\$ 7.9
Transmission - Voltage Support	\$ 0.5	\$ 0.1	\$ 0.2
Generation	\$ 868.1	\$ 679.4	\$ 242.3
Nuclear Upgrades	\$ 4.9	\$ 4.9	\$ 4.9
Pollution Retrofit Costs	\$ 6.8	\$ 20.2	\$ 22.0
Distributed Generation	\$ -	\$ -	\$ -
Total Capital Costs	\$ 978.2	\$ 771.9	\$ 284.6

Source: EIPC Phase 2 Report, p. 6.

The lower portion of Table 5 shows that total transmission costs for the entire interconnection were roughly \$100 billion, split almost equally between what is characterized as "generation interconnection" and "constraint relief." The portions of these total costs in the MISO and PJM regions combined, based on inspection of Figure and shares of mileage shown in Table 4, appear to be on the order of tens of billions of dollars of total investment. The data summarized in Table 4 did not contain a mapping of cost information.

As we mentioned above, the EIPC cost results, as presented, do not facilitate comparison of the *value* of each of the three scenarios over time. Our 2013 analysis (summarized in Section 2) provided the data to allow a direct comparison of the net present value impacts of the Carbon Reduction (S1) scenario with the Business as Usual (S3) scenario.

1.5. Comparing Emissions Reductions

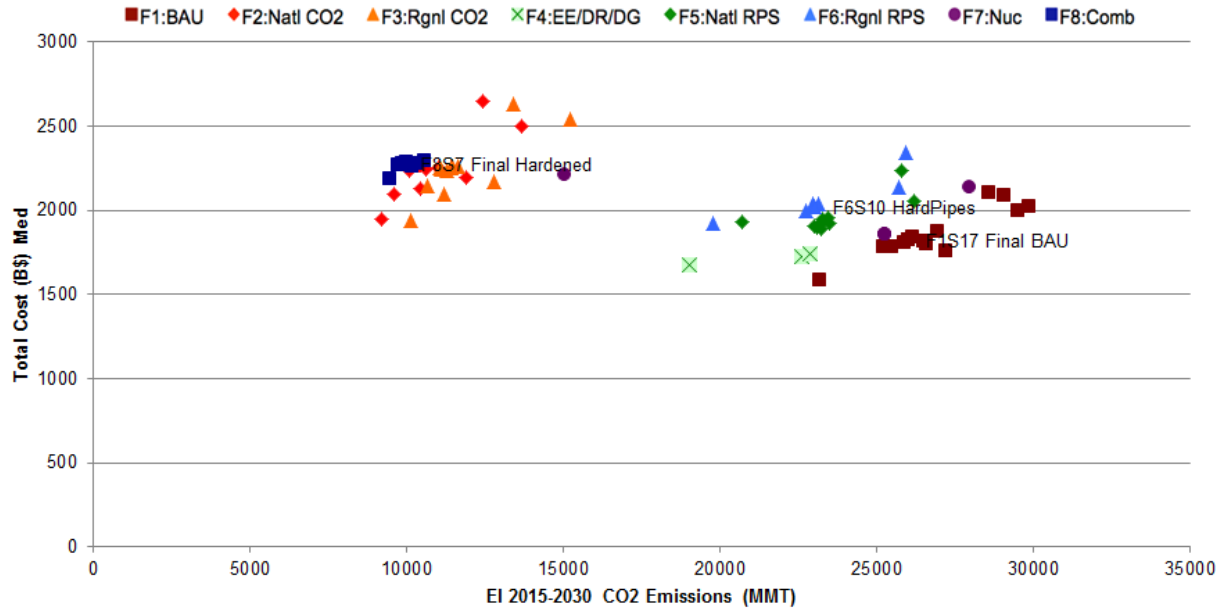
The opportunity to use the EIPC study to examine CO₂ reductions has been overlooked. The scale of the CO₂ reductions in the electric power sector set out in the results are 80 percent in 2030 compared with the Business as Usual scenario. Table 2, above, reports CO₂ emissions of 358 million tons compared with

1,792 million tons for the year 2030. This section explains how to find these results in the original EIPC reports.

The EIPC effort was not created or driven by an obligation to reduce emissions from the electric power sector, yet the data can prove useful in evaluating not only the feasibility and cost of several different potential policy approaches, but also the level of CO₂ reduction achieved in each scenario. This information was not widely (or well) reported in the final EIPC reports; however, a significant amount of data was developed to support such an analysis.

Each of the Phase 1 and Phase 2 processes produced outcomes that included an estimate of CO₂ emissions across the Eastern Interconnection, as well as nitrogen oxide (NO_x) and sulfur dioxide (SO₂) emissions, per the modeling tools used. For Phase 1, emissions results are available for each of the six single-year modeling runs (2015, 2020, 2025, 2030, 2035, and 2040). The EIPC provided little narration and the graphs depicting the results were difficult to read. For example, Figure 6 shows one illustration of the carbon emissions reporting contained in the EIPC documents. While this depiction shows cumulative (2015–2030 only) carbon emissions differences among the eight Phase 1 scenarios and sensitivities, and can be used to understand broad patterns of emissions results across scenarios, it does not present a coherent picture of the relative cost of emissions reductions, changing patterns over time for those reductions, or a comparative cost-benefit analysis across scenarios.

Figure 6. Phase 1 EIPC Summary of Cumulative CO₂ Emissions vs. Total Cost, 2015–2030



Source: EIPC Phase 1, online at www.eipconline.com/uploads/Comparisons_11-8-2011.xlsx, "ClusterGraph" tab.

Next, in Table 6 the EIPC shows the final Phase 2 reporting for CO₂ emissions (and other metrics) for the final three scenarios studied, for a single year (2030). As we note in the economic analysis, when the EIPC presents values for only a single year, the cumulative impacts of a policy and investment decision are obscured and understated, especially when you consider that the lifetimes of the resources and

transmission expansion options are more than 20 years and the impacts even longer-lasting. In the sections below, we have provided economic analysis of the cumulative savings and time value of the capital expenditures to better reflect the 20+ year length of these decisions. Note that Table 6, as presented in the EIPC report, does not indicate that these values are only for a single year (as presented in the original report).

Table 6. EIPC Phase 2 Report Tabulation of Cost, Emissions, and Energy for 2030

	Scenario 1 Base - Combined Policies	Scenario 2 Base - RPS Implemented Regionally	Scenario 3 Base - Business as Usual
Annual Production Costs (\$M)			
Fuel	40,802	73,789	85,057
Variable O&M	6,430	15,502	18,411
Total Production Costs (\$M)	47,231	89,291	103,469
CO2 Costs (\$M)	45,340	126	154
Total w/CO2	92,571	89,416	103,622
Emissions (short tons)			
SO2 (000)	93	873	1,122
NOx (000)	21	1,300	1,771
CO2 (millions)	358	1,391	1,792
Peak Demand (MW)	565,012	673,108	690,492
Energy (TWh)	2,979	3,621	3,687

Note: "CO₂ Costs" does not include recirculation of CO₂ revenue back into the economy.

Source: EIPC Phase 2 Report, Table ES-2.

The incomplete discussion of the emissions reductions in the EIPC report made that report, by itself, significantly less useful to decision makers. No time trajectory of CO₂ reduction (by scenario) was presented. There was no discussion of the economic implications of recycling carbon "cost" revenues back into the economy. The report made no attempt to place any of the carbon emissions results into any economic context whatsoever. This presents an opportunity to revisit and review these results now, with states engaged on CO₂ reduction planning as part of their compliance with the new Clean Power Plan.

1.6. Constraints of EIPC Modeling as Economic Prediction

The EIPC effort demonstrated the challenges found in any effort to model complex systems changing over time. The DOE's objective in commissioning this effort was to "support development of grid capabilities in the interconnection by preparing analyses of transmission requirements under a range of alternative futures and develop interconnection-wide transmission expansion plans."⁴ The comparison of transmission scenarios should be understood as broadly indicative, providing examples of how an adequate grid expansion could be designed, with relative costs. Here we provide some reminders that

⁴ EIPC Phase 1 Report, p. vii.

the original effort used a range of values for key variables,⁵ as well as some limits for optimizing the design and construction of future infrastructure.

Transmission Results Not Optimized for Lowest Cost

Phase 1 of the EIPC modeling framework did not optimize the amounts and location for required transmission, in concert with considerations of supply and demand. The lack of co-optimization between transmission and generation solutions was a centrally critical drawback stemming from the model construct, as the trade-offs between local resources and more remote (but less expensive) resources needing more transmission could not be made in an analytically rigorous manner. Thus, the ultimate transmission build-out seen in the Phase 2 Carbon Reduction scenario is likely not economically optimal (i.e., you could attain the same results with less transmission, or even greater reductions and lower fossil fuel use using the same transmission).

Results Do Not Address Lower Voltage Needs

Opportunities, expenses, and benefits associated with upgrading the transmission system components with voltage ratings lower than 200 KV were not included in the study. An unknown number of lower-voltage system upgrades will be needed for each of the scenarios, and the cost of these is not included in the results.

In addition, Phase 2 of the EIPC modeling framework used a fixed transmission build-out that did not address the benefits that a relaxation of lower-voltage constraints would have had on wind curtailment issues. Wind curtailment was severe—more than 25 percent of the potential energy—in a few critical regions in MISO and Nebraska, and was still extreme (15 percent) in the large SPP region in Scenario 1. This result indicated that an iterative approach to the analysis was required to prevent uneconomic curtailment.

Costs of Key Variables (Gas and Wind) Do Not Reflect Current Information

Forecasts are always subject to change as information for key variables is updated. The EIPC process used sensitivities to explore wide ranges of values for some key inputs. However, the Phase 2 EIPC reports and appendices did not dedicate much space to discussing cost comparisons found with these sensitivities. This report does not re-run the analyses, but does highlight important changes related to renewable energy costs that have occurred since the EIPC report was written. Wind turbine productivity has increased, providing lower energy costs and greater production. The latter change affects the role wind deployment would contribute to reserve margins (i.e., capacity crediting) and limits on regional

⁵ The EIPC examined sensitivity cases with 2011–2030 growth rates ranging from -22% to +41%, installed coal capacity in 2030 ranging from 12 GW to 267 GW, installed renewable capacity in 2030 ranging from 104 GW to 467 GW, and average gas costs ranging from \$2.61/MMBtu to \$10.23/MMBtu.

penetration, which were relatively conservative in the EIPC modeling. Wind capacity capital costs, in particular, are addressed in the next section and in Appendix A. More work could be done with a review of the EIPC inputs and a recalculation of results using updated values for renewable energy costs and performance, as well as for other key factors, such as natural gas prices, which have fallen dramatically since the EIPC report was released and would also affect the value of each scenario.

2. OVERVIEW OF SYNAPSE'S EXPANDED ANALYSIS OF EIPC RESULTS

Several aspects of the EIPC's published results left readers with an incomplete picture of the work done. Described below are details of our examination of: 1) annual costs, which are then accumulated for comparison; 2) recycling carbon trading revenues back into the electric sector to consumers to offset costs; and 3) impact of lower wind installation costs. Each of these adjustments is so significant to the outcome of the EIPC study that they eliminate the difference in total system cost between the Business as Usual and Carbon Reduction scenarios.

The three-year EIPC process explored a comprehensive reduction of CO₂ emissions from the electricity sector through Scenario 1, the case combining multiple climate and clean energy policies including expansive renewable energy development and energy efficiency. While the final EIPC analyses and reports contained a wealth of detail, they did not contain comprehensive cost information that would have allowed states and stakeholders to compare the cost of the scenarios over time. Specifically, the reports reviewed spending in the scenarios in five-year increments, but did not pull together a fundamental piece of information needed to assess the scenarios: the total cost that would be incurred by ratepayers.

Investments in the electricity sector last a long time. Power plants and transmission can have 30- to 50-year lifetimes, and thus require a different form of assessment than day-to-day expenses. In long-term electricity sector planning, total costs are often assessed as the net present value (NPV) of revenue requirements (i.e., how much a scenario would cost if all costs were incurred up front). By not providing this total cost, the EIPC scenarios could not be assessed against each other. In particular, the EIPC reports could not capture the long-term value of clean energy investments. For example, wind projects built in 2020 will provide avoided emissions and fuel cost benefits over two to three decades; a review of costs in 2020 only would fail to capture the long-term benefit.

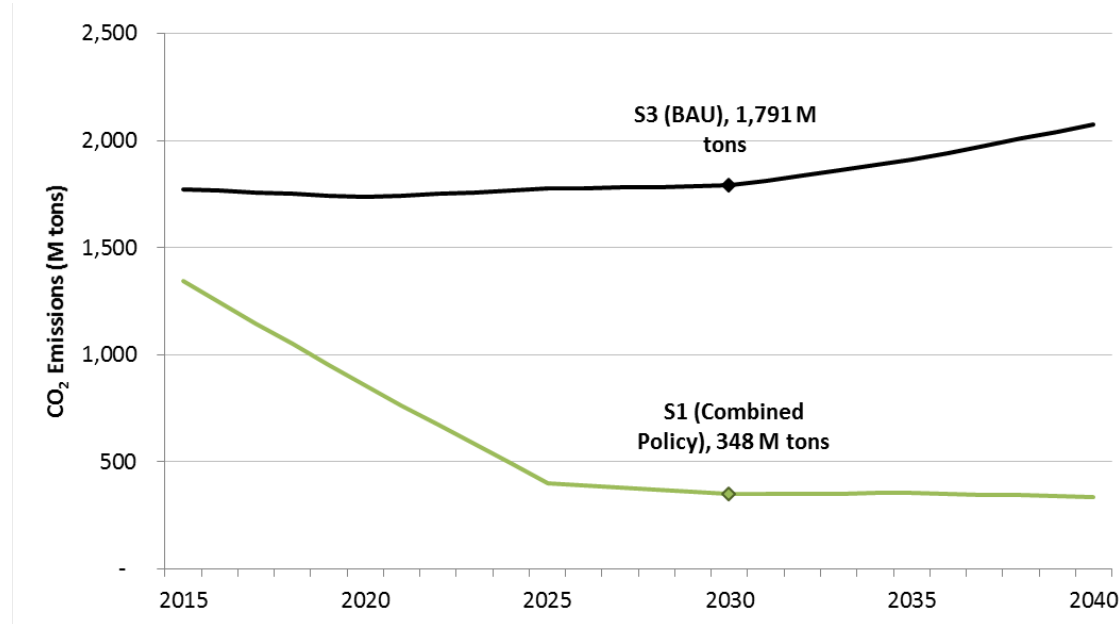
In 2013, Synapse engaged in a re-assessment of the EIPC reports, with the goal of assessing total ratepayer costs of the Business as Usual (S3) and Carbon Reduction (S1) scenarios. In a report entitled *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC*



Process,⁶ we carefully reconstructed annual costs of the scenarios, and found that the total ratepayer costs of the two dramatically different scenarios were nearly identical.

Figure shows the trajectory of CO₂ emissions reductions in EIPC Scenarios 1 and 3, with dramatic cuts through the Carbon Reduction (S1) scenario, ultimately amounting to electric sector reductions of 80 percent relative to the Business as Usual (S3) scenario by 2030. The Carbon Reduction scenario intended to reach a 50 percent economy-wide reduction in CO₂ by 2030, with the electric sector providing a deeper reduction by 2030. These targets were effectively an input to the modeling, through the use of a carbon price in the modeling.⁷ These cuts come from extensive energy efficiency programs, large-scale renewable energy build-outs throughout the Midwest, and economic retirements of fossil-fired units.

Figure 7. Carbon Emissions Profile 2015–2040, Scenarios 1 and 3



Source: Synapse, *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process: Preliminary Results*.

Our re-assessment of the EIPC results found that the significant carbon reductions from Carbon Reduction (S1) scenario could be accomplished at approximately the same total cost as the Business as Usual (S3) scenario: only 2 percent more over the analysis period, assuming that revenues from a carbon

⁶ Fagan, B., J. Fisher, and B. Biewald. 2013. *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process: Preliminary Results*. Prepared for The Sustainable FERC Project. Online at www.synapse-energy.com/project/assessing-costs-and-benefits-modeled-eipc-scenarios.

⁷ The use of a carbon price in the expansion modeling was the proxy vehicle by which the targeted quantity reductions would be achieved. CRA conducted analysis prior to the final runs to estimate the carbon price required in the model to achieve the reductions.

trading program are recycled back into the electric sector.⁸ The EIPC made no assumptions as to how the carbon revenues would be recirculated into the economy, and provided no overall discussion or accounting of this critical construct used in the modeling.

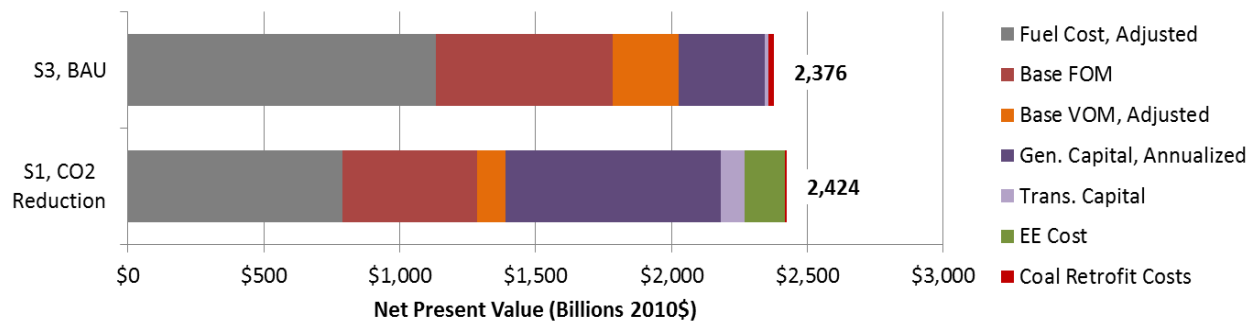
In addition, the EIPC made no attempt to annualize the streams of capital investment required, or to provide a consistent temporal framework for any analysis of the costs and benefits associated with any of the expansion scenarios. As noted previously, this means that the cost of the EIPC's scenarios could only be assessed against each other with additional analyses and adjustments; for example, the capital costs for a project expected to last 10 years have a fundamentally different value than the capital costs for a three- or four-decade project. Since the EIPC Phase 2 study evaluated only single-year costs, the analysis should have reported annualized capital costs—not total capital costs. Finally, there is limited value in comparing the cost of scenarios for a single arbitrary year. Instead, economic choices are best made in light of the NPV of all expected costs over multiple years (i.e., the all-in cost of choices made between now and a more distant future year). Our re-assessment was specifically structured to elucidate this information in the EIPC results.

2.1. Results of Synapse's EIPC Re-Analysis

Overall, we found the total cost of the Carbon Reduction (S1) scenario was about 2 percent higher than the Business as Usual (S3) scenario (\$2,424 billion vs. \$2,376 billion)—a differential likely well within the rounding errors associated with such a broad-scale, forward-looking analysis. As shown in Figure , the additional capital expenditures to build wind and energy efficiency programs incurred under the Carbon Reduction scenario are offset by significantly lower fuel and operational costs compared with Business as Usual scenario.

⁸ Recycling carbon trading revenues back into the electric sector can be accomplished through either an allocation to producers (i.e., generators) or consumers (i.e., customers or load distribution companies). The details of such an allocation scheme can matter with regards to what types of consumer or producer behaviors are incentivized. When we say that carbon trading revenues are “recycled” back into the electric sector, we are assuming these revenues are used to offset costs—either as lump sum payments or dividends to consumers, or used to lower the cost of entry for clean energy. In either case, much of the net incremental cost borne by generators (and ultimately consumers) is returned to consumers through either direct payments or lower-cost services.

Figure 8. Costs of EIPC Scenarios from Synapse Re-analysis (net present value 2015–2040)



Source: Synapse, *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process: Preliminary Results*.

The long-range costs of the two scenarios are extremely close. Despite the fact that these two scenarios have different goals and create very different systems by 2040, the NPV differences between the two scenarios are easily within a margin of error and are essentially equivalent.

The Carbon Reduction (S1) scenario spends capital to implement long-term, robust, and carbon-free infrastructure with economic benefits well beyond the 2040 analysis period shown here. By avoiding the fuel and operational costs of a large fossil fleet, the Carbon Reduction scenario reduces ratepayer costs well into the next decades.

2.2. Changes since the EIPC Report

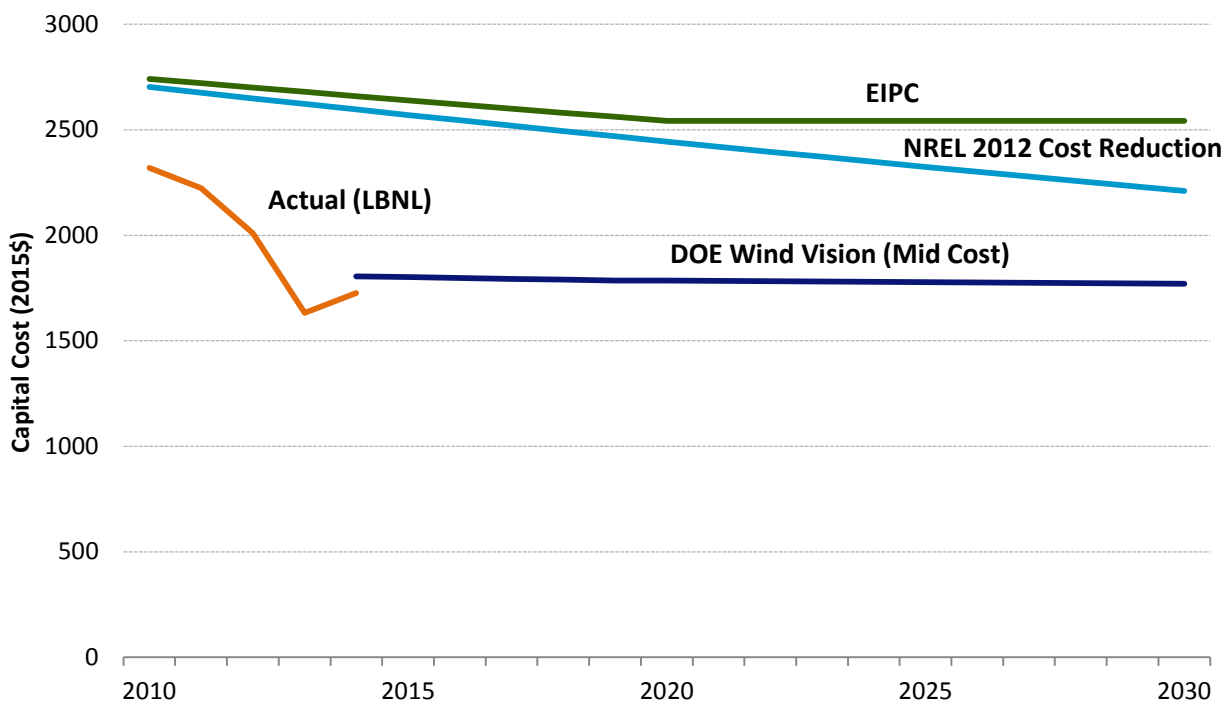
The EIPC study was based on costs and assumptions generated in 2011 and 2012. Since that time the cost of wind has fallen dramatically, solar costs have plummeted, gas prices have continued to stay depressed, and costs for coal-fired power plants have increased. We would expect all these factors would result in a different build-out and different costs. While we cannot model all these changes without re-running the EIPC models, we can roughly estimate the impact of lower wind costs.

The EIPC report assumed the capital cost of wind starts at around \$2,500/kW and falls at about 0.75 percent every year through 2025, staying steady thereafter. A report from the National Renewable Energy Laboratory (NREL) in 2012 expected costs to fall steeply through the next decades, declining 20 to 30 percent by 2030. For a sensitivity (discussed in Appendix A), we conservatively estimated in 2013 a reduction in the cost of wind of 1 percent per year, starting at the same baseline conditions as the EIPC.⁹

⁹ See, for example, Figure ES-3 in IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. Lead authors: Eric Lantz: National Renewable Energy Laboratory, Ryan Wiser: Lawrence Berkeley National Laboratory, Maureen Hand: National Renewable Energy Laboratory. Contributing authors: Athanasia Arapogianni: European Wind Energy Association, Alberto Ceña: Spanish Wind Energy Association, Emilien Simonot: Spanish Wind Energy Association, Edward James-Smith: Energy Analyses. NREL Technical Report NREL/TP-6A20-53510, May 2012. Online at www.ieawind.org/index_page_postings/WP2_task26.pdf.

However, the reported actual wind installation costs of \$1,710 in 2014 support the more recent Wind Vision report from the DOE, in which a mid-level scenario estimates wind costs already at \$1,700/kW¹⁰ and falling through the next decades¹¹ (Figure9).

Figure 9. Cost of Wind in EIPC, NREL, and DOE Wind Vision Analyses



Source: Synapse.

Assuming a lower capital cost of wind has significant impacts on the outcome of the EIPC study, as our sensitivity on wind cost (Appendix A) demonstrates. Using the more up-to-date wind costs from the DOE wind study could drop the cost of the Carbon Reduction (S1) scenario by more than \$100 billion or 4 percent.¹²

Modeling supporting the EIPC report assumed that wind would be curtailed (i.e., shed or not used) at an excessive rate. In our re-assessment, we conducted two sensitivities on the curtailment of wind, one in which the amount of wind built is reduced to allow wind to operate more economically, and another

¹⁰ See 2014 Wind Technologies Market Report. Ryan Wiser and Mark Bolinger Lawrence Berkeley National Laboratory <http://energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf>

¹¹ See DOE Wind Vision Report, Appendix H, Section H.1.3: Future Wind Plant Cost and Performance Assumptions. The Mid Cost scenario assumes 2030 overnight costs of \$1,518/kW to \$1,724/kW.

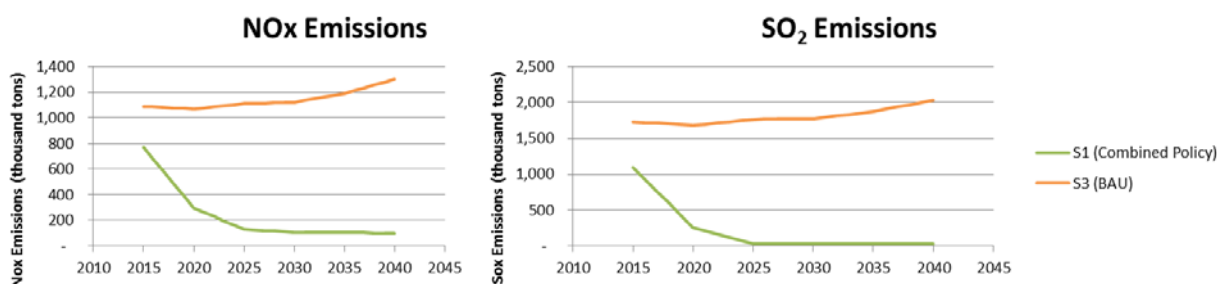
¹² An update of the EIPC and Synapse analyses using current information for all key inputs, including lower gas prices and increased regulatory costs for coal plants, would be useful for illustrating how these changes would impact the two scenarios.

that assumed improved transmission could reduce curtailment rates. These two sensitivities and their results are described in detail in Appendix A.

2.3 Co-benefits of the Carbon Reduction Scenario

In addition to carbon reduction benefits, the Carbon Reduction (S1) scenario has significant criteria emissions co-benefits. According to the EIPC modeling, in bringing on significant amounts of renewable energy and retiring almost all the coal in the Eastern Interconnection, Scenario 1 avoids more than 1 million tons of NO_x emissions—a significant ozone precursor—and more than 1.7 million tons of SO₂ emissions by 2030 (Figure 10).

Figure 10. NO_x and SO₂ Emissions in Scenario 1 (Carbon Reduction) and Scenario 3 (Business as Usual)



Source: Synapse, *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process: Preliminary Results*.

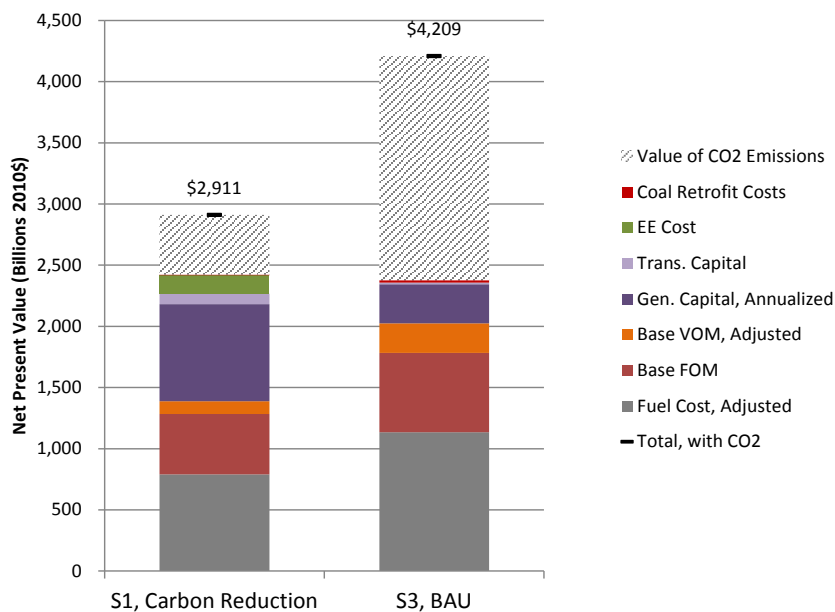
In contrast, the EPA estimates that, over the entire United States, the final Clean Power Plan will save about 0.3 million tons of NO_x and about 0.3 million tons of SO₂ by 2030.¹³

One other feature of the EIPC report is that it compared the cost of the Carbon Reduction (S1) approach to Business as Usual (S3) while including the cost of emissions in the Carbon Reduction scenario but not in the Business-as-Usual scenario. Such a comparison makes the assumption that in the Business-as-Usual world, the United States not only makes no attempt to mitigate carbon pollution, but that carbon pollution also has no value or cost. Similarly, it assumes that if U.S. policy is to mitigate carbon pollution, those mitigation costs must be incurred as a cost of emissions that are simply no longer available to the economy or in the electric sector. It is true that policy makers may enact carbon mitigation policies wherein the revenues from carbon trading are used for a wholly different purpose, and thus emissions costs simply disappear. However, reasonable market design suggests that outcomes are significantly improved if revenues are recycled back into the electric sector to reduce impacts on ratepayers and fund clean energy options. Similarly, we would not reasonably imagine that emissions of CO₂ have no

¹³ It should be noted that the EPA's estimate of the emissions reductions available from the Clean Power Plan are calibrated against expectations of emission control equipment installations known in 2014 and 2015, while the EIPC model had older data and may not have fully accounted for baseline criteria emissions reductions due to then-emerging regulations.

cost simply because we choose not to model them. In Figure 11, we show the outcome of the scenarios when the same “cost of carbon” used in the Carbon Reduction (S1) scenario is used on the carbon emissions seen in the Business as Usual (S3) scenario. In this case, the Carbon Reduction scenario has a clear advantage over Business as Usual.

Figure 11. Net Present Value of Revenue Requirements of Scenarios 1 and 3 with Consistent Valuation of CO₂ Emissions



Source: Synapse, *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process: Preliminary Results.*

Overall, the EIPC process represented a rigorous, utility-informed stakeholder process that reviewed real and tangible improvements to the electric grid to reduce environmental impacts. The dramatic effect of adding significant renewable energy was realized at effectively the same cost as a business-as-usual approach to running older plants on fossil fuels without capital investment in renewable energy and energy efficiency that would lower total costs and reduce emissions. The EIPC demonstrated that a reliable and far cleaner electricity sector was possible, at a reasonable cost and with long-term savings.

3. THE EIPC AND CLEAN POWER PLAN COMPLIANCE

Since the release of the final Clean Power Plan in August 2015, energy and environmental planners across the country have begun evaluating their options for meeting the new carbon reduction targets established by the EPA. The final Clean Power Plan seeks a 32 percent reduction in carbon emissions from the electric sector by 2030 and strongly encourages regional coordination in accomplishing these



goals. By comparing what is required under the Clean Power Plan with the scenarios modeled in the EIPC process, we identify one potential path forward that has already been vetted by the entities responsible for maintaining the reliability of our electric grid.

In this report, we focus on the PJM and MISO regional transmission organizations (RTOs), in part because these are the largest regional RTOs in the Eastern Interconnection, and because these are the areas of the country in need of some of the greatest emissions reductions under the Clean Power Plan. Further, these RTOs are where a significant portion of the new resources and transmission build-outs would occur under the EIPC scenarios. It would behoove these entities, and all entities that participated in the EIPC process, to leverage their experience in that process to help coordinate compliance with the Clean Power Plan.

Our previous report focused primarily on the cost-effectiveness of the Carbon Reduction (S1) scenario, a future selected by the EIPC stakeholders with nationally implemented federal carbon constraints and increased energy efficiency and demand response, creating a 42 percent reduction in CO₂ compared with the Business as Usual (S3) scenario.¹⁴ The Carbon Reduction scenario has an aggressive build-out of renewable energy through 2040, increasingly shifting the Eastern Interconnection away from fossil energy and toward lower emissions and less-fuel-intensive resources.

In this section, we review the renewable energy build-out and coal unit retirements found by the EIPC process, and compare the emissions reductions from the EIPC against emissions targets in the final Clean Power Plan.

3.1. EIPC Results and Clean Power Plan Requirements in MISO

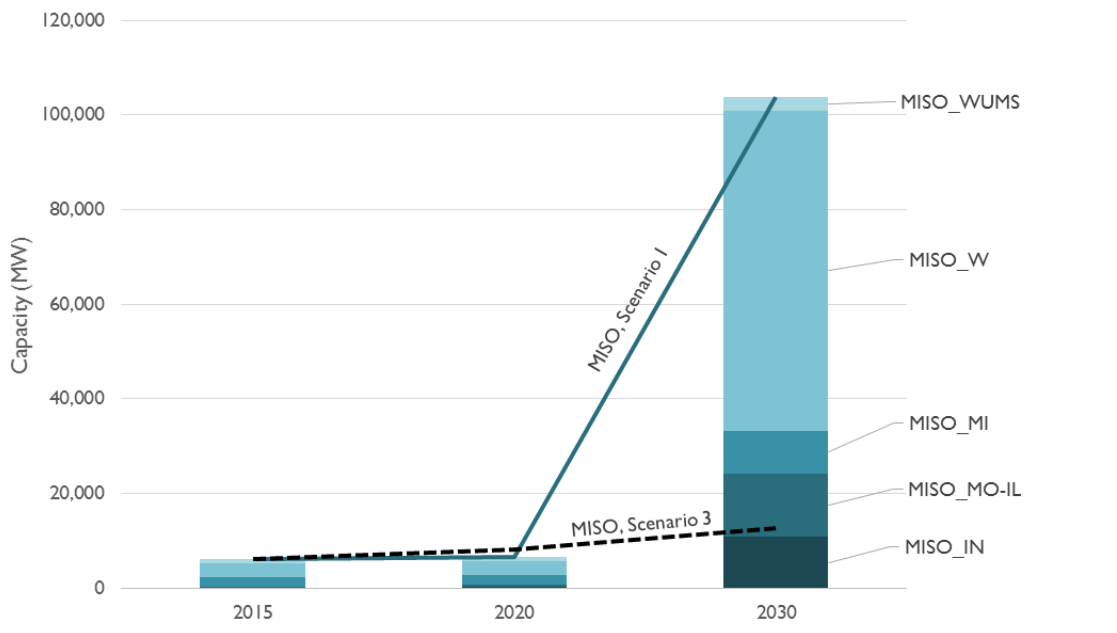
The EIPC modeling presents a case with very high levels of wind deployment and provides an indication of the transmission that would be needed in such a case. As the high levels presume exports to the east, and reduce the amount of wind that would be built in PJM, this should be understood as an example of inter-regional cooperation for carbon reduction.

In the EIPC's Carbon Reduction (S1) scenario, MISO sees rapid wind development between 2020 and 2030. By 2030, the region will build more than 100 GW of new wind capacity, the vast majority of it in

¹⁴ Our focus did not imply that some form of regionally-implemented national RPS policy (such as Scenario 2) could not also be cost-effective. Instead, as discussed in our earlier report, our analysis indicated that Scenario 2 as modeled, with restricted input assumptions and modeling limitations defined in the EIPC process, was unable to take full advantage of (and thus represent) the benefits of the broad array of high quality wind resources modeled in Scenario 1 and the full capabilities of an expanded transmission system. Thus, to be more cost effective, a national RPS policy would need to be modeled and implemented in a different manner than was modeled in Phase 2 of the EIPC process as Scenario 2. See, e.g., "30% Renewable Energy by 2030: Udall-Markey National Renewable Electricity Standard Would Boost Economy and Protect Consumers," May 15, 2015, available at <http://blog.ucsusa.org/30-percent-renewable-energy-by-2030-udall-markey-national-renewable-electricity-standard-731>.

the last 10 years of the analysis period.¹⁵ Figure 2 shows that in Scenario 1, new wind in MISO is concentrated toward the upper Midwest (called MISO_W in the analysis), covering the Dakotas, Iowa, and Minnesota. Significant new wind development is also seen in Indiana, Michigan, and into Illinois and Missouri. Overall, the new wind development in MISO in Scenario 1 exceeds the Business as Usual (S3) scenario by more than 800 percent.

Figure 12. New Wind Development in MISO in Scenarios 1 (Carbon Reduction) and 3 (Business as Usual)



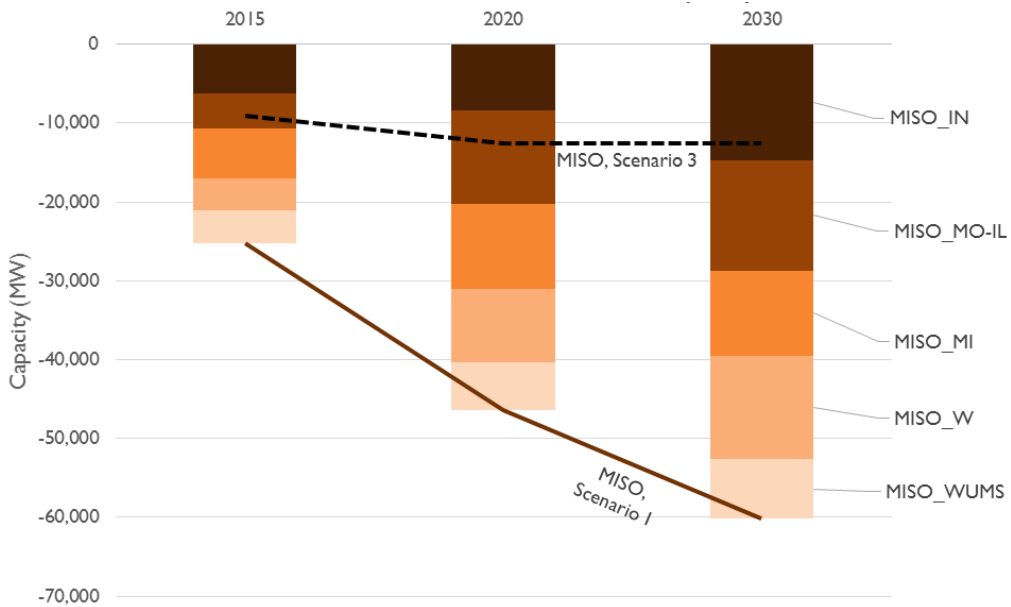
Note: The EIPC modeling was conducted during the period 2011–2012. Actual MISO wind levels in 2015 are higher than the modeled levels seen here. Source: Synapse.

The EIPC process modeled economic coal unit retirements (i.e., coal units that were more expensive to operate and maintain than to replace were assumed to be retired on an economic basis). Retirements are caused by a combination of factors including the high cost of generation relative to market energy prices, requirements for extended capital improvements, and emissions prices. In Scenario 1, the EIPC modeling forecast steadily increasing coal unit retirements, as shown in Figure. Ultimately, EIPC Scenario 1 predicted about 60 GW of coal unit retirements in MISO by 2030, or about five times more than in the Business-as-Usual scenario (S3). Since the EIPC process was completed in 2012, only between five and nine gigawatts of coal retirements in the MISO region have been announced.¹⁶

¹⁵ One hundred gigawatts equates to roughly 41 percent of MISO’s expected generation in 2030. To put this in perspective, the recent Wind Vision study released by the DOE in March 2015 found that, under a less aggressive future scenario, wind penetration levels in the MISO region could reach 38 percent of total generation by 2030.

¹⁶ Coal plant deactivation requests in the last three years total 9,272 MW, which includes 20 requests (4,810 MW) for unit suspension and 31 requests (4,460 MW) for unit retirement. See p. 77 of the 2014 MISO report on Multi-Value Projects, filed

Figure 13. Coal Unit Retirements (Cumulative) in MISO in Scenarios 1 (Carbon Reduction) and 3 (Business as Usual)



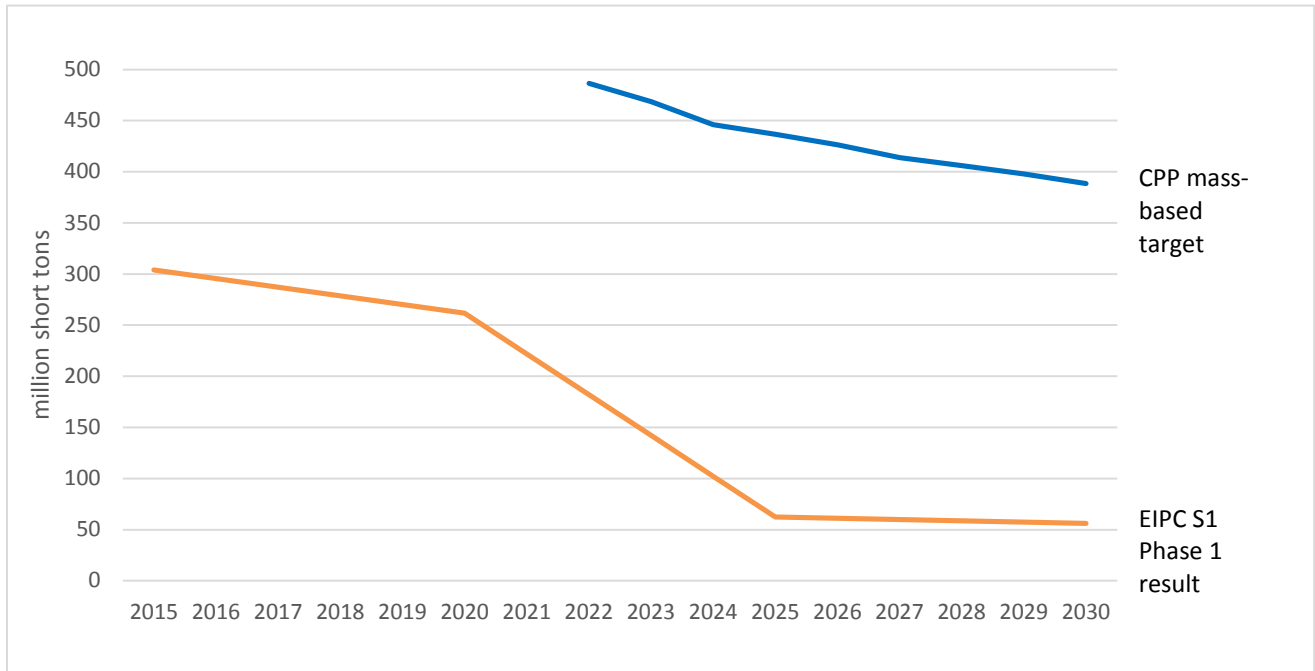
Source: Synapse.

The significant coal-fired retirements in MISO in Scenario 1 lead to deep carbon reductions in the region. According to EIPC modeling, emissions in the region drop more than 90 percent by 2025, stabilizing at about 50 million tons per year, as opposed to 500 million tons in 2015. Figure 14 compares CO₂ emissions from the EIPC process compared with the final Clean Power Plan (CPP) mass-based target for MISO states. The CPP requires MISO states to reduce mass-based emissions by about 25 percent through 2030—a significantly less stringent target than what was modeled by the EIPC.

April 30, 2015. Online at www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/FINAL%20MVP_Annual_Report%202014%20ER10-1791.pdf.



Figure 14. EIPC vs. Clean Power Plan CO₂ Emissions Targets for MISO



Source: Synapse.

While the Clean Power Plan establishes state-by-state targets for CO₂ emissions, we were able to estimate Clean Power Plan emissions targets for the PJM and MISO reliability regions, which do not adhere to state boundaries. This was done by identifying the states that fall in PJM and MISO territories, determining Clean Power Plan state mass-based targets between 2022 and 2030,¹⁷ using U.S. Energy Information Administration (EIA) 2012 individual unit information¹⁸ to assign generation in each of these states to PJM and MISO, and allocating the state’s emissions targets to each region in proportion to generation.¹⁹

¹⁷ Based on www2.epa.gov/sites/production/files/2015-08/copy_of_cpp_final_goals_and_nscomplement_summary_table_8-4_0.xlsx.

¹⁸ 2012 Form EIA 860 Schedule 2, “Plant Data,” and EIA 923 “Page 4 Generator Data.”

¹⁹ Note that some Electric Generating Units (EGUs) moved in and out of the PJM and MISO regions between the 2010 EIPC region year and 2012 due to the redrawing of reliability region boundaries. However, this caveat does not affect the overall pattern and conclusions drawn from our analysis. The analysis for MISO represents the “classic” or “northern” region of MISO, excluding the newer southern additions of Arkansas and Louisiana.

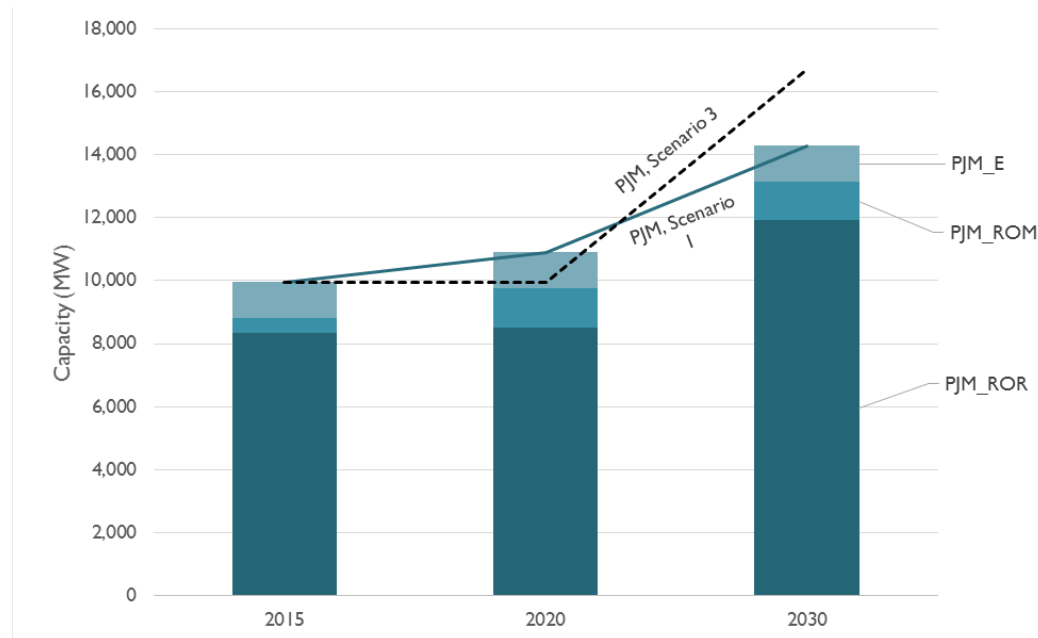
Table 7. Summary of MISO Regional Results of EIPC Business-as-Usual and Carbon Reduction Scenarios

	MISO States					
	2015		2020		2030	
	<u>Business-as-Usual</u>	<u>Carbon Reduction</u>	<u>Business-as-Usual</u>	<u>Carbon Reduction</u>	<u>Business-as-Usual</u>	<u>Carbon Reduction</u>
Coal retirements cumulative (MW)	9,049	25,274	12,522	46,404	12,522	60,182
New wind capacity cumulative (MW)	6,069	6,069	8,060	6,631	12,639	103,853
Carbon dioxide emitted (million tons)	406	304	382	262	384	56
Clean Power Plan carbon dioxide allowed (million tons in 2022 and 2030)			486	486	388	388

3.2. EIPC Results and Clean Power Plan Requirements in PJM

Wind development in PJM is far less dramatic in Scenario 1 than in MISO. Where MISO showed a more than 900 percent increase from 2015 to 2030 in Scenario 1, and a far larger wind build-out in Scenario 1 than in the Business as Usual scenario, the opposite is true in PJM. The wind build-out is slightly lower in Scenario 1 than in Business as Usual Scenario 3, although wind development increases by about 30 percent from 2020 to 2030 in Scenario 1 (Figure 215). Nonetheless, the build-out in PJM pales in comparison with the MISO build-out. As in MISO, the majority of wind development occurs in the western side of the PJM region (“PJM_ROR”), encompassing Illinois, Ohio, western Pennsylvania, and West Virginia.

Figure 15. New Wind Development in PJM in Scenarios 1 (Carbon Reduction) and 3 (Business as Usual)



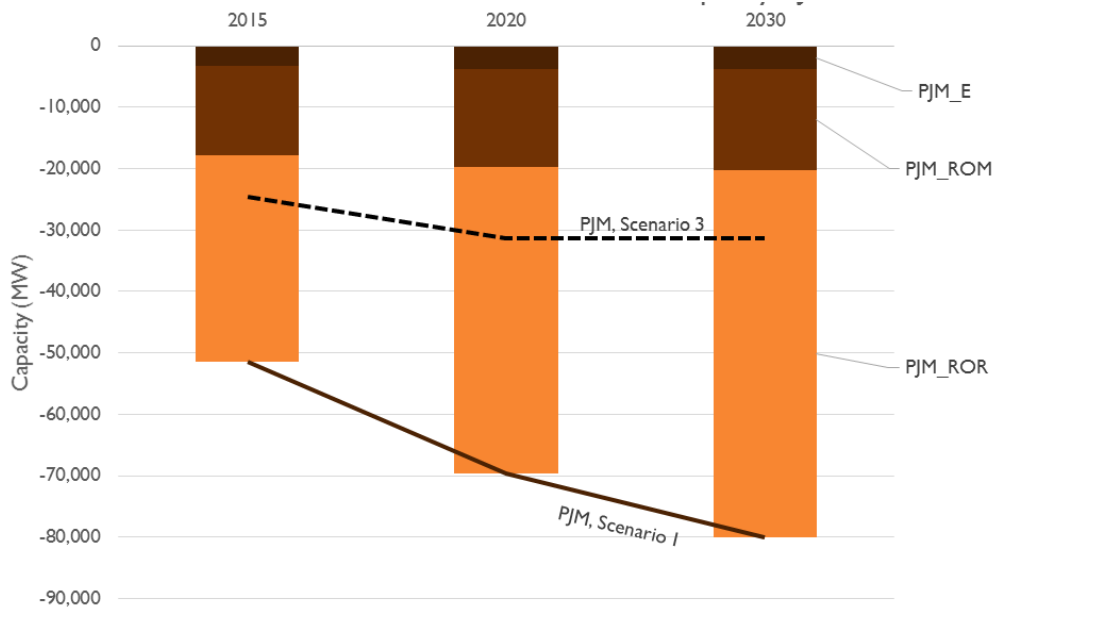
Source: Synapse.

Significant new transmission from MISO and points west into PJM allow for wind energy to displace existing coal, and coal units in PJM become non-economic rapidly in the EIPC assessment. In fact, the Carbon Reduction scenario estimated a very large block (around 50 GW) of economic coal unit retirements in 2015, primarily in western PJM states. While this degree of coal unit retirement was not actually seen in 2015, the scenario does indicate that increasing renewable energy and emissions prices quickly would affect marginal coal resources. Since 2009, 25 GW of coal retirements in the PJM region have actually been announced.²⁰

The EIPC process estimated steadily increasing retirements in Western PJM (“PJM_ROR”) through 2030, eventually reducing coal capacity by 80 GW—or about 2.5 times more than in the Business as Usual scenario (Figure 16). By comparison, in an analysis by PJM of the *proposed* Clean Power Plan, additional coal plant retirements were estimated in a range from 8 to 32 GW.

²⁰ See www.pjm.com/planning/generation-deactivation/gd-summaries.aspx.

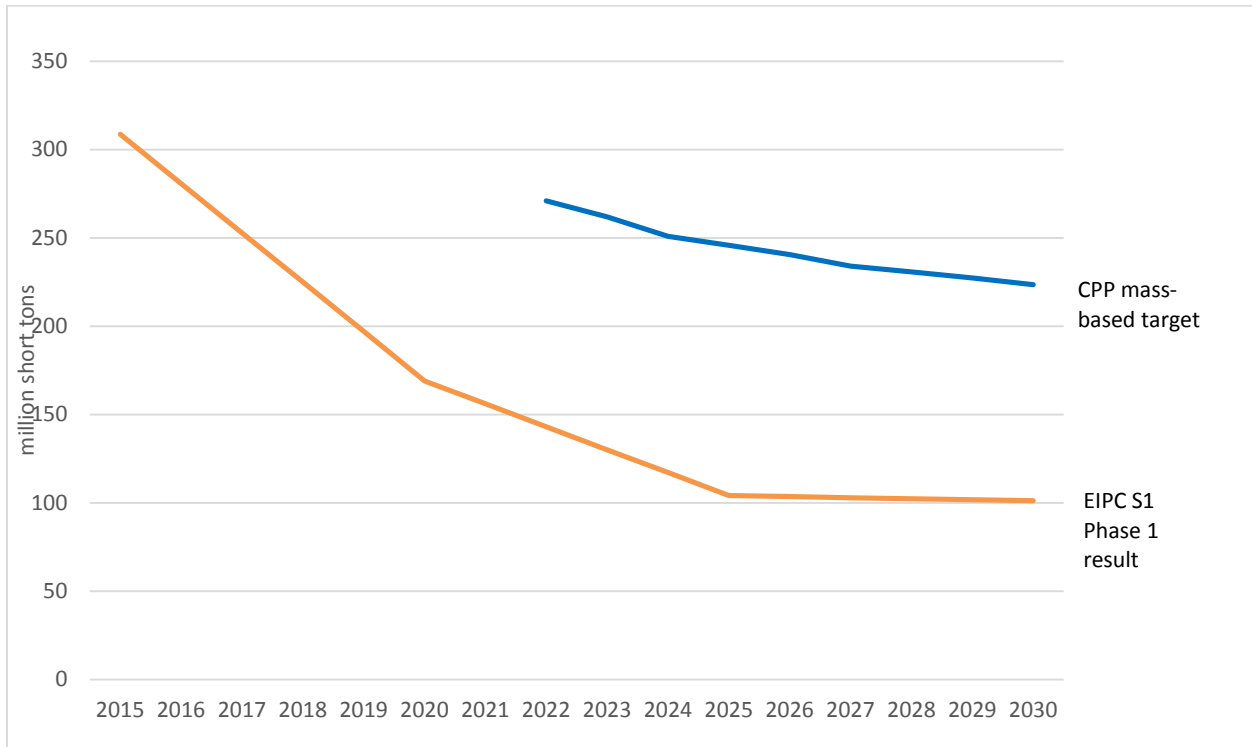
Figure 16. Coal Unit Retirements (Cumulative) in PJM in Scenarios 1 (Carbon Reduction) and 3 (Business as Usual)



Source: Synapse.

As in MISO, the significant coal unit retirements allow for steep reductions in carbon emissions. While not as deep as MISO’s cuts, PJM’s emissions drop substantially through the analysis period: to less than 100 million tons, or about one-third of 2015 emissions. Figure 17 shows that emissions reductions in the EIPC’s Carbon Reduction scenario far exceed the targets in the final Clean Power Plan for PJM states, ultimately emitting less than half of what is allowed under the CPP.

Figure 17. EIPC vs. Clean Power Plan CO₂ Emissions Targets for PJM



Source: Synapse.

Table 8. Summary of PJM Regional Results of EIPC Business-as-Usual and Carbon Reduction Scenarios

	PJM States					
	2015		2020		2030	
	<u>Business-as-Usual</u>	<u>Carbon Reduction</u>	<u>Business-as-Usual</u>	<u>Carbon Reduction</u>	<u>Business-as-Usual</u>	<u>Carbon Reduction</u>
Coal retirements cumulative (MW)	24,608	51,430	31,312	69,614	31,312	80,102
New wind capacity cumulative (MW)	9,956	9,956	9,956	10,897	16,707	14,292
Carbon dioxide emitted (million tons)	450	309	405	169	399	101
Clean Power Plan carbon dioxide allowed (million tons allowed in 2022 and 2030)			270	270	224	224

Clearly, both PJM and MISO could significantly over-comply with the Clean Power Plan by implementing something akin to the reliable, cost-effective system expansion plan developed through the EIPC process.

4. CONCLUSIONS

The EPA's final Clean Power Plan allows for, and even encourages, states to work together to maximize opportunities for cost-effective CO₂ emissions reductions from the electric power sector. The EIPC process provides an important example of how this type of coordination could not only achieve the CPP targets, but how much more aggressive emissions reductions could be achieved at little (if any) additional cost.

The EIPC was an unprecedented effort in comprehensive, large-scale coordinated electric system planning to meet specific environmental policy goals. Led by the region's experienced Planning Authorities, including the largest RTOs in the country (whose mandate is reliability), this analysis found that a scenario in which vast quantities of wind were built in the Midwest, coupled with aggressive implementation of a national RPS and energy efficiency and demand response measures, could achieve CO₂ reductions well beyond the Clean Power Plan targets while maintaining grid reliability—all for less than a 2 percent increase in cost compared with a business-as-usual approach.

The EIPC analysis did not account for the social value of CO₂ and other emissions reductions, nor for the benefit of recycling CO₂ revenues back into the electric sector. What's more, since the EIPC process was completed in 2012, the economics and technological feasibility of wind power (as well as other renewable and demand response technologies) have improved significantly, suggesting that a re-analysis of the EIPC results may even show that the Carbon Reduction scenario is now more cost-effective than the Business as Usual scenario.

As scientists reaffirm the importance of reducing heat-trapping emissions that contribute to global climate change and the federal EPA moves forward with implementing its carbon reduction mandates, energy and environmental planners need not reinvent the wheel when looking for solutions. The EIPC process provides a full-scale illustration of a CO₂ reduction scenario that exceeds the EPA targets across the Eastern Interconnect.

APPENDIX A: SYNAPSE SENSITIVITIES ON EIPC SCENARIOS

The EIPC Phase 2 report describes a series of alternative sensitivities tested in the EIPC production cost analyses (Section 6.1 of the Phase 2 report) to examine the causes of excessive wind curtailment in the Carbon Reduction (S1) scenario. The wind curtailment issue was alarming because a significant portion of the newly installed wind generation was “curtailed” (i.e., not used). The excessive wind curtailment suggested that there was a problem either with the transmission build-out developed by the planners (not enough transmission to get the wind generation to the load) or the amounts or locations of wind generation. It would be uneconomic to build as much wind generation, or select locations on the grid, if there were insufficient transmission available to make full use of it. While some marginal level of curtailment is reasonable, the levels seen in the Phase 2 report for the Carbon Reduction scenario (e.g., 40 percent of the potential produced wind energy from the modeled build-out in Nebraska, and 25 percent of the potential produced wind energy from the modeled build-out in MISO West) could be considered excessive.²¹ This does not indicate the wind build-out was not economic—indeed, the results from the EIPC process show that large amounts of wind, even when curtailed significantly, are still economic. In these circumstances, it is likely that improved forward-looking transmission modeling could find and relieve transmission constraints to allow less curtailment.

Two sensitivities were designed as variations on the Carbon Reduction (S1) scenario. They sought to examine how a realistic build-out might handle or account for significant new wind additions without curtailing or trimming a large fraction of the available wind. These two sensitivities also review how improving the costs of wind production might influence the EIPC outcomes. These two sensitivities were:

- A: Reduce wind build-out to reduce wind curtailment
- B: Improve transmission to reduce wind curtailment

By the time the EIPC report was released, the cost of utility-scale wind projects had fallen substantially, and is even lower today. To explore this dynamic, we also reviewed both of these sensitivities with new estimates for the capital cost of wind.

Sensitivity A: Reduced Wind

Rather than attempt to improve the EIPC’s transmission modeling, we explored a scenario in which we simply cut back the amount of procured wind to a level at which significant curtailment is mitigated. In other words, we sought a scenario whereby we could build less wind capacity but still obtain significant wind energy.

²¹ See Table 4-7, “Wind Curtailments by NEEM Region (TWhs)” in the EIPC Phase 1 report (p. 54).

To try and improve the wind capacity factors and reduce the wind curtailment, one of the EIPC sensitivities simply reduced the amount of wind built in specific regions. Synapse produced adjusted production costs and revised capital investment estimates in line with this sensitivity, assuming that natural gas combined-cycle (NGCC) units are on the margin when wind energy is increased (if and when increased). Thus, if more wind could reach the grid, less NGCC energy would be needed.

First, the total amount of new wind built in four regions (MISO Missouri/Illinois, MISO West, Nebraska, and Southwest Power Pool North) was reduced in the EIPC sensitivity by the amount shown in the Phase 2 report; that sensitivity scaled the new wind capacity to between 61 and 85 percent of the initially installed amounts. To accomplish this, the EIPC modeling sensitivity run assumed that in every year new wind was assumed to be built (as reported in the Phase 1 results), only a fraction of that new wind was actually procured—in other words, the reduction was scaled across all years equitably. Wind capacity factors as reported in the Phase 2 report were then adjusted by the reduced curtailment values shown in Table 6-4 of the Phase 2 report, resulting in slightly to significantly higher capacity factors. The changed capacity factors, along with the reduced wind capacity in 2030, produced 65.5 TWh less energy in 2030 than in the base version of Scenario 1. During the EIPC sensitivity run, the model filled this 65.5 TWh energy gap with natural gas, or it increased capacity factors, to make up 65.5 TWh. This type of calculation was repeated across all years.

Ultimately, this sensitivity resulted in *increased* emissions for the Carbon Reduction future (so that the emissions goals of the scenario were not fully achieved). However, it also reduced the present value revenue requirements (PVRR) of wind capital costs by \$61 billion and increased fuel costs (i.e., gas) by \$26 billion. In total, it reduced the PVRR of Carbon Reduction Scenario 1 by \$33 billion, bringing the total cost of the scenario down to \$2,391 billion from \$2,424 billion—which would make the overall costs of this sensitivity/scenario essentially the same as the Business as Usual (S3) scenario, with its PVRR of \$2,376 billion (without factoring in the extremely high value of the reduced emissions of this sensitivity compared with Scenario 3).

Sensitivity B: Improved Transmission Leads to Reduced Curtailment

An alternative sensitivity was developed by Synapse in 2013 to test the effect of reducing wind curtailment to 5 percent, which was to be accomplished by assuming that sufficient additional “economic”²² transmission would be developed that would avoid the heavy curtailment of wind in the Midwest. This transmission would consist of reinforcement of the weakest links remaining on the grid after the major generation interconnection, constraint relief, and interregional transmission path build-outs from EIPC Tasks 7 and 8 were completed. Annual wind curtailment in 2030 was set at a maximum of 5 percent (reduced from up to 40 percent in Nebraska), but no changes were made to the amount of wind capacity on the system. As a result, in 2030 wind was calculated to provide 94 TWh (or 13 percent) more energy than estimated in Phase 2 for Carbon Reduction Scenario 1. To reduce the wind

²² As compared with reliability-required transmission.

curtailment to 5 percent, this sensitivity assumes increased transmission investments of \$10 billion (real), spread over the same timeline as other transmission investments. This \$10 billion transmission investment estimate was based on improvements to underlying 345 kV and 230 kV system elements that were key “choke points” or “flow gates” on the system, as revealed in the Phase 2 production cost analyses and sensitivities.²³ We note that the overall capital investment for transmission is relatively small compared with supply-side investments for new resources and production costs over the life of the investments, and thus, even with higher levels of incremental transmission to mitigate the effect of choke points, the magnitude of the overall results would be roughly the same as is seen here.

This sensitivity reduced fuel costs by \$38 billion (PVRR), and increased total transmission costs by \$10 billion. In total, it reduced the PVRR of Carbon Reduction (S1) scenario by \$31 billion, bringing the total present value cost down to \$2,393 billion from \$2,424 billion, which would make the overall costs of this sensitivity/scenario essentially the same as the Business as Usual (S3) scenario, with its PVRR of \$2,376 billion (without factoring in the extremely high value of the related emissions of this sensitivity compared with Scenario 3).

Wind Capital Cost Adjustment

A final sensitivity was applied to both of the sensitivities discussed above: an improved learning curve for wind capital costs. Materials supplied with Phase 2 show an assumption of about 10 percent improvement in the overnight capital cost of wind from 2015 to 2025. We assumed that the unit capital cost of wind could be improved by 1 percent per year through the full analysis period, or 15.5 percent by 2025 and 30 percent by 2040.²⁴ However, since the vast majority of new wind is assumed to be brought online through 2025, the full impact of this assumption is an improvement in overnight capital costs of about 3.5 percent in 2020 and 5 percent in 2025. The real overnight cost was reduced in 2025 from \$2,216/kW to \$2,091/kW.

This assumption affects only the capital spending assumption. For the first sensitivity (reduced wind), this assumption reduces the PVRR of new-build wind capital costs by about \$19 billion, to a total of \$2,372 billion. This assumption reduces the second sensitivity by \$22 billion, for a total PVRR of \$2,371

²³ The \$10 billion estimate was derived by making an allowance for 100 reinforcement projects costing \$100 million each, to supplement the specified build-out for Scenario 1. In reality, the reinforcement projects will vary in size, with many under \$100 million and some over \$100 million. This estimate, which is based on the range of costs typically seen for upgrades of 230 kV and 345 kV circuits and transformer additions, will allow for upgrades to flow gate elements that were the cause of binding congestion in the GE MAPS production cost runs for Scenario 1.

²⁴ See, for example, Figures ES-3 in IEA Wind Task 26: The Past and Future Cost of Wind Energy, Work Package 2. Lead authors: Eric Lantz: National Renewable Energy Laboratory, Ryan Wiser: Lawrence Berkeley National Laboratory, Maureen Hand: National Renewable Energy Laboratory. Contributing authors: Athanasia Arapogianni: European Wind Energy Association, Alberto Ceña: Spanish Wind Energy Association, Emilien Simonot: Spanish Wind Energy Association, Edward James-Smith: Ea Energy Analyses. NREL Technical Report NREL/TP-6A20-53510, May 2012. Online at www.ieawind.org/index_page_postings/WP2_task26.pdf.

billion, which would make the overall costs of this sensitivity/scenario essentially the same as the Business as Usual (S3) scenario, with its PVRR of \$2,376 billion (without factoring in the extremely high value of the related emissions of this sensitivity compared with Scenario 3).

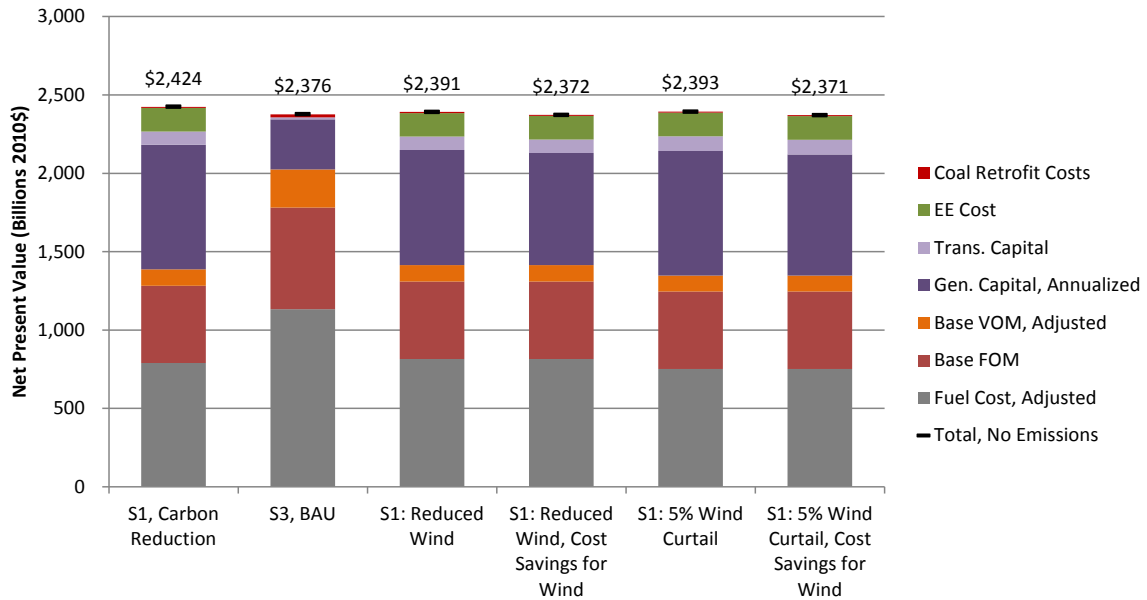
We note that current estimates of wind capital costs, such as those contained in the DOE Wind Vision study (April 2015), are even lower, further demonstrating the economic superiority of an expanded wind build-out over the Business as Usual scenario. For example, the DOE Wind Vision study estimates overnight costs of wind at approximately \$1,750/kW in 2014—or more than 25 percent lower than the EIPC’s assumption.²⁵ Following the Wind Vision assumptions through 2040 (from 2015), the overall cost of the reduced wind sensitivity falls by \$100 billion to \$2,291 billion, or effectively the same cost as the Business as Usual (S3) scenario.

Present Value of Revenue Requirements for Scenarios 1 and 3 and Sensitivities

Overall, the PVRR of the scenarios and additional sensitivities shows that—without factoring in the costs of emissions— Carbon Reduction (S1) scenario can be achieved at approximately the same cost as Business as Usual (S3) scenario, provided that a CO₂ cap is used instead of a CO₂ price, or costs incurred for CO₂ emissions are recycled back as clean energy investments or returned to customers (Figure). Options to reduce wind curtailment provide value and reduce costs. Ultimately, if the cost of wind turbines drops in accordance with the assumptions in our sensitivities here (1 percent per year), a scenario with reduced wind or a scenario with improved transmission and reduced curtailment would provide cost savings relative to a business-as-usual trajectory.

²⁵ See DOE Wind Vision Report, Appendix H, Section H.1.3: Future Wind Plant Cost and Performance Assumptions. The Mid Cost scenario assumes 2030 overnight costs of \$1,518/kW to \$1,724/kW.

Figure 18. Net Present Value of Revenue Requirements of Scenarios 1 and 3 and Sensitivities, Excluding Emissions Costs



Source: Synapse, *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process: Preliminary Results.*

APPENDIX B: TABLES

Table 9. Eastern Interconnection Cumulative New Builds Summary

	Scenario 1—Carbon Reduction			Scenario 3—Business as Usual		
	2015	2020	2030	2015	2020	2030
Eastern Interconnection Cumulative New Builds (MW)						
PJM	41,061	44,717	50,672	22,260	24,224	38,907
MISO	20,551	35,362	133,741	9,422	18,562	28,940
Eastern Interconnection Cumulative New Natural Gas Combined Cycle (MW)						
PJM	28,191	28,191	28,191	9,390	9,510	14,700
MISO	11,129	25,160	25,160	0	4,663	7,040
Eastern Interconnection Cumulative New Onshore Wind (MW)						
PJM	9,956	10,897	14,292	9,956	9,956	16,707
MISO	6,069	6,631	103,853	6,069	8,060	12,639
Eastern Interconnection Coal Retirements (MW)						
PJM	51,430	69,614	80,102	24,608	31,312	31,312
MISO	25,274	46,404	60,182	9,049	12,522	12,522

Table 10. PJM and MISO CO₂ Emissions (million short tons), 2015–2021

	2015	2016	2017	2018	2019	2020	2021
EIPC Scenario 1 Phase 1 Results (Synapse Adjusted)							
PJM	308.6	280.7	252.8	224.9	197.0	169.1	156.1
MISO	304.0	295.5	287.1	278.6	270.1	261.7	221.8

Table 11. PJM and MISO CO₂ Emissions (million short tons), 2022–2030

	2022	2023	2024	2025	2026	2027	2028	2029	2030
EIPC Scenario 1 Phase 1 Results (Synapse Adjusted)									
PJM	143.1	130.1	117.1	104.1	103.5	102.9	102.3	101.8	101.2
MISO	181.9	142.1	102.2	62.3	61.1	59.9	58.7	57.5	56.2
Clean Power Plan Mass-based Targets									
PJM	270.9	261.9	250.8	245.9	240.5	234.0	230.8	227.4	223.5
MISO	486.4	468.7	446.0	436.5	426.3	413.9	406.1	397.7	388.4