EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Data Mining White Paper

December 2014

Navigant Consulting, Inc.
For EISPC and NARUC

Funded by the U.S. Department of Energy

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This material is based upon work supported by the U.S. Department of Energy, under Award Number DE-OE0000316.

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The material in this white paper is included as Topic 14 in the "Additional EIPC Study Analysis: Final Report" issued in December 2014 by Oak Ridge National Laboratory for the U.S. Department of Energy, prepared by Stanton W. Hadley of Oak Ridge National Laboratory, Douglas J. Gotham of Purdue University and Ralph Luciani of Navigant Consulting, Inc.. Stanton Hadley and Douglas Gotham also co-authored the Topic 14 material reproduced herein.

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December 2014

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1 Introduction

Between 2010 and 2012 the Eastern Interconnection Planning Collaborative (EIPC) conducted a major long-term resource and transmission study of the Eastern Interconnection (EI). With guidance from a stakeholder steering committee (SSC) that included representatives from the Eastern Interconnection States' Planning Council (EISPC) among others, the project was conducted in two phases. The first was a 2015–2040 analysis that looked at a broad array of possible future scenarios, while the second focused on a more detailed examination of the grid in 2030. The studies provided a wealth of information on possible future generation, demand, and transmission alternatives.

However, at the conclusion there were still unresolved questions and issues, many of which were examined in the "Additional EIPC Study Analysis: Final Report" issued in December 2014 by Oak Ridge National Laboratory for the U.S. Department of Energy, prepared by Stanton W. Hadley of Oak Ridge National Laboratory, Douglas J. Gotham of Purdue University and Ralph Luciani of Navigant Consulting, Inc. The material in this white paper appears as Topic 14 in that report.

In Phase 1 of the EIPC study, the term "futures" was used to define a consistent set of input assumptions on technologies, policies, and costs. Eight futures were defined by the SSC in an attempt to cover a wide range of possible policies. The eight are listed in Table 1, along with a description and the short label used for each in this report.

Table 1. List of Futures Studied in Phase 1

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

This white paper specifically examines the input assumptions used in the EIPC study formulated by stakeholders largely in the late 2010 to early 2011 time frame. These inputs included such key assumptions as projected gas prices, electricity demand, capital costs for new generation resources, and DG installations. There were multiple sensitivities conducted in the EIPC study to help capture the impact of uncertainty around these key assumptions.

These input assumptions are now roughly 4 years old and updated estimates are available. This whitepaper examines the sensitivity of the results to the assumptions whose estimates have changed substantially since the EIPC study. Four key assumptions were identified for examination: (1) capital costs for new generation resources, (2) distributed solar projections, (3) electricity demand, and (4) environmental policies. Each key assumption is examined in turn below.

2 Capital Costs

The capital costs of new generation resources such as combustion turbines (CTs), combined-cycle (CC) facilities, and wind power facilities are a key determinant in the type of new generation that will be constructed. Using the same methods and sources applied by EIPC study stakeholders in 2010–2011, we updated the costs of these resources to 2014. For capital cost assumptions, the main source used in the EIPC study was the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2011 (EIA 2011). Updated EIA capital costs were obtained from AEO 2014 (EIA 2014), and the comparison to the EIPC study assumptions is provided in Table 2. Also shown are the cumulative additions by 2030 for each capacity type in each of the three EIPC Phase 2 futures.

Table 2. Capital Costs for New Generation Resources by In-Service Year [$/kW (2012$)]

	EIPC Study		2014 Update		Increase		EIPC 2030 Additions (GW)		
Technology	2015	2030	2015	2030	2015	2030	BAU	RPS/R	CO_2+
Nuclear	5,679	5,282	5,762	5,369	1%	2%	7	7	36
Advanced Coal	2,957	2,851	2,961	2,856	0%	0%	8	8	8
CC, H-Frame	1,061	1,024	1,052	1,015	−1%	−1%	75	30	108
CT	730	705	720	696	−1%	−1%	14	21	5
IGCC	3,343	3,224	3,805	3,670	14%	14%	1	1	1
IGCC (w/sequestration)	5,428	4,993	6,575	6,061	21%	21%	0	0	0
Wind	2,485	2,304	2,223	2,144	−11%	−7%	49	141	243
Wind Offshore	5,880	4,992	6,185	5,743	5%	15%	2	38	2
Photovoltaic	4,684	3,978	3,570	3,315	−24%	−17%	5	5	4
Solar Thermal	4,622	3,925	5,044	4,683	9%	19%	0	0	0
Biomass	3,826	3,253	3,943	3,663	3%	13%	2	26	2
Geothermal	4,205	3,897	4,364	4,052	4%	4%	0	0	0

As shown, the updated capital costs for nuclear, advanced coal, CCs and CTs are largely unchanged from those used in the EIPC study. While the cost of integrated gasification, combined cycle (IGCC), with or without sequestration, is projected to be more expensive today, little or no new IGCC was constructed in the EIPC study.

The projected capital cost of onshore wind turbines is 7% to 11% lower today than in the EIPC study. If everything else were equal, this would result in the construction of more wind power facilities than projected in the EIPC study. Any increase would be tempered by other EIPC study input assumptions limiting the penetration of intermittent resources and the extent to which in a given future wind facilities were constructed primarily to meet RPS requirements.

The projected cost of offshore wind facilities is roughly 15% higher today than projected in the EIPC study. In most EIPC study scenarios, few or no offshore wind facilities were constructed. However, in the RPS/R future, this increase in the cost of offshore wind facilities would have acted to decrease the number constructed (38 GW through 2030), all else equal.

Little or no solar thermal or geothermal capacity was constructed in the EI through 2030 in the EIPC study, thus the increase in projected capital costs shown in Table 2 would not have had much impact.

One key change is in the projected capital cost of photovoltaic (PV) solar capacity, which has declined by 15% to 25% today from the time of the EIPC study. PV solar capacity was constructed in the EIPC Phase 2 futures, largely to meet solar RPS requirements. Given the corresponding increase in the capital cost of biomass capacity, it is plausible that PV solar would substitute to a certain extent for biomass in the RPS/R scenario and possibly, depending on location, for onshore wind in all three scenarios.

3 Distributed Solar

3.1 Distributed Solar Modeling

Generator modeling in the EIPC study model focused on central station facilities rather than end-user-owned distributed generation (DG). To model the accelerated acceptance of DG for the EE/DR/DG and CO_2+ futures, the Stakeholder Steering Committee (SSC) Modeling Working Group (MWG) had to decide (1) how much to accelerate the growth, (2) what technology to model, and (3) how to incorporate it into the model.

Many of the inputs used in the analysis were based on the EIA 2011 early reference case. Included in its output are DG estimates. Customer demands for the EIPC study were based on utility demands that already had the DG production demands removed. If further DG is built, then demands must be further reduced to reflect the additional generation. The MWG decided that a plausible acceleration of DG would be to have a doubling of DG over the coming years. By 2030, DG reduces demand across the EI by 4% (24 GW). Figure 1 shows the amount of DG capacity for the EI in comparison to the demands in the BAU and EE/DR/DG futures (that also include a flattening due to EE). The CO_2+ future had the same demands as the EE/DR/DG future.

The additional DG next had to be allocated to the different North American Electricity and Environment Model (NEEM) regions. The AEO 2011 reports the amounts for each of the 22 regions used in its model. These amounts had to be converted to the 32 NEEM regions used in the EIPC study. Most regions have similar borders but the NEEM regions included some further disaggregation and Canadian provinces. A matrix was created to weight the amounts based on total electricity sales. Once determined, the additional capacity growth was allocated to each region for each year of the study.

The MWG recommended that this new DG be modeled as solar capacity. Because solar is generated intermittently, this required knowledge of the hourly patterns. Researchers at National Renewable Energy Laboratory (NREL) selected key cities near the center of each NEEM region and calculated the hourly generation from a 1 kW, fixed tilt panel for each hour of 2006 using their System Advisor Model. The average value represents the capacity factor for each region, which ranged from 16.5% in SPP S to 11.3% in NYISO. The year 2006 was selected because it matches the demand and wind profiles that were used elsewhere in the study.

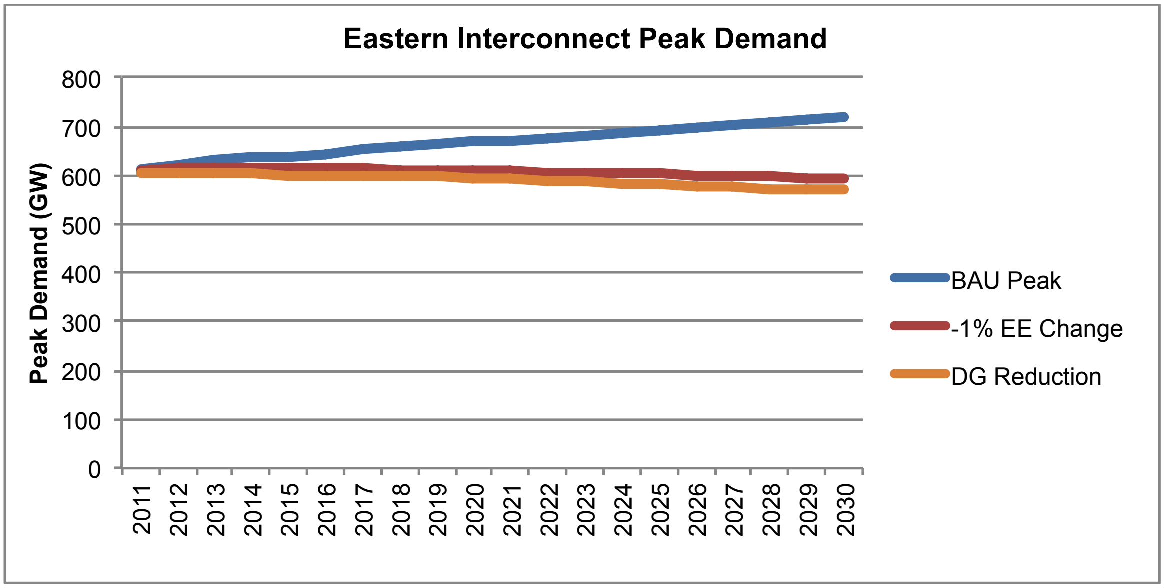


Figure 1. Eastern Interconnection peak demand in the BAU and EE/DR/DG (and CO_2+) futures before and after DG reductions.

Charles River Associates (CRA) provided a schedule of the demands by hour for the EI. The NEEM model uses 20 blocks of varying size to represent the 8,760 hours of the year. The DG production for each region in each hour was calculated by multiplying the DG capacity with the NREL irradiance data. These were aggregated into the 20 blocks to determine the energy production and consequent demand reduction for each block over the study period. The new demand and peak demand amounts were then supplied to CRA for calculations in NEEM.

3.2 Distributed Solar EIPC Study Inputs

A comparison was made to current (EIA 2014) projections of PV solar capacity in 2030 with those projected in the EIPC study, considering both utility and distributed solar. Certain simplifying assumptions were used to derive the results for the US portion of the EI from the total EIA 2014 PV results.

Total PV solar, both in service in the electric power sector (i.e., central stations) and in service in the end-use sector (distributed solar), is shown in Table 3. The EIA 2014 reference case has 12 GW of total PV solar in service in 2030, of which 10 GW was distributed solar. In comparison, the BAU future in the EIPC study had 9 GW of total PV solar in service in 2030, of which 6 GW was distributed solar. In the EIA 2014 sensitivity cases, the total PV solar capacity in the US EI reached as high as 25 to 30 GW by 2030, with the share of distributed solar ranging from 50% to 90%. In comparison, the CO_2+ case in the EIPC study had total PV solar capacity of 33 GW in the US EI in 2030, of which about 90% was distributed solar.

Table 3. Total Installed Photovoltaic Solar Capacity in the US EI Regions in 2030 (GW)

	EIA 2014 Cases							EIPC Study Futures		
Sector	Reference	No Sunset	Low Cost Renewable	GHG 25	High Growth	Low Growth	High Price	BAU	RPS/R	CO_2+
Electric Power	2	4	5	12	3	2	2	4	4	3
End-Use	10	26	13	13	11	9	10	6	6	30
Total	12	30	18	25	14	11	12	9	9	33

While the total amount of solar capacity in service in the EIPC study in 2030 was somewhat lower than today's EIA 2014 projections in the BAU and RPS/R scenarios, the CO_2+ scenario did capture the high range of solar capacity projected by EIA today.

4 Demand Projections

The projected energy demand in the EIPC study was largely taken from the AEO 2011 assumptions. However, planning authorities provided alternative estimates of growth through 2020 to reflect the estimates they provided to NERC for its long-term reliability assessment. Additionally, some regional groups on the SSC (e.g., the New England States Committee on Electricity) gave alternative growth amounts to reflect additional savings from established EE plans. Figure 2 and Table 4 show the projected energy demand for the US portion of the EI for the BAU scenario, as projected in the 2011 AEO, and as currently projected by EIA in the 2014 AEO (EIA 2014).

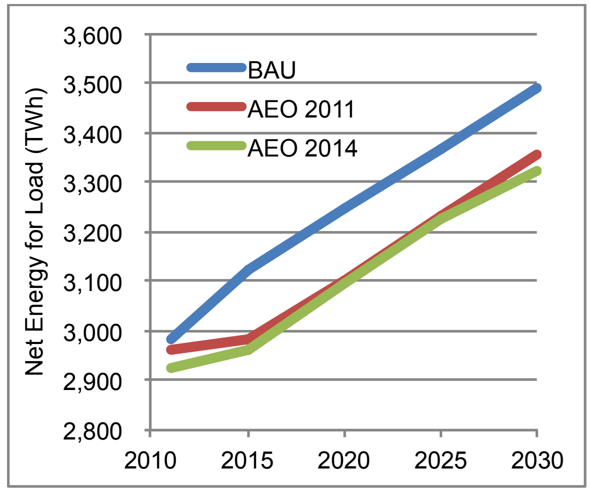


Figure 2. Energy demand in the US EI region

Projected energy demands for 2011 were relatively the same in the BAU and AEO 2011, differing just 0.7%. But the utility estimates for growth between 2011 and 2015 were an annualized 1.2% growth rate while the AEO 2011 grew at only a 0.2% rate. From 2015 on, the growth rates were similar in both projections, around 0.8% per year. This led to differences in the amounts of around 4% for the study period (Table 4.) The projected demands from the AEO 2014 are even slightly lower than the AEO 2011 so that the BAU was 4% to 5% higher than the current projection from EIA. Lowering demands by 5% could have a major impact on results.

Table 4. Energy Demand in the US Eastern Interconnection Regions

	2011	2015	2020	2025	2030
BAU					
Net Energy for Load (Twh)	2,983	3,123	3,250	3,369	3,492
Annual Growth Rate		1.2%	0.8%	0.7%	0.7%
AEO 2011					
Net Energy for Load (Twh)	2,962	2,984	3,103	3,230	3,357
Annual Growth Rate		0.2%	0.8%	0.8%	0.8%
% Reduction from BAU	−0.7%	−4.4%	−4.5%	−4.1%	−3.9%
AEO 2014					
Net Energy for Load (Twh)	2,925	2,964	3,099	3,228	3,325
Annual Growth Rate		0.3%	0.9%	0.8%	0.6%
% Reduction from BAU	−1.9%	−5.1%	−4.7%	−4.2%	−4.8%

5 Environmental Policies

5.1 Environmental Rules

With the exception of the EPA proposed Clean Power Plan, the changes to proposed/finalized environmental regulations that have occurred after the Phase 1 modeling would be unlikely to have a significant impact on the modeling results. Table 5 lists the EPA rules that were included in the EIPC analysis and summarizes their current status.

Table 5. EPA Rules Modeled in Phase 1 and Their Current Status

Phase 1	Now	Result
Transport Rule	The Cross-State Air Pollution Rule was reinstated by the Supreme Court, replacing the Transport Rule	While this may have some impact in the short term, long-term effects should be minor
Mercury and Air Toxics Standard	Finalized with minor changes	The changes should have little effect
New Source Performance Standard for CO_2	Finalized with minor changes	The options for new sources modeled in Phase 1 meet the final rule, so there would be no effect
Coal Combustion Residuals	Has not been finalized	Any change would be speculation prior to finalization
Cooling Water Intake Structures [316(b)]	Finalized with significant flexibility in terms of compliance options	It would be difficult to model the potential for each site to use various options. The flexibility in the final rule may result in lower compliance costs, but there would likely be little effect on retirement decisions.

The retrofit costs for SO_2, NO_x, and mercury were based on information dated from 2006 to 2010. While updated costs would likely differ, there have not been any recent developments that would result in significant changes.

Phase 1 included a number of forced retrofits. It is not known which of those retrofits actually occurred or are under way. If some units have not been retrofit, they may be candidates for retirement rather than retrofit.

5.2 Renewable Portfolio Standards

While no state has either added or removed an RPS since the EIPC Phase 1 modeling was completed, a number of them have made modifications to existing standards. Most of the modifications either redefined which resources qualified for the RPS or created or modified a carve-out for a specific technology within the RPS. In 2014, Ohio established a 2-year hiatus for its RPS, which pushes back the subsequent targets by 2 years. Table 6 lists the RPS modifications that have occurred since the EIPC analysis.

These modifications would likely have a small impact on the Phase 1 modeling results. The carve-outs would increase the amount of solar and offshore wind in the affected regions, but the levels of the carve-outs are small (a few percent) and only affect a few states.

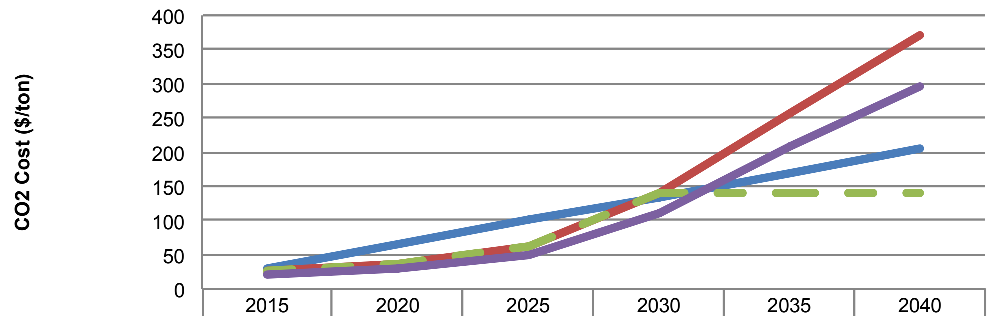
Table 6. Modifications to State Renewable Portfolio Standards

State/District	Year	Modification
CT	2013	Redefined qualifying resources
DC	2011	Increased solar carve-out from 0.4% to 2.5% by 2023
DE	2011	Redefined qualifying resources
MD	2011, 2012	Redefined qualifying resources
	2012	Accelerated solar carve-out compliance requirements
	2013	Created offshore wind carve-out for 2017 and beyond (level to be determined by the Public Service Commission at a maximum of 2.5%)
MN	2013	Created solar carve-out of 1.5% by end of 2020
MT	2013	Redefined qualifying resources
NC	2011	Allowed electricity demand reduction to count toward the standard
NH	2012	Redefined qualifying resources
NJ	2012	Increased the solar carve-out to require 4.1% by 2028
OH	2012	Redefined qualifying resources
	2014	Established a 2-year hiatus

5.3 *EPA Carbon Rules*

EPA's release of its proposed CO_2 rule for existing power plants under Section 111(d) of the Clean Air Act brings up the question of how the various Phase 1 futures and sensitivities compare to the proposed rule. Under the EPA proposed rule, CO_2 emissions in the United States are targeted to decrease by 30%. A number of Phase 1 sensitivities similarly result in significant CO_2 emissions reductions, either through the implementation of a direct carbon cost or by establishing requirements for zero or low carbon generation sources.

Futures 2 and 3 were specifically designed to achieve CO_2 emissions reductions using a cost adder associated with each ton released. These futures were designed to achieve economy-wide reductions of 42% in 2030 and 80% in 2050. To obtain these reductions in the models, a CO_2 price trajectory was first determined by solving the MRN model iteratively. An initial price estimate was implemented, the model was run, and the price was adjusted to increase or decrease emissions as appropriate. This process was repeated until the desired reductions were achieved. Figure 3 shows the initial price estimate, the final price (Base) and two different trajectories used in sensitivities. The prices labeled "Flat>2030" are identical to the Base price until 2030 and are held constant afterwards. The prices labeled "20% Lower" are 20% below the Base price for all years.



	2015	2020	2025	2030	2035	2040
Initial	30	65	100	135	170	205
Base	27	38	62	140	259	369
Flat >2030	27	38	62	140	140	140
20% Lower	21	30	50	112	207	296

Figure 3. Carbon dioxide price curves used in the EIPC study.

Because the MRN model indicated that CO_2 emission reductions in the electricity sector were more cost-effective to achieve than in other sectors of the economy, the resultant electricity sector reductions were significantly higher than the economy-wide targets of 42% in 2030 and 80% in 2050. Thus, the various Phase 1 sensitivities that incorporate CO_2 prices result in much higher levels of electricity sector emission reductions than the EPA target of 30%. The electricity sector emission reductions in 2030 under the Base price were 83% under a national implementation (F2S11) and 78% under a regional implementation (F3S12). The lower CO_2 price resulted in reductions that were 5% lower under both implementations (F2S9 and F3S8).

In contrast to the CO_2 emission reductions explicitly targeted in Futures 2 and 3, Futures 5 and 6 included a national RPS requiring that 30% of electricity generation come from renewable sources by 2030. While these futures achieve levels of CO_2 emission reduction similar to those proposed by EPA (29% in F5S10 and F6S10), they do not differentiate between higher and lower emission nonrenewable sources. Furthermore, the Phase 2 analysis resulted in significant wind curtailments when modeling the regional approach contained in the RPS/R scenario (F6S10). Thus the emission reductions indicated in Phase 1 did not all materialize in the more detailed analysis in Phase 2.

Futures 5 and 6 each contained a sensitivity that modeled a national CES. These sensitivities required that 70% of electricity generation come from clean sources, defined as renewables, gas-fired CC units, and nuclear, by 2030. These sensitivities resulted in CO_2 emissions reductions that exceeded the EPA target for 2030, 52% under national implementation (F5S5) and 54% under regional implementation (F6S4). The reductions were 27% and 23% respectively in 2020, much closer to the EPA target. The NUC future included a CES sensitivity (F7S3) that resulted in a 72% reduction in 2030.

Future 8 modeled a combination of federal policies. The combination of an RPS, charges for CO_2 emissions, and aggressive EE/DR/DG (F8S7) resulted in the greatest levels of emissions reductions at 85% in 2030. Figure 4 shows the CO_2 emissions reductions at the EI level for the BAU and various sensitivities that produce significant CO_2 emissions reductions.

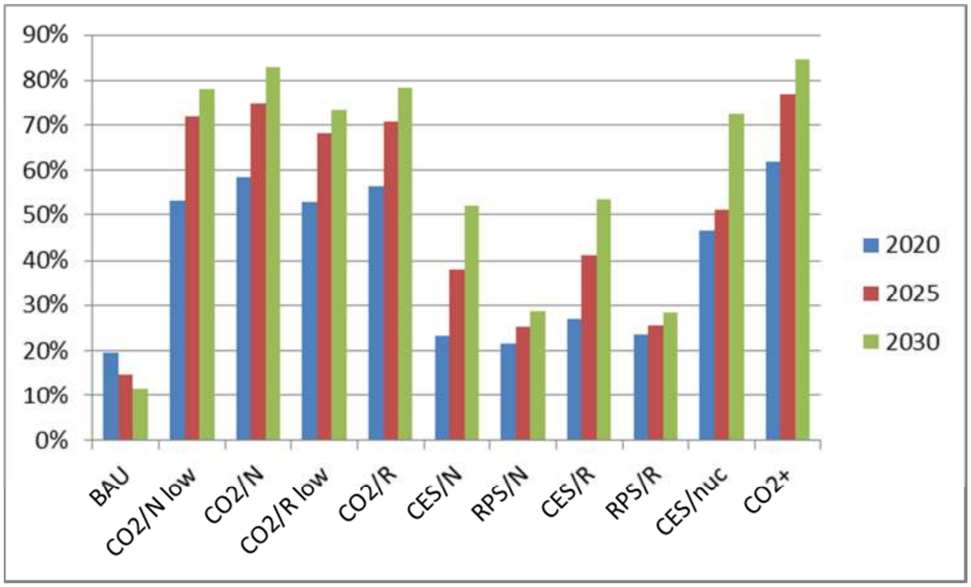


Figure 4. Carbon dioxide emissions reductions relative to 2005 levels for the BAU scenario and various sensitivities.

5.3.1 Generation Mix Impacts in Selected CO_2 Reduction Sensitivities

Because the target of the proposed EPA rule is to achieve a 30% reduction in CO_2 emissions, those sensitivities that achieve similar levels of reductions in a particular year are of interest for further analysis. These include both RPS sensitivities in 2030 (29% reduction) and the Future 5 CES/N (27%) and Future 6 CES/R (23%) sensitivities in 2020. The 2020 CO_2/N and CO_2/R low sensitivities are also included as they have the lowest CO_2 reductions of the cases that specifically target CO_2 emissions (53%).

The federal and regional implementations of the RPS in Futures 5 and 6 achieved the CO_2 reductions that most closely approximated the target of the proposed EPA rule, with both reducing emissions by 29% in 2030. As Figure 5 illustrates for the EI, the RPS sensitivities increase the amount of wind and other renewables relative to the BAU, while natural gas and coal generation are reduced. It is important to note that the Futures 5 and 6 RPS sensitivities treat natural gas and coal equally as nonrenewable sources, even though they have different levels of carbon emissions. This causes natural gas generation to drop more than it likely would if the goal were to reduce emissions rather than increase renewables.

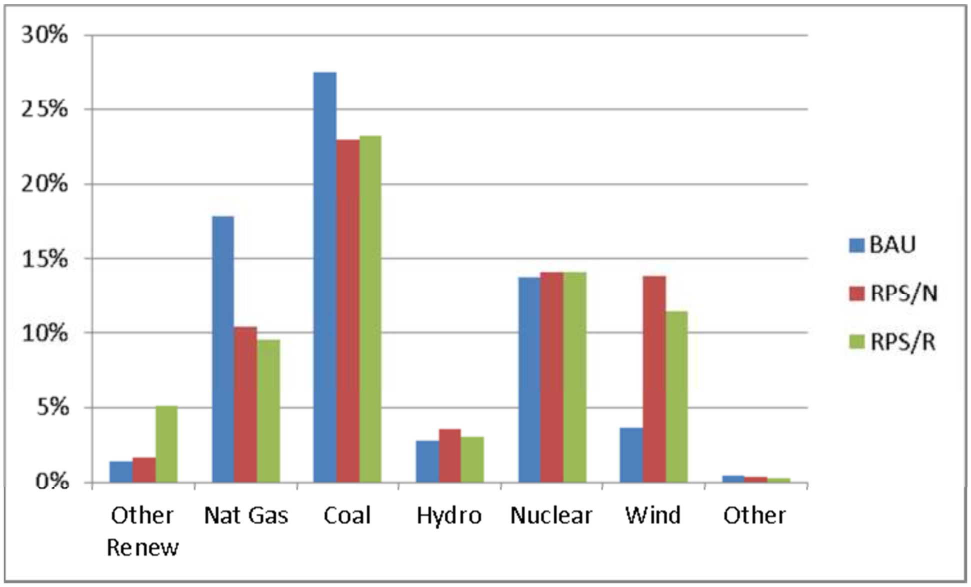


Figure 5. Eastern Interconnection electricity generation sources under the BAU and RPS sensitivities in 2030.

The Futures 5 and 6 CES sensitivities achieved 27% and 23% CO_2 emissions reductions under the regional and national approaches, respectively, in 2020. As can be seen in Figure 6, these sensitivities resulted in increased natural gas use and less coal.

The Futures 2 and 3 low CO_2 price sensitivities still produced significantly more CO_2 emissions reductions by 2020 than the EPA target. As early as 2020, both the national and regional implementations achieved a 53% reduction. While these reductions exceed the EPA target, they have the lowest levels of reductions in any of the sensitivities that are specifically designed to reduce carbon emissions. They do provide some indication of the generation mix impact that would be incurred, even though the magnitude is too large. Figure 7 shows the generation mix for the EI in 2020 for the low CO_2 price sensitivities. Natural gas and wind increase relative to the BAU, while coal decreases. The gain in share by other technologies such as nuclear and hydro comes from a decrease in demand due to higher prices rather than from an increase in generation from those sources. It should be noted that natural gas use begins to decline in later years as CO_2 prices increase.

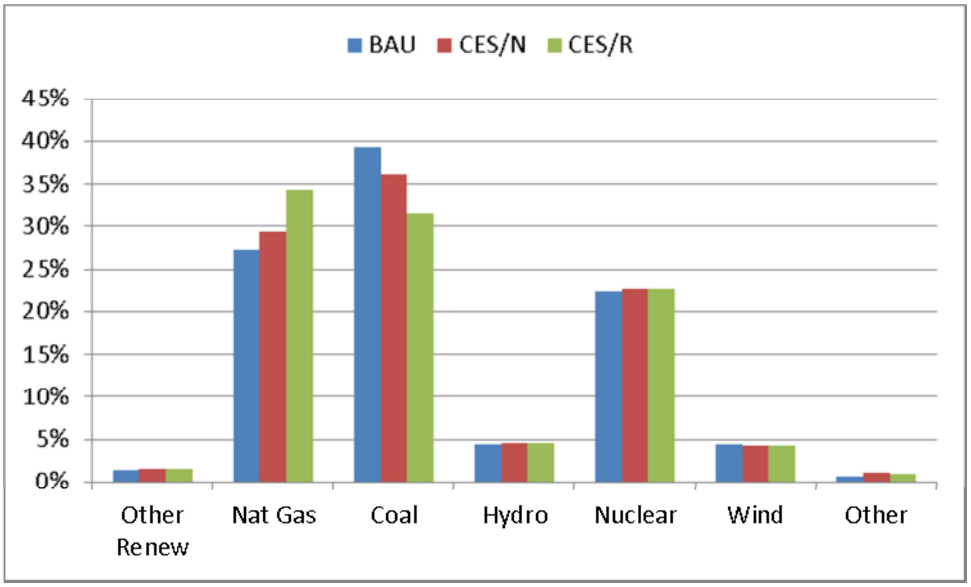


Figure 6. Eastern Interconnection electricity generation sources under the BAU and CES sensitivities in 2020.

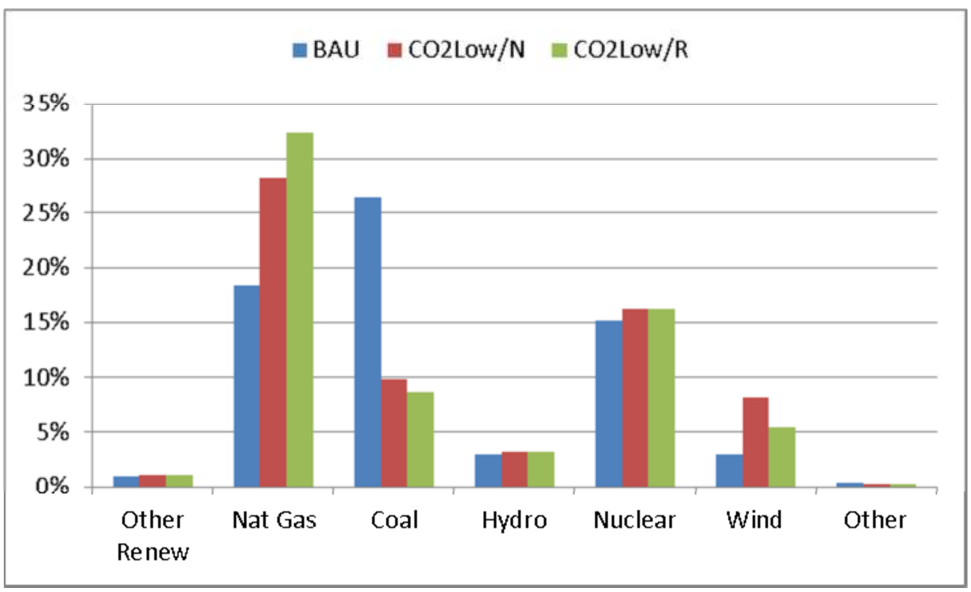


Figure 7. Eastern Interconnection electricity generation sources under the BAU and CO_2 low sensitivities in 2020.

The Future 3 and Future 5 regional implementations generally result in more natural gas and less wind than the Future 2 and Future 4 national implementations. The implementation strategy can also have a significant effect on CO_2 reductions by NEEM region. Figure 8, Figure 9, and Figure 10 show the ratio of CO_2 emissions levels in 2030 to the 2005 amounts for the two implementation strategies by NEEM region.

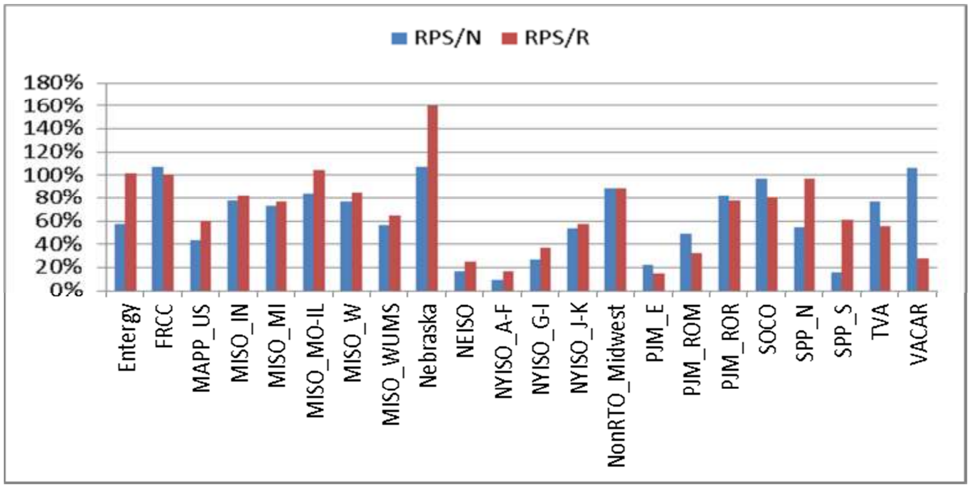


Figure 8. 2030 CO_2 emissions levels relative to 2005 by NEEM region under RPS.

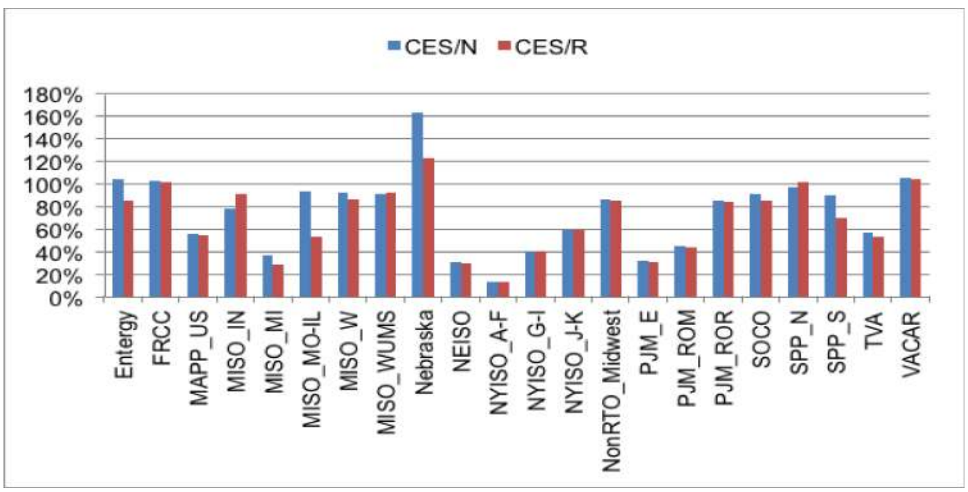


Figure 9. 2020 CO_2 emissions levels relative to 2005 by NEEM region under CES.

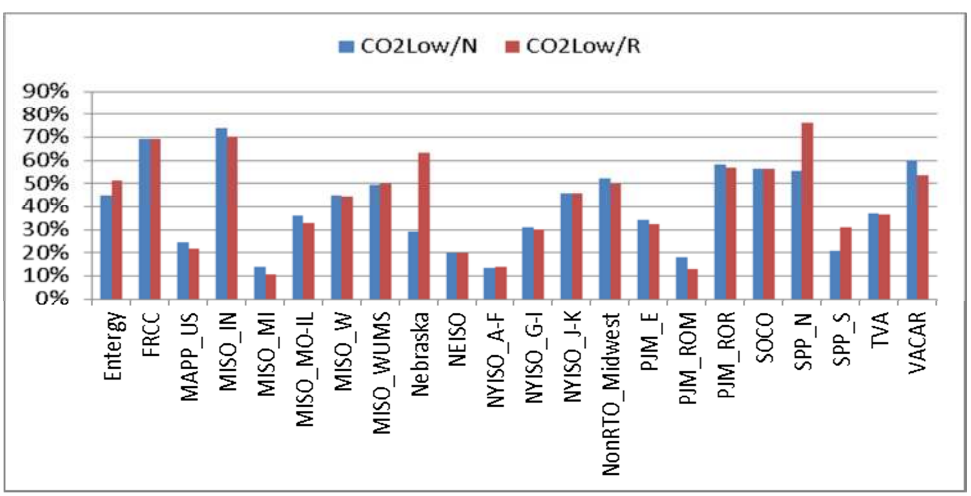


Figure 10. 2020 CO_2 emissions levels relative to 2005 by NEEM region under low CO_2 prices.

As shown, for any particular region the CO_2 emission reductions may increase or decrease under a regional or national implementation approach. This would be expected because, for example, the locations of the best national sources for reducing CO_2 or meeting RPS requirements may not be able to be fully incorporated in a regional approach. Thus, for example, the CO_2 emission levels in wind-rich regions will tend to increase under a regional implementation approach. This impact is not evident in the CES cases, where natural gas was grouped with wind as a clean energy source, mitigating the value of importing wind power in the national cases in favor of nearby natural gas.

6 Conclusions

The input assumptions used in the EIPC study were formulated by stakeholders largely in the late 2010 to early 2011 time frame. Because these input assumptions are now roughly 4 years old, this topic examined changes to four key input assumptions since the time of the EIPC study: (1) capital costs for new generation resources, (2) distributed solar projections, (3) electricity demand, and (4) environmental policies.

Capital Costs for New Generation Resources: Based on updated EIA sources similar to those used in the EIPC study, the projected capital costs of most fossil-fired resources are largely unchanged since the time of the EIPC study. The projected capital cost of onshore wind turbines is 7% to 11% lower today than in the EIPC study. All else being equal, this would result in the construction of more wind power facilities than projected in the EIPC study. Any increase would be tempered by other EIPC study input assumptions such as RPS requirements and penetration limits on intermittent resources. The projected capital cost of PV solar capacity has declined by 15% to 25% today from the time of the EIPC study. PV solar capacity was constructed in the three EIPC Phase 2 scenarios largely to meet solar RPS requirements. With these reduced capital costs, it is plausible that PV solar would substitute to a certain extent for biomass in the RPS/R scenario and possibly, depending on location, for onshore wind in all three Phase 2 scenarios.

Distributed Solar Projections: A comparison was made of current (EIA 2014) projections of PV solar capacity with those projected in the EIPC study for 2030, considering both utility and distributed solar installations. The EIA 2014 reference case has 12 GW of total PV solar in service in 2030, of which 10 GW is distributed solar. In comparison, the BAU future in the EIPC study had 9 GW of total PV solar in service in 2030, of which about 6 GW was distributed solar. In the EIA 2014 sensitivity cases, the total PV solar capacity in the US EI reached as high as 25 to 30 GW by 2030, with the share of distributed solar ranging from 50% to 90%. In comparison, the CO_2+ scenario in the EIPC study had total PV solar capacity of 33 GW in the US EI in 2030, of which about 90% was distributed solar. Overall then, while the total amount of solar capacity in service in the BAU scenario of the EIPC study in 2030 was somewhat lower than today's EIA 2014 projections, other EIPC study futures did capture the high range of solar capacity projected by EIA in some of its sensitivities.

Electricity Demand: The projected energy demand used in the EIPC study for the first 10 years was largely from the individual planning authorities for their regions, while later years used the growth rates from the 2011 AEO. Projected energy demands for 2011 were relatively the same in the BAU and 2011 AEO, differing just 0.7%. But the utility estimates for growth between 2011 and 2015 were an annualized 1.2% growth rate while those in the 2011 AEO grew at only a 0.2% rate. From 2015 on, the growth rates were similar in both projections, around 0.8% per year. This led to differences in the amounts of around 4% for the study period. The projected demands from the 2014 AEO are even slightly lower than the 2011 AEO, so that the BAU was 4% to 5% higher than the current projection from EIA. Lowering demands by 5% could have a major impact on results.

Environmental Policies: With the exception of EPA's proposed Clean Power Plan, the changes to proposed/finalized environmental regulations that have occurred after the Phase 1 modeling would be unlikely to have a significant impact on the modeling results. These changes include the reinstatement of the Cross-State Air Pollution Rule and the finalization of the Mercury and Air Toxics Standard, the New Source Performance Standard for CO_2, and the Cooling Water Intake Structures rule. Similarly, changes in state RPS requirements would not have a major impact. No new state RPS has been added, and the modifications to existing ones have primarily been a redefinition of the resources that qualify or the creation of a carve-out for a specific technology. The most significant modification is in Ohio, which has established a 2-year hiatus for its RPS. The restrictions on CO_2 emissions associated with the proposed Clean Power Plan would have a much greater effect. A number of Phase 1 sensitivities result in significant reductions in CO_2 emissions, but they are not close matches to the proposed rule. The CO_2 futures result in much greater reductions, while the RPS futures do not differentiate between higher and lower emission nonrenewable sources. Even though these sensitivities do not model the proposed rule specifically, they do indicate that a reduction in coal use, combined with an increase in renewables and natural gas, is a likely outcome.