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Additional EIPC Study Analysis: Final Report

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December 2014

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OAK RIDGE NATIONAL LABORATORY
MANAGED BY UT-BATTELLE FOR THE US DEPARTMENT OF ENERGY

ORNL/TM-2014/480

Electrical and Electronics Systems Research Division

ADDITIONAL EIPC STUDY ANALYSIS: FINAL REPORT

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ABBREVIATIONS AND ACRONYMS

AEO	*Annual Energy Outlook* (EIA report)
BA	balancing area
BAU	business as usual
CC	combined cycle
CES	Clean Energy Standard
CO_2/N	high CO_2 cost, implemented nationally (future)
CO_2/R	high CO_2 cost, implemented regionally (future)
CO_2+	high CO_2 cost + aggressive EE, DR, and DG + national RPS (future)
CRA	Charles River Associates
CT	combustion turbine
DG	distributed generation
DOE	US Department of Energy
DR	demand response
EE	energy efficiency
EI	Eastern Interconnection
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States' Planning Council
EPA	US Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GE MAPS	General Electric Multi-Area Production Simulation (software)
HVDC	high voltage direct current
IGCC	integrated gasification, combined cycle
LMP	locational marginal price
MRN-NEEM	Multi-Region National–North American Electricity and Environment Model
MWG	Modeling Working Group (SSC)
NADR	*National Assessment of Demand Response Potential* (FERC report and model)
NEEM	North American Electricity and Environment Model
NERC	North American Electric Reliability Corporation
NUC	nuclear resurgence (future)
O&M	operation and maintenance
ORNL	Oak Ridge National Laboratory
PEV	plug-in electric vehicle
PSS/E	Power System Simulator for Engineering (from Siemens)
PTC	production tax credit
PV	photovoltaic
RPS	renewable portfolio standard

RPS/N	RPS, implemented nationally (future)
RPS/R	RPS, implemented regionally (future)
RTO	regional transmission operator
SMR	small modular reactor
SSC	stakeholder steering committee
SSI	Stakeholder-Specified Infrastructure
TWh	terawatt-hour = 1,000 gigawatt-hours = 10^6 megawatt-hours = 10^9 kilowatt-hours

EASTERN INTERCONNECTION MEMBERS/REGIONS
(also referred to as NEEM regions in this report)

ENT	Entergy Corp. plus other utilities in central Missouri, Arkansas, Louisiana, Mississippi, east Texas
FRCC	Florida Reliability Coordinating Council—Florida minus the panhandle
IESO	Independent Electricity System Operator, Ontario Canada
MAPP CA	Mid-Continent Area Power Pool—Canada (Manitoba-Saskatchewan)
MAPP US	Mid-Continent Area Power Pool—US (non-MISO regions in Montana, North Dakota, South Dakota, Minnesota, Iowa)
MISO IN	Midcontinent Independent System Operator—Indiana
MISO MI	Midcontinent Independent System Operator—Michigan
MISO MO-IL	Midcontinent Independent System Operator—Missouri-Illinois (eastern Missouri, much of Illinois)
MISO W	Midcontinent Independent System Operator—West (parts of Montana, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin)
MISO WUMS	Mid-continent Independent System Operator—Wisconsin-Upper Michigan
NE	Nebraska
NEISO	New England Independent System Operator
Non-RTO Midwest	Non-Regional Transmission Operator Midwest (most Kentucky, some Ohio public utilities)
NYISO A-F	New York Independent System Operator—Upstate
NYISO G-I	New York Independent System Operator—lower Hudson Valley
NYISO J-K	New York Independent System Operator—New York City-Long Island
PJM	Independent System Operator for territory from Chicago to Virginia (formerly the Pennsylvania-New Jersey-Maryland power pool)
PJM E	PJM Eastern Mid-Atlantic Area Council (New Jersey, Delaware, eastern Maryland)
PJM ROM	PJM Rest of Mid-Atlantic Area Council (eastern Pennsylvania, DC, eastern Maryland)
PJM ROR	PJM Rest of Region (northern Illinois, Ohio, western Pennsylvania, western Maryland, West Virginia, Virginia, eastern North Carolina)
SOCO	Southern Company plus other utilities in Georgia, Alabama, eastern Mississippi, western Florida
SPP N	Southwest Power Pool—North (Kansas, western Missouri)
SPP S	Southwest Power Pool—South (Oklahoma, north Texas, eastern New Mexico, western Arizona, western Louisiana)
TVA	Tennessee Valley Authority (Tennessee, northern Mississippi, northern Alabama, southern Kentucky)
VACAR	Virginia-Carolina Subregion—South Carolina, western North Carolina

EXECUTIVE SUMMARY

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. The US Department of Energy (DOE), which had sponsored the study, asked Oak Ridge National Laboratory researchers and others who worked on the project to conduct an additional study of the data to provide further insights for stakeholders and the industry.

The EI covers most of the electricity grid east of the Rockies. High voltage transmission lines interconnect the regions in the EI so power can be transferred readily between them. The EI consists of the multicolored (non-gold) regions in the map in Fig. ES-1. The regions used in the EIPC study (both EI and non-EI) are referred to as NEEM regions throughout this report because of the model (the North American Electricity and Environment Model) used for analysis in Phase 1 of the study. These NEEM regions are based on the boundaries of organizations such as utilities, regional transmission operators, coordinating authorities, independent system operators, and other natural groupings of the grid. Table ES-1 gives a more detailed description of each region in the EI.

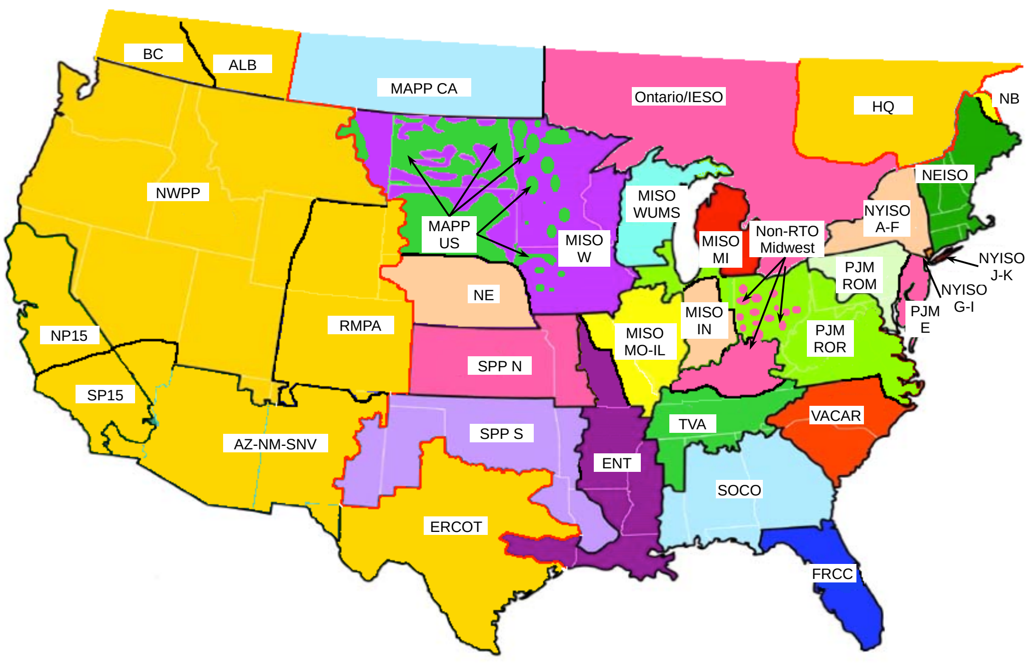


Fig. ES-1. Map of North American Electricity and Environment Model regions. (The Eastern Interconnection includes the multicolored, non-gold, regions).

For this report, results are presented at the level of the entire EI, the individual NEEM regions, or collections of NEEM regions into larger "territories" or "superregions" based on similar characteristics or transmission relationships.

Table ES-1. NEEM Regions, Superregions, and Territories in the Eastern Interconnection

Region	Description	Superregion	Territory
MAPP CA	Mid-Continent Area Power Pool (MAPP) Canada (Manitoba-Saskatchewan)	Midwest	Northwest
MAPP US	MAPP US (non-MISO regions in MT, ND, SD, MN, IA)	Midwest	Northwest
MISO W	Midcontinent Independent System Operator (MISO) in Michigan	Midwest	Northwest
MISO MO-IL	MISO Missouri-Illinois (eastern MO, much of IL)	Midwest	Northwest
MISO WUMS	MISO Wisconsin-Upper Michigan	Midwest	Northwest
MISO IN	MISO Indiana	Midwest	Northwest
MISO MI	MISO West (parts of MT, ND, SD, MN, IA, MN, WI)	Midwest	Northwest
Non-RTO Midwest	Non-RTO in Midwest (most KY, some OH)	Midwest	Central
PJM ROR	PJM Rest of Region (parts of IL, OH, PA, MD, WV, VA, NC)	PJM ROR	Central
PJM ROM	PJM Rest of Mid-Atlantic Area Council (parts of PA, MD, DC)	PJM MAAC	Central
PJM E	PJM Eastern MAAC (NJ, DE, east MD)	PJM MAAC	Central
IESO	Independent Electricity System Operator in Ontario	Ontario	Northeast
NYISO A-F	New York Independent System Operator (ISO) in Upstate NY	Northeast	Northeast
NYISO G-I	New York ISO in lower Hudson Valley	Northeast	Northeast
NYISO J-K	New York ISO in New York City-Long Island	Northeast	Northeast
NEISO	New England Independent System Operator	Northeast	Northeast
NE	Nebraska	Southwest	Southwest
SPP N	Southwest Power Pool (SPP) North (Kansas, western Missouri)	Southwest	Southwest
SPP S	SPP South (Oklahoma, north TX, east NM, west AR, west LA)	Southwest	Southwest
ENT	Entergy Corp. + other utilities in central MO, AR, LA, MS, east TX	Southwest	Southwest
TVA	Tennessee Valley Authority (TN, north MS, north AL, south KY)	Southeast	Southeast
SOCO	Southern Company + other utilities in GA, AL, east MS, west FL	Southeast	Southeast
VACAR	South Carolina, west North Carolina	Southeast	Southeast
FRCC	Florida minus panhandle	Southeast	Southeast

The Phase 1 analysis used a capacity expansion model belonging to Charles River Associates (CRA) called MRN-NEEM (Multi-Region National–North American Electricity and Environment Model). A capacity expansion model evaluates energy supply and demand over multiple decades and will build or retire capacity as needed or economic. The MRN-NEEM document on the EIPC website provides more detail on the models used (CRA 2010).

In Phase 1 of the 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 ES-2, along with a description and the short label used for each in this report.

Table ES-2. 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

A set of sensitivities was defined for each future, but first a base case using the general equilibrium economic model MRN had to be run to establish economy-wide, energy-related demands and prices. The results of these base cases could then be used to expand the transmission system between regions. Following that, other sensitivities allowed the EIPC and SSC to explore a variety of changes to technologies, costs, demands, or policies. Table ES-3 summarizes the different sensitivities analyzed.

Table ES-3. Main Sensitivities Studied in Phase 1

Sensitivities	Future 1: BAU	Future 2: CO_2/N	Future 3: CO_2/R	Future 4: EE/DR	Future 5: RPS/N	Future 6: RPS/R	Future 7: NUC	Future 8: CO_2+
Expand transmission	√	√	√		√	√	√	√
± Load growth	√	√	√		√	√	√	
± Gas price	√	√	√		√	√		√
± Renewable cost or deployment	√	√	√		√	√		√
Delay regulations	√							
CO_2 cost adjustment		√	√				√	√
PEV variations				√	√	√		
Extra EE savings				√				
Clean Energy Standard					√	√		
Small modular reactors							√	
Higher RPS limits								√

Three scenarios representing transmission needs under a broad array of hypothetical futures were selected for more extensive transmission-focused evaluation in Phase 2: a business as usual scenario (labeled BAU in this report); a scenario with a national renewable portfolio standard (RPS) that is implemented on a regional basis (labeled RPS/R here); and a combined policies scenario with a high CO_2 cost, a national RPS, and aggressive energy efficiency (EE)/demand response (DR)/distributed generation (labeled CO_2+ here).

In Phase 2 the EI was modeled at a very detailed level (70,000 buses, 9,900 generators) using the Power System Simulator for Engineering model for a peak hour and off-peak hour in each case (only the peak hour in the BAU case.) Transmission lines and other upgrades were added to ensure reliability criteria were met in those hours. The resulting build-outs of the transmission system in these scenarios were then used as inputs in the General Electric Multi-Area Production Simulation software (GE MAPS) model run by CRA. GE MAPS is a detailed economic dispatch and production cost model that simulates electric power system operation, taking into account transmission topology. The GE MAPS model projected energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors. Additional information regarding the EIPC modeling can be found in the EIPC Phase 1 Report (EIPC 2011), and the EIPC Phase 2 Report (EIPC 2012).

The results from Phases 1 and 2 provided a wealth of data that could be examined further to address energy-related questions. In January 2013, a small group of EIPC, EISPC, and SSC members were contacted to determine the need for additional analysis and topics of interest. Based on the responses a list of 13 study topics was developed, later supplemented with a 14th topic.

The first five topics were discussed in the report *Additional EIPC Study Analysis: Interim Report on High Priority Topics* (Hadley 2013). Topics 6–9 were analyzed in the report *Additional EIPC Study Analysis: Interim Report on Medium Priority Topics* (Hadley and Gotham 2014a). Topics 10–13 were analyzed in the report *Additional EIPC Study Analysis: Report on Low Priority Topics* (Hadley and Gotham 2014b).

The findings in each of these interim reports have been incorporated into this final report, along with the analysis of Topic 14.

Table ES-4. Topics Studied as Part of Analysis of Eastern Interconnection Planning Collaborative Cases

	Description
	High Priority Topics
1	How do Phase 2 results compare to Phase 1?
2	Were there significant changes in earlier years within various regions?
3	When all costs are integrated, how do results compare between scenarios?
4	Do some regions face overreliance on certain fuels or technologies?
5	What are the gas sector interrelationships in the different regions?
	Medium Priority Topics
6	How did regional operating and planning reserves definitions affect the results?
7	Why was there so much wind curtailment in the RPS/R and CO_2+ scenarios?
8	How much did demand response as defined in the models affect results?
9	What transmission lines were of value in all scenarios?
	Low Priority Topics
10	How did regional vs. national implementation of policies differ?
11	What were the impacts of load growth sensitivities on resource mix and cost?
12	What impacts were noticed from the environmental policy sensitivities?
13	What impacts were noticed from the technology sensitivities?
	EISPC Added Topic
14	What changes in key inputs and expected results occurred since the study began?

Topic 1: How do Phase 2 results compare to Phase 1?

Because Phase 2 was a more detailed look at the EI, it captured more of the complexities that a real system faces and modeled the system under a broader set of circumstances (variable generation and demands). As a consequence, it required additional capacity (for reliability) and costs were higher.

Capacity amounts for the total EI differed between 4% and 6% between the two phases depending on the scenario, with some NEEM regions showing Phase 2 increases greater than 10%. Some of the regional differences were due to manually improved placement of combustion turbines across the territories during Phase 2.

Generation amounts differed only slightly for the EI as a whole. There was greater regional variation because of differences in transmission modeling, hourly supply and demand variations, and reliability constraints for reserves. Several of the regions in the western EI had much lower Phase 2 generation in the CO_2+ scenario. This was likely due to the excess wind that had to be curtailed in many hours in those regions in the more detailed Phase 2 modeling.

Interregional transmission was quite different between some of the regions, especially in the CO_2+ scenario. The hourly modeling in Phase 2 (and the greater variation in wind generation) meant greater opportunities for transfers. In addition, there was a more explicit and accurate build-out and modeling of power flow in Phase 2 than Phase 1. The interregional maximum and average flows in Phase 2 were most different for the Western EI, again likely due to wind curtailment.

Total costs in Phase 2 for all of the EI were 16% higher than Phase 1 in the CO_2+ scenario but only 4% and 1% in the other two scenarios. Phase 2 had more precise (and generally higher) capital costs as the different EIPC members developed costs based on known projects; also, the phase had higher generating capacities. Generating plant capital costs heavily outweighed that of transmission. The difference in cost is most noticeable in the CO_2+ scenario in the high wind regions, MISO W, SPP N, and SPP S,* where wind capacity was highest (Fig. ES-2).

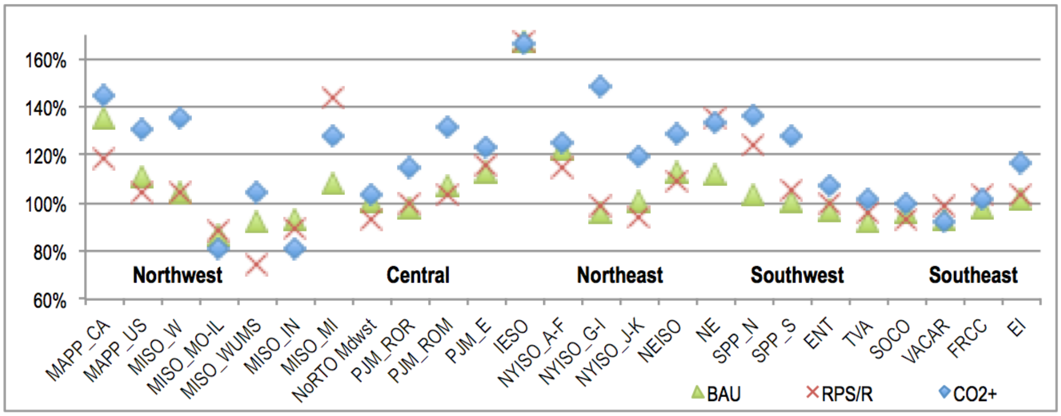


Fig. ES-2. Ratio of Phase 2 to Phase 1 generation costs in 2030 by region.

Topic 2: Were there significant changes in earlier years within various regions?

The study focused primarily on the results for the year 2030. In further examining the changes that took place from 2015 to 2025, the most consistent change across the regions was the large increase in DR expected by 2020 and 2025, especially in the CO_2+ scenario. Most regions also had a large decrease in capacity between 2010 and 2015, most often that of fossil-fired steam plants.

The CO_2+ scenario had the greatest change in all regions, as the carbon cost increased to high levels so carbon-based fuels declined (Fig. ES-3). Coal generation was the first to decline, often replaced with combined cycle (CC) or wind initially. In the later years, even CC plants decreased production in favor of nuclear or additional renewable generation.

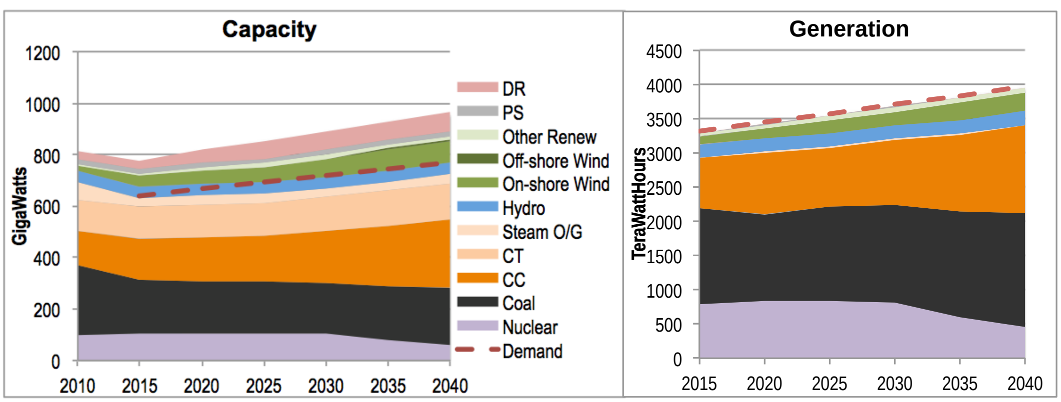


Fig. ES-3. CO_2+ scenario Phase 1 capacity and generation for the Eastern Interconnection (EI).

In the RPS/R Scenario, most changes were more gradual. Wind and other renewables were added as the RPS requirement increased. As in the CO_2+ scenario, large wind increases occurred somewhat sooner in the Southwest than Northwest. Offshore wind and other renewables provided almost all new capacity in

*Note: Refer to Table ES-1 or the Eastern Interconnection members/regions list at the front of this report for complete definitions of region identifiers used in the text.

the Southeast. The BAU Scenario had very few large changes in capacity and generation over time in the various territories.

Topic 3: When all costs are integrated, how do results compare between scenarios?

Costs evaluated included annual fuel and operating costs, emissions costs, levelized capital costs for generation and upgrades to transmission, and several other customer costs. Phase 2 only evaluated costs in 2030 rather than values over the full 30-year period. Costs were highest for the EI in the CO_2+ scenario (Fig. ES-4).

Some of this higher cost represented CO_2 emissions costs that either are intangible costs (and so available for other purposes) or are costs that should be included in other scenarios for comparison. Regardless, costs were still high for the CO_2+ scenario and the RPS/R scenario due to the large capital investment in new capacity. In contrast, fuel and other operating costs were much lower in the CO_2+ scenario.

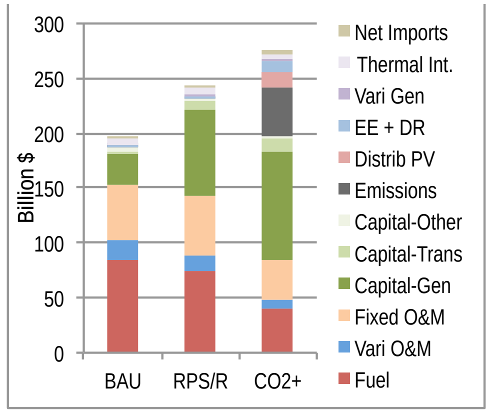


Fig. ES-4. Phase 2 total costs for the Eastern Interconnection (EI) in 2030.

Transmission cost represented only 10% of the overall capital cost, and less than 5% of total costs. It is likely that in those scenarios with high levels of curtailment and/or DR, additional transmission capacity would provide opportunities for lower cost power to displace high cost power.

Topic 4: Do some regions face overreliance on certain fuels or technologies?

Regions with a high reliance on a single fuel may be vulnerable to shortages. The CO_2+ scenario had the most regions with high levels of reliance on single technologies, with 10 regions relying on a single source for more than two-thirds of their generation. These regions were generally reliant on wind, hydro, or CC, so they could be vulnerable to intermittent shortages due to calm winds, long-term drought, or low gas supply issues. Only six regions in the RPS/R and BAU scenarios had high levels of reliance, with coal, which is less likely to be vulnerable to disruptions, playing a role in most of them.

Figure ES-5 shows the shift in dominant sources for each region when going from the BAU to the RPS/R and CO_2+ scenarios. Note that coal dominance in BAU and RPS/R often switches to wind in the CO_2+ scenario. Nuclear is relatively dominant in a number of regions, though rarely more than 50% of the total.

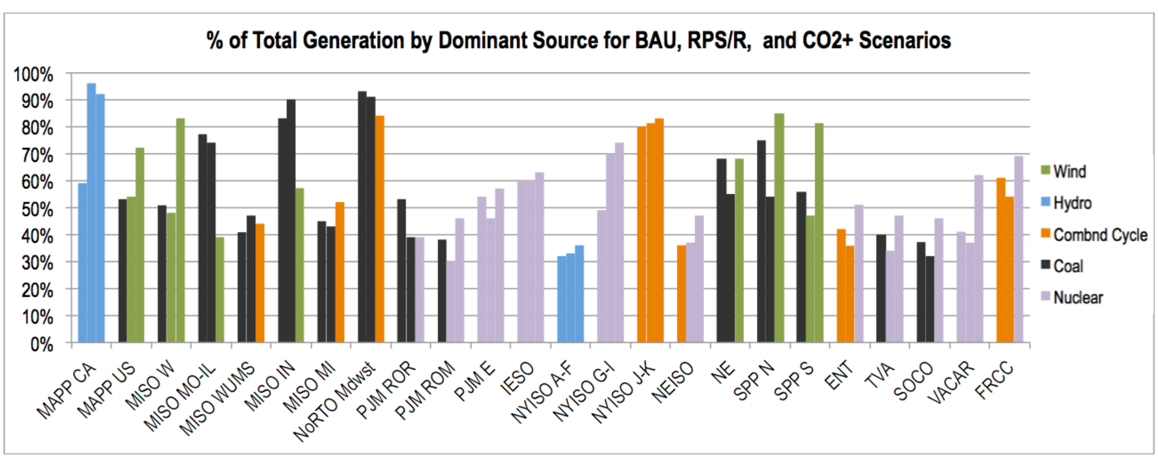


Fig. ES-5. Dominant generation source for each region and scenario.

Topic 5: What are the gas sector interrelationships in the different regions?

The study used gas prices from the DOE Energy Information Administration's (EIA's) 2011 *Annual Energy Outlook Early Release* (AEO; EIA 2011a), with a price of \$6.58 by 2030. Since then, estimates of prices in 2030 have dropped 20% or more. A possible consequence is that the study did not capture the level of conversion to natural gas that is now expected by many. The exception might be that in the CO_2+ scenario, even by 2015 total gas demand was 37% higher than in the BAU and RPS/R scenarios (Fig. ES-6) due to the relative cost impact of CO_2 emissions on coal versus gas generation.

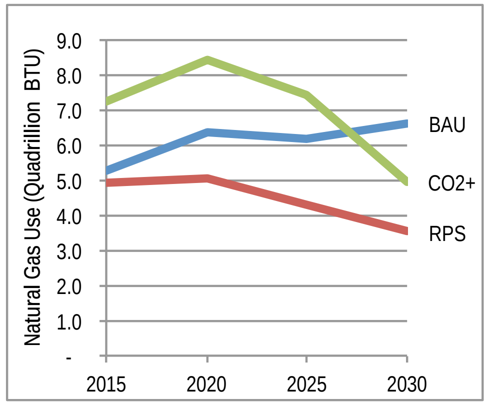


Fig. ES-6. Gas use for electricity.

Some regions showed dominance by gas, most notably NYISO J-K (and Non-RTO Midwest in the CO_2+ scenario). There did not appear to be a huge growth in gas demand between 2015 and 2030 for any region. Many regions saw declines between 2025 and 2030 in the CO_2+ scenario as CO_2 costs raised the cost of gas. Brief spikes in gas use appeared to hit the western regions most often. This only occurred in the CO_2+ and RPS/R scenarios, and these regions were not heavy users of gas so it is unlikely they would face critical shortages.

Topic 6: How did regional operating and planning reserves definitions affect the results?

Reserves represent an amount of capacity above demand available to provide adequate electricity at the correct voltage and frequency to maintain the grid under abnormal circumstances. Two main types of reserves were used in the EIPC study: planning reserves and operating reserves. Planning reserves were used for long-term resource planning, while operating reserves were used for day-to-day operations.

Phase 1 of the study used planning reserves, and all generating capacity could be used to meet the planning reserve margin, including DR. However, the EIPC derated intermittent (solar and wind) technologies by applying a fractional "resource contribution credit." This credit ranged from 11% to 30% depending on the region and technology. Because the capacity factors for these technologies were higher than the credit, there was often a large amount of extra generation from these intermittent sources, which affected the Phase 2 curtailment quantities discussed under Topic 7.

Figure ES-7 presents the capacities in each region as a fraction of their peak demands in the CO_2+ scenario. It shows both the technologies that qualify for the reserve calculation plus 100% of the intermittent capacity that is not fully credited. All regions meet their minimum reserve margins, but those with high wind capacity have significant capacity above internal reserve requirements available for export to other regions when wind production is high. Another observation is that the CO_2+ scenario included significant DR to meet reserve needs. Many regions required DR to meet their peak demand (the 100% line crosses DR in the chart) unless they could import from the regions with excess production.

Phase 2 considered operating reserves in the system modeling. In the modeling, only thermal fossil plants (coal, gas steam, and CC) and hydroelectric plants could provide reserves; these plants had to be running at least at their minimum dispatch points and could only provide limited quantities based on their ramp rates. While many regions had sufficient hydro to cover most of their reserves requirements, other regions were forced by their reserves requirements to increase output from the committed thermal units and DR while other lower-cost units (most notably wind) were curtailed. A Phase 2 sensitivity was run that cut the operating reserve requirement in half (to capture DR supply of reserves and enhanced CC flexibility). This led to a reduction in the amount of low cost power curtailed, as examined in Topics 7 and 8.

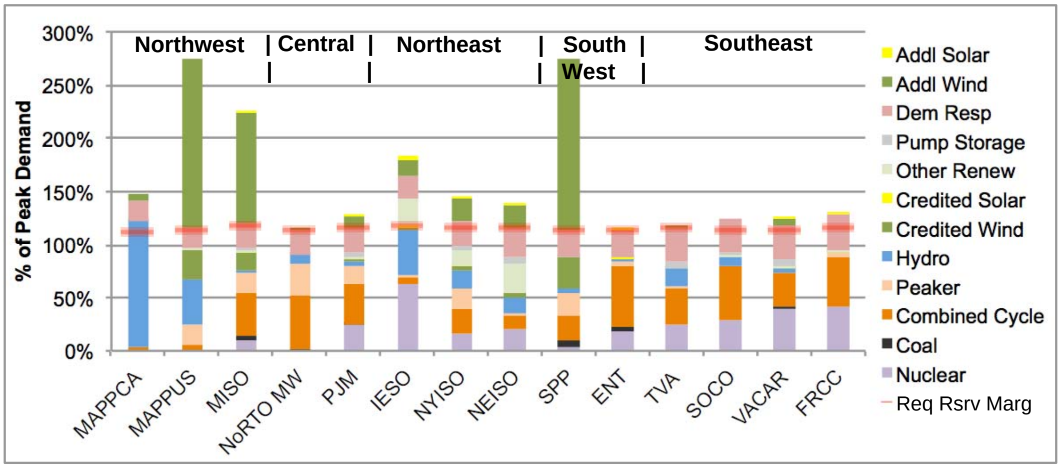


Fig. ES-7. Phase 1 ratio of capacities to peak demand in the CO_2+ scenario.

Topic 7: Why was there so much wind curtailment in the RPS/R and CO_2+ scenarios?

Wind power is a resource that can provide large amounts of electrical power at very low marginal cost. The variable operating cost is near zero, and when production tax credits are available the net variable cost to wind producers is actually negative. Generally, it is most economic for the sector to take all generation provided from wind. However, there are various reasons why at times the system cannot accept all the wind power available such as more production than consumers demand at the time; insufficient transmission to carry the power to other regions; or other factors such as local reserve requirements, transmission impedance, ramping limitations, and environmental regulations.

In Phase 1, there was little issue with curtailment, primarily for two reasons. First, the wind generation and loads were aggregated and averaged into just 20 periods to cover each year. Extremes of high wind generation and/or very low demand, when curtailment would be most pronounced, were not evaluated. Phase 2 provided a more detailed hourly view, resulting in large curtailments, most notably in the high wind regions of MISO and SPP in the CO_2+ scenario. Second, operating reserves, which could force higher cost generators to run instead of the wind generators, were not modeled in Phase 1 of the study.

We used the results from multiple Phase 2 scenarios with differing amounts of curtailment to create a close approximation of the hourly curtailments for the five regions with the highest levels of curtailment (MISO MO-IL, MISO W, NE, SPP N, and SPP S). Our analysis showed that curtailments were highest in the morning hours for each region (Fig. ES-8), which indicates that low demand levels played an important role in curtailments.

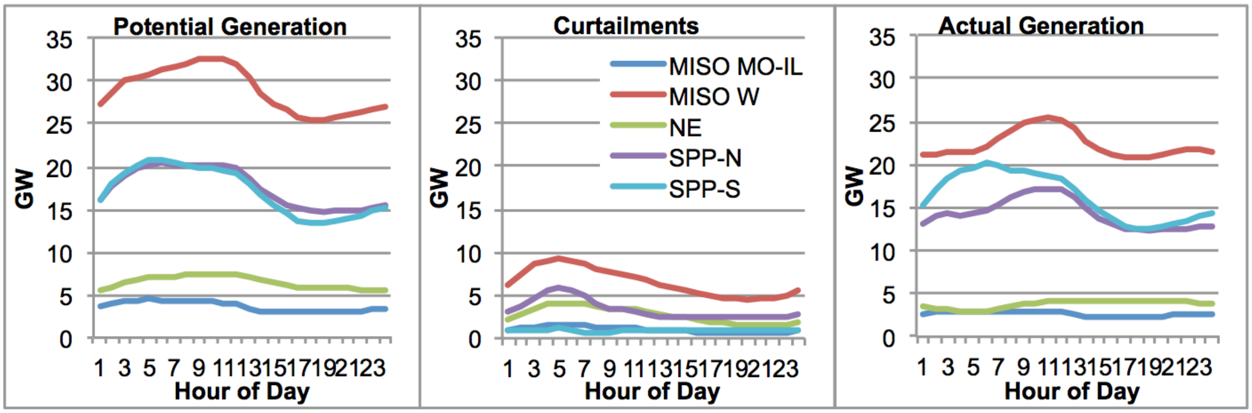


Fig. ES-8. Potential wind generation, curtailments, and actual generation in the CO_2+ scenario by hour of day. (Refer to Table ES-1 or the acronym list for region explanations.)

The peak curtailment day of April 1 was analyzed in depth (Fig. ES-9). The high curtailments at 4 a.m. occurred even though interregional tie-lines were not heavily loaded, so low demand must have played a role. Another factor was that CC production occurred, especially in PJM, despite prices below the cost of production, indicating that operating reserves played a role. When the flexibility of these CCs was increased in the "Hi Spin" sensitivity, CC production was greatly reduced in the early hours, resulting in more transfers from the windy regions and less curtailment.

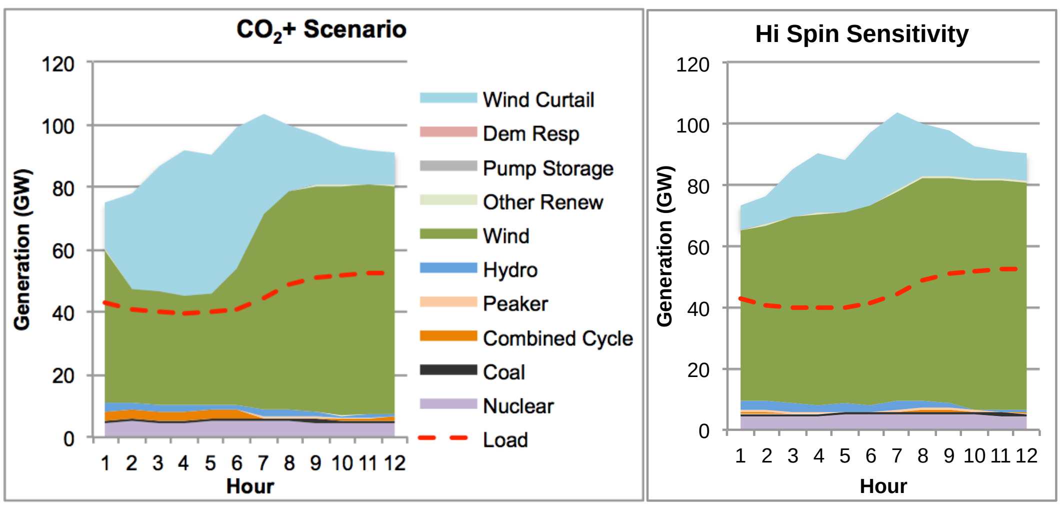


Fig. ES-9. Curtailed region April 1 morning generation levels in the CO_2+ scenario and Hi Spin sensitivity.

The modifications in the Hi Spin sensitivity reduced curtailments somewhat, but there were still many hours with large curtailments. Most of the curtailments, especially the high levels of curtailment, occurred when transfers from the region were near their peak amounts (Fig. ES-10). The red lines in Fig. ES-10 show the median values for net transfers and curtailments. Each point represents a different hour in the year. The vast majority of curtailed energy (94 TWh in the Hi Spin sensitivity) occurs in quadrant I when both curtailments and transfers are above the median, indicating that the dominant reason for the curtailments was the transfer limitations. However, more than 60 GW of additional transfer capacity (more than 17 high voltage direct current lines) would be required to ease the peak amount of curtailment shown in Fig. ES-10.

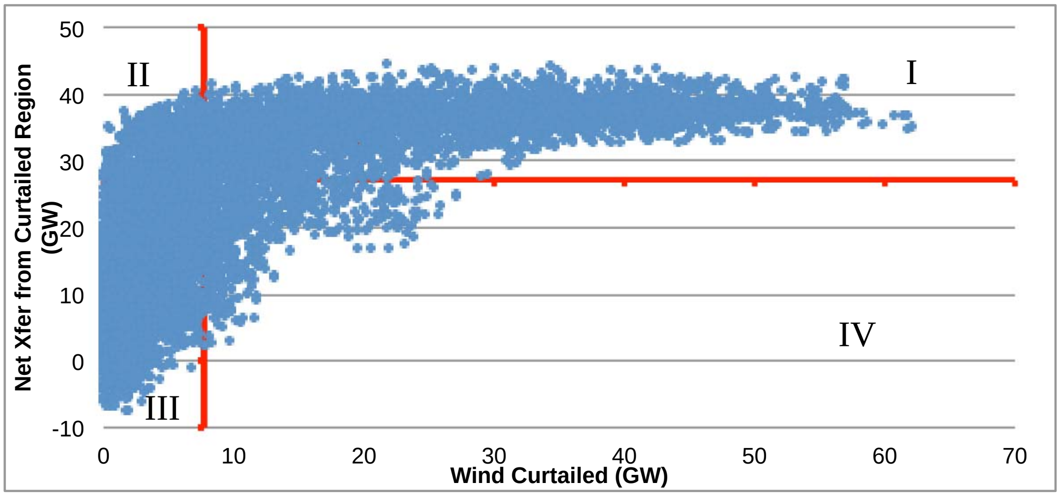


Fig. ES-10. Net transfer vs. wind curtailment in the curtailed regions in the Hi Spin sensitivity.

Topic 8: How much did demand response as defined in the models affect results?

DR is a complex collection of programs and technologies that allows demand to respond to supply, mainly through reduction of demand in the face of supply shortages. In June 2009, the Federal Energy Regulatory Commission (FERC) released a study on DR, *A National Assessment of Demand Response Potential* (FERC 2009), referred to in this report as the NADR. In the EIPC study, the amount of DR for each region was calculated using the state-by-state projections of DR across a combination of scenarios from the FERC NADR model.

In Phase I, the DR capacity was forced in as pseudo power plants at relatively high variable costs (price) to generate, $750/MWh, roughly the maximum amount from the FERC study. DR energy was dispatched in just the VACAR and FRCC regions, but DR capacity reduced the quantity of ordinary capacity needed to meet reserve requirements in all regions. In Phase 2, the SSC created a DR supply curve for each region based on the amounts used in Phase 1 and the FERC model. DR was called upon more frequently in this phase because variations in demands and supplies were greater than in Phase 1,leading to periods with insufficient conventional supplies. This was compounded by the reserve requirements that limited CC production during high demand.

DR use was more extensive in the Southeast: SOCO, VACAR, and FRCC. Lack of surplus renewables meant little cushion during peak times, as for example in the August 1 scenario depicted in Fig. ES-11. Operating reserve requirements also contributed as CC capacity had to be reduced during periods of peak demand to provide needed spinning reserves. If DR had been allowed to provide reserves, the CC capacity might have provided more power and reduced the need to call on DR energy.

The DR capacity was scattered across a region in line with the demands. Transmission congestion issues both within a region and between regions could cause DR to be called upon in some parts of a region but not in others. This can be seen in the different marginal prices reported by the balancing areas. Within VACAR, the areas within the southern part of South Carolina (Santee Cooper, Central Electric Coop, and SC Electric & Gas) called upon DR more often at higher levels, resulting in higher marginal prices than other areas in the region (in Fig. ES-12).

One question was why the Southeast did not build out more transmission capacity if it was going to be faced with more capacity issues than other regions. This can be partly explained because in the Phase 1 modeling the potential added transmission was only used during peak times, less than 20% of the year, and so did not meet the SSC usage criteria for these lines to be built. There could be several reasons why they were only used during peak times, including hurdle rates between regions or the “peakiness” in the Southeast, with higher summer demands.

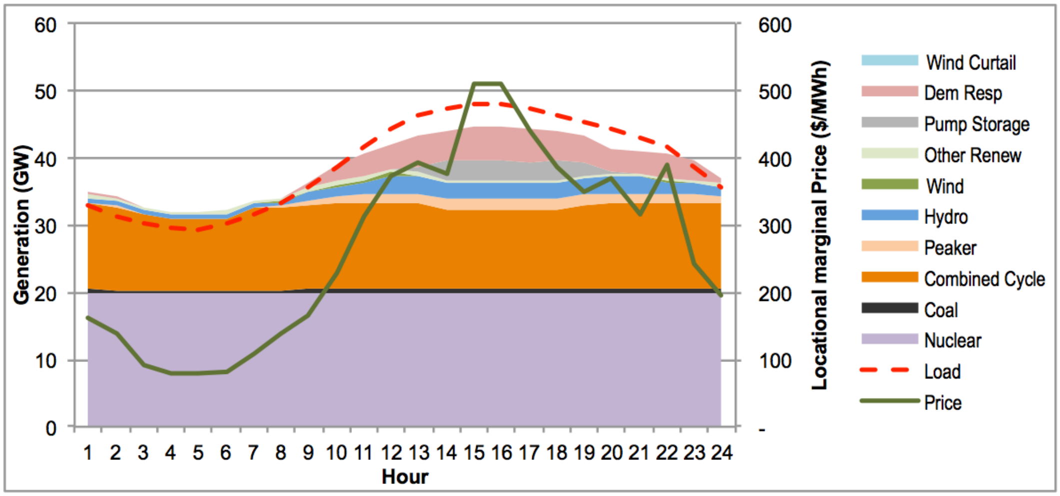


Fig. ES-11. VACAR generation, load, and marginal price on August 1 in the CO_2+ scenario.

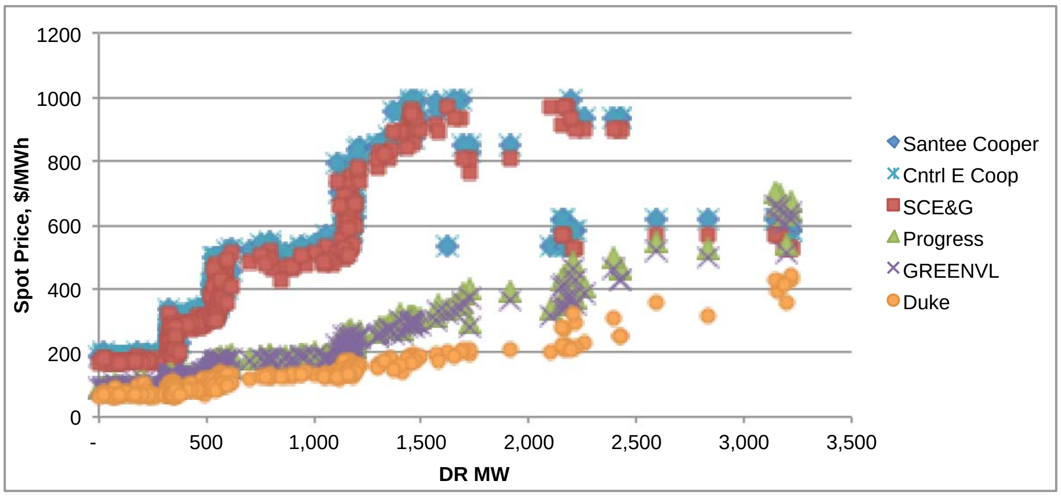


Fig. ES-12. Marginal prices at six balancing areas versus the corresponding demand response (DR) demand for all of VACAR in the business as usual scenario.

Topic 9: What transmission lines were of value in all scenarios?

Before any scenarios were run, a base transmission grid was defined, including both existing elements and new elements proposed by the EIPC and approved by the SSC. Each scenario then had elements (transmission lines, transformers, autotransformers, reactive support devices, or other upgrades) added as needed to interconnect new generation, prevent overloads, or prevent low voltage situations. Of these added elements, 89 were common to all three scenarios (Fig. ES-13). Many of these additions were in the NEISO region to support new wind farms that were added in the SSC process. In addition to these, there were 26 elements that were modified in all three scenarios, but in different ways (e.g., added circuit, reconductoring, or higher rating on new equipment).

Fig. ES-13. Locations of buses with upgrades common to all three scenarios.

Topic 10: How did regional vs. national implementation of policies differ?

During Phase 1, two sets of futures were used to examine the effects of using a national approach to policy issues versus a regional approach. The first set (Futures 2 and 3) examined the impact of a CO_2 cost assigned to emissions with transfer capacity increases allowed between superregions (the national implementation case, or "CO_2/N") versus a system with limited flows between superregions (the regional implementation case, or "CO_2/R"). Carbon dioxide prices for the two CO_2 futures were designed to lower economy-wide emissions from 2005 levels 42% by 2030 and 80% by 2050.

The second set (Futures 5 and 6) examined the implementation of national and regional RPSs, called RPS/N and RPS/R. The RPS in the two RPS futures required that 7.5% of overall energy in 2015 be generated from a renewable source, which is defined as biomass, geothermal, hydroelectric, landfill gas, solar, or wind. The RPS requirement increased over time to 30% in 2030.

For the CO_2 price futures, the regional implementation resulted in a significant drop in energy from renewables with a correspondingly large increase in energy from natural gas compared to the national implementation. Energy from coal and nuclear sources was also higher under the regional implementation. With the reduction in wind generation and increased generation from natural gas and coal, the regional implementation produced more CO_2 emissions.

Unlike the CO_2 price futures, the regional versus national implementation of an RPS had little impact on coal and natural gas use over the EI. The primary effect was that the regional implementation relied less heavily on wind from the Midwest and Southwest superregions and more heavily on offshore wind and biomass in the eastern portions of the EI. The regional CO_2/R future had greater CO_2 emissions than the national CO_2/N future, but at a slightly lower cost. The RPS/R future had higher overall costs than the RPS/N future.

Topic 11: What were the impacts of load growth sensitivities on resource mix and cost?

The base scenario of each future included electricity demand growth rates that were initially calculated by the EIPC members for their respective regions.

To examine the impact of growth, sensitivities were run on many of the futures, which either raised or lowered the growth rates. The rates were changed by adding or subtracting 1% to/from the annual rate; so for example, a growth rate of 0.85% became either 1.85% or −0.15% depending on the sensitivity. For every future, the transmission system was only expanded during development of the base scenario. Thus, there was little actual change in the amount the transmission grid was used despite the change in demand under high or low growth.

Figure ES-14 shows projected generation by technology for the EI in 2030 for the base case and sensitivities. Natural gas generation shifted the most of all technologies between the base and sensitivities for each future with variations up to +90% or −49% in the high or low load sensitivities. Renewable amounts change roughly in line with the total percentage change, while coal and nuclear generation change little.

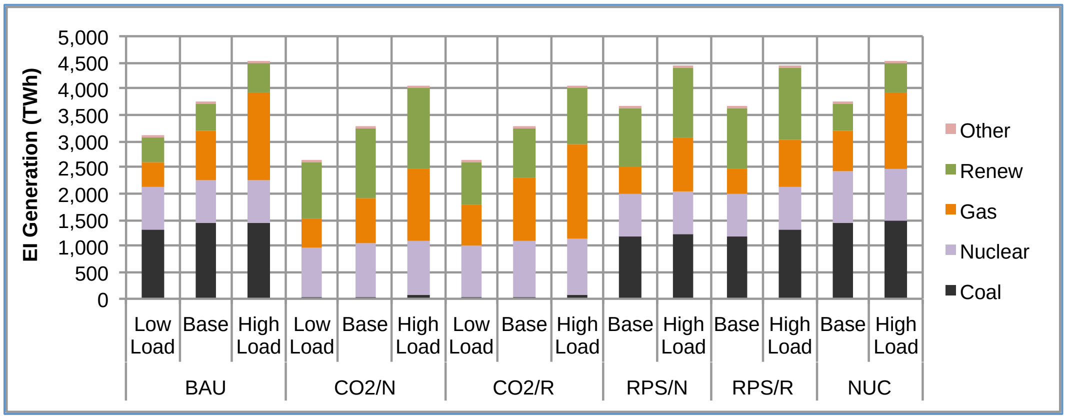


Fig. ES-14. Eastern Interconnection (EI) projected generation by technology in 2030 under different load growth scenarios.

Topic 12: What impacts were noticed from the environmental policy sensitivities?

High CO_2 costs greatly "decarbonized" the electric sector, especially post-2030. Lowering CO_2 prices by 20% reduced the amount of renewables and nuclear used, with gas-fired capacity increasing. Of all policies, CO_2 price additions, in conjunction with other factors such as lowered capital cost, most incentivized nuclear capacity increases

Reductions or delays in implementation of environmental policies generally increased the amount of coal-fired generation at the expense of gas or renewables. Reducing current state RPS, EE, and DR goals allowed the increase of both coal- and gas-fired generation, with a smaller reduction in renewables such that overall demand increased. Simple delays in implementation of current US Environmental Protection Agency (EPA) requirements increased coal-fired generation at the expense of natural gas-fired generation, while elimination of the Production Tax Credit and state RPS requirements lowered the renewable content in favor of coal and gas, even with high load growth.

On the other hand, more stringent environmental policies generally reduced the amount of fossil fuel–based generation through increases in EE, increases in the use of renewables, and/or DR (Fig. ES-15). Lifting the original ceiling on variable generation from a maximum of 35% to 50% only increased total renewable use by 3%–4% because only the central and southwest regions could take advantage of this raised ceiling. Increasing EE and DR programs resulted in lower fossil fuel generation rather than renewable generation.

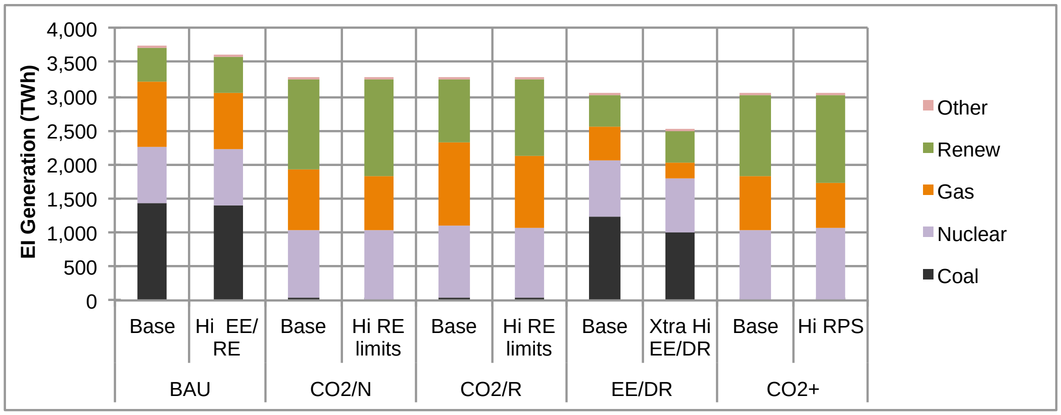


Fig. ES-15. Eastern Interconnection (EI) generation in 2030 by technology for increased environmental policy sensitivities.

The Clean Energy Standard was intermediary in its impact on carbon emissions between the base CO_2 and RPS cases. By setting a standard for all carbon-reducing technologies, there was a significant reduction in coal generation and carbon emissions without the impact of added CO_2 costs.

Topic 13: What impacts were noticed from the technology sensitivities?

A number of the sensitivities involved changes to the various technologies (e.g., price, cost, efficiency, or availability). Natural gas price sensitivities were included in this category because a main component of gas prices is the continued feasibility of hydrofracturing and sufficient transportation infrastructure.

The base case of each future resulted in generally different mixes of generation. Changing gas prices within each future had the expected effect: lower prices led to increased gas use while higher gas prices reduced gas-fired capacity and generation. Similarly, capital cost reductions for renewables resulted in increases in renewable capacity. Onshore wind was the main beneficiary of the lower costs, though in the CO_2/R future the lower costs also increased the offshore wind, photovoltaic (PV), and hydro capacities.

Plug-in electric vehicles could raise peak demands and consequent capacity requirements, with the impact strongly depending on the timing of the charging. If charging was predominantly at peak times, then the system peak would increase by 1.2 kW/vehicle. If charging was delayed to nighttime (such as through smart grid implementation), then the peak would only increase by 0.1 kW/vehicle. Marginal generation to meet the added demand came from natural gas, with some coal and renewables under the RPS futures.

Despite the lower capital cost, there was no change in the nuclear capacity built between the nuclear resurgence base and the small modular reactor sensitivity through 2030. Offshore wind capacity could be selected in all cases but was only selected in sensitivities with lower renewable capital costs or in the RPS future with regional response (RPS/R). In this study, the preferred location for offshore wind was in VACAR, followed by PJM E and then PJM ROM

Topic 14: What changes in key inputs and expected results occurred since the study began?

The input assumptions used in the EIPC study were formulated by stakeholders largely in the late 2010 to early 2011 time frame. These input assumptions are now roughly 4 years old, and this topic examines 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: Using 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. If everything else is 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 projections of PV solar capacity (EIA 2014) 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 EIPC study in 2030 was somewhat lower than today's EIA 2014 projections, certain EIPC study futures did capture the high range of solar capacity projected by EIA today.

Electricity Demand: The projected energy demand used in the EIPC study for the first 10 years was largely from the individual planning authorities for each region, while later years used the growth rates from the AEO 2011. Projected energy demands for 2011 were relatively the same in the BAU scenario and AEO 2011, differing just 0.7%. But the utility estimates for growth between 2011 and 2015 in the BAU scenario were an annualized 1.2%, 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 totals of around 4% for the study period. The projected demands from the AEO 2014 are even slightly lower than the AEO 2011 so that the BAU scenario 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 larger effect. A number of Phase 1 sensitivities result in significant reductions in CO_2 emissions, but none of them are 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 and an increase in renewables and natural gas is a likely outcome.

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. The US Department of Energy (DOE), which had sponsored the study, asked Oak Ridge National Laboratory (ORNL) researchers and others who had worked on the project to conduct an additional study of the data to provide further insights for stakeholders and the industry. This report documents the results of that study, including the results of earlier studies that provided interim results (Hadley 2013; Hadley and Gotham 2014a; Hadley and Gotham 2014b).

The EI covers most of the electricity grid east of the Rockies. High voltage transmission lines interconnect the regions in the EI so power can be transferred readily between them. The EI consists of the multicolored (non-gold) regions in the map in Fig. 1. The regions used in the EIPC study (both EI and non-EI) are referred to as NEEM regions throughout this report because of the model (the North American Electricity and Environment Model) used for analysis in Phase 1 of the study. These NEEM regions are based on the boundaries of organizations such as utilities, regional transmission operators (RTOs), coordinating authorities, independent system operators, and other natural groupings based on the structure of the grid. Table 1 gives a more detailed description of each region in the EI.

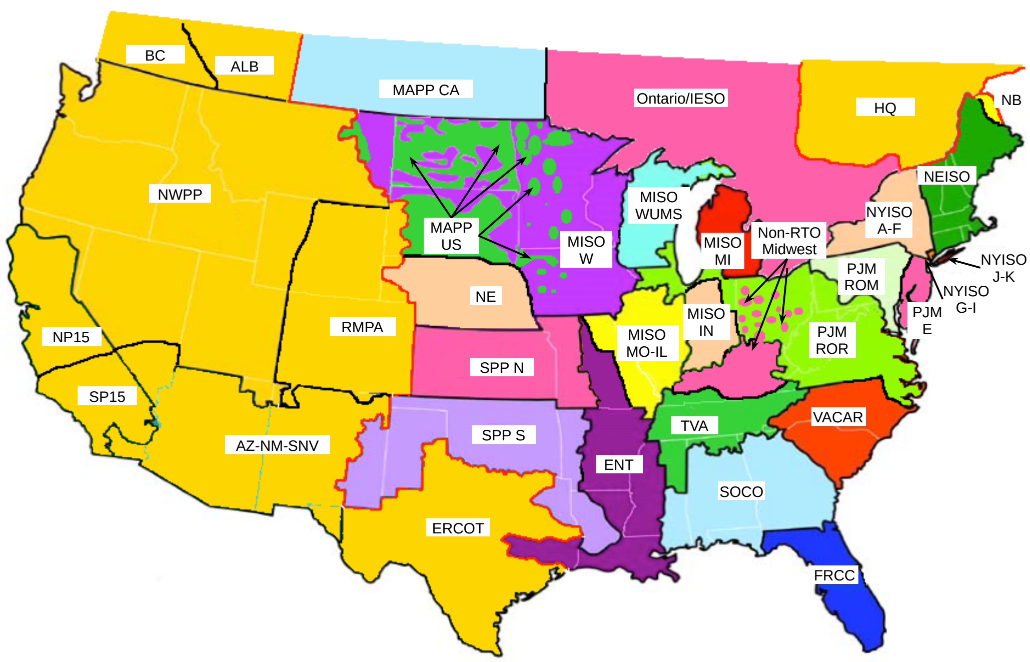


Fig. 1. Map of North American Electricity and Environmental Model regions. (The Eastern Interconnection includes the multicolored, non-gold, regions.)

For this report, results are presented at the level of the entire EI, the individual NEEM regions, or collections of NEEM regions into larger territories or superregions based on transmission relationships. The two larger groupings, territory and superregion, are slightly different. The five territories are larger groupings for reporting purposes only. The seven superregions split PJM[*] into two different superregions and include a separate superregion for IESO (Ontario). Also, the Non-RTO Midwest is in the Central territory with PJM but in the MISO superregion.

Table 1. NEEM Regions, Superregions, and Territories in the Eastern Interconnection

Region	Description	Superregion	Territory
MAPP CA	Mid-Continent Area Power Pool (MAPP) Canada (Manitoba-Saskatchewan)	Midwest	Northwest
MAPP US	MAPP US (non-MISO regions in MT, ND, SD, MN, IA)	Midwest	Northwest
MISO W	Midcontinent Independent System Operator (MISO) in Michigan	Midwest	Northwest
MISO MO-IL	MISO Missouri-Illinois (eastern MO, much of IL)	Midwest	Northwest
MISO WUMS	MISO Wisconsin-Upper Michigan	Midwest	Northwest
MISO IN	MISO Indiana	Midwest	Northwest
MISO MI	MISO West (parts of MT, ND, SD, MN, IA, MN, WI)	Midwest	Northwest
Non-RTO Midwest	Non-RTO in Midwest (most KY, some OH)	Midwest	Central
PJM ROR	PJM Rest of Region (parts of IL, OH, PA, MD, WV, VA, NC)	PJM ROR	Central
PJM ROM	PJM Rest of Mid-Atlantic Area Council (parts of PA, MD, DC)	PJM MAAC	Central
PJM E	PJM Eastern MAAC (NJ, DE, east MD)	PJM MAAC	Central
IESO	Independent Electricity System Operator in Ontario	Ontario	Northeast
NYISO A-F	New York Independent System Operator (ISO) in Upstate NY	Northeast	Northeast
NYISO G-I	New York ISO in lower Hudson Valley	Northeast	Northeast
NYISO J-K	New York ISO in New York City-Long Island	Northeast	Northeast
NEISO	New England Independent System Operator	Northeast	Northeast
NE	Nebraska	Southwest	Southwest
SPP N	Southwest Power Pool (SPP) North (Kansas, western Missouri)	Southwest	Southwest
SPP S	SPP South (Oklahoma, north TX, east NM, west AR, west LA)	Southwest	Southwest
ENT	Entergy Corp. + other utilities in central MO, AR, LA, MS, east TX	Southwest	Southwest
TVA	Tennessee Valley Authority (TN, north MS, north AL, south KY)	Southeast	Southeast
SOCO	Southern Company + other utilities in GA, AL, east MS, west FL	Southeast	Southeast
VACAR	South Carolina, west North Carolina	Southeast	Southeast
FRCC	Florida minus panhandle	Southeast	Southeast

The Phase 1 analysis used a capacity expansion model belonging to Charles River Associates (CRA) called MRN-NEEM (Multi-Region National–North American Electricity and Environment Model). A capacity expansion model evaluates energy supply and demand over multiple decades and builds or retires capacity as needed or economic. The MRN-NEEM document on the EIPC website provides more detail on the models used (CRA 2010). The following are some of the key characteristics of the Phase 1 modeling.

- Each region was treated as a single point or "bubble," with no transmission modeled internally.
- Each region was connected to other regions by single "pipes" for transferring electricity rather than physical transmission lines operating at different voltages.
- Transfer capacities between regions were initially calculated by the EIPC; however, a method was created to use model results to determine how much to expand the capacity in the different scenarios.
- The model calculated the supply, demand, and consequent generation capacity needed for each 5-year point between 2010 and 2050; however, only results for 2015–2040 were reported.

[*]Note: Refer to Table 1 or the Eastern Interconnection members/regions list at the front of this report for complete definitions of region identifiers used in the text.

- The model attempted to minimize costs over the period, taking into account various reliability and policy constraints such as minimum reserve margins and environmental regulations.
- The hours of each year were aggregated into 20 blocks of different duration: 10 blocks covered the summer hours, while 5 blocks each covered the winter and "shoulder" seasons.

CRA and the EIPC members formulated some of the initial inputs for the model, with final values determined by the SSC. This group pulled in information from utilities, DOE sources, and others to establish such factors as growth rates, cost projections, technology changes, etc. The inputs to and outputs from the model are available on the EIPC website (http://www.eipconline.com/). In addition, the EIPC prepared preliminary estimates of the cost of transmission expansion under each of the scenarios. Results of the Phase 1 analysis are in the EIPC Phase 1 Report (EIPC 2011).

In Phase 1 of the study the term "futures" was used to define a consistent set of input assumptions for technologies, policies, and costs. Eight futures were defined by the SSC in an attempt to cover a wide range of possible policies. The futures explored ranged from business as usual (BAU) to various CO_2 limits, renewable portfolio standards (RPSs), end-user activities, and nuclear resurgence (NUC). The eight are listed in Table 2, along with a description and the short label used for each in this report.

Table 2. 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

A set of sensitivities was defined for each future, but first a base case using the general equilibrium economic model MRN had to be run to establish economy-wide, energy-related demands and prices for each of the futures. The results of these base cases could then be used to expand the transmission system between regions. Following that, other sensitivities allowed the EIPC and the SSC to explore a variety of changes to technologies, costs, demands, or policies. Table 3 summarizes the different sensitivities analyzed.

Future 1 was the BAU scenario. It had 17 sensitivities that were used to establish the transmission build-out and explore the effects of gas prices, renewable costs, delayed implementation of environmental policies, and other factors. The final scenario in that group, Future 1 Scenario 17 or F1S17, was used as the basis for the BAU scenario in Phase 2. Futures 2 and 3 examined the impact of raising the cost of CO_2 to lower the level of CO_2 emissions from all sectors of the economy to 80% of 2005 levels by 2050, with an intermediate value of 42% by 2030. The distinction between them was the amount of interregional cooperation and transfer capacity within EI. Future 4 examined the effect of more aggressive energy efficiency (EE), demand response (DR), and distributed generation (DG). Because it reduced demand, there was no need to expand the transmission grid.

Futures 5 and 6 examined a national RPS with different levels of interregional cooperation. The second, Future 6, had only regional implementation, meaning each larger group of regions (each superregion) was responsible for meeting its RPS requirements, and transmission capacity was not expanded between these superregions to assist. There were 10 sensitivities in this future, and the final one, F6S10, was used for

Phase 2. Future 7 examined the potential for nuclear expansion based on lower costs for nuclear and other factors; a base and four sensitivities were examined. Future 8 was the final future of Phase 1 and combined both the CO_2 costs from Future 2 with the aggressive EE-DR-DG expansion from Future 4 and the RPS from Future 5. Seven sensitivities were included in Future 8 with F8S7 used in Phase 2.

Table 3. Main Sensitivities Studied in Phase 1

Sensitivities	Future 1 BAU	Future 2 CO_2/N	Future 3 CO_2/R	Future 4 EE/DR	Future 5 RPS/N	Future 6 RPS/R	Future 7 NUC	Future 8 CO_2+
Expand transmission	√	√	√		√	√	√	√
± Load growth	√	√	√		√	√	√	
± Natural gas prices	√	√	√		√	√		√
± Renewable cost or deployment	√	√	√		√	√		√
Delay regulations	√							
CO_2 cost adjustment		√	√				√	√
PEV variations				√	√	√		
Extra EE savings				√				
Clean Energy Standard					√	√		
Small modular reactors							√	
Higher RPS limits								√

Three scenarios, representing transmission needs under a broad array of hypothetical futures (or “bookends”), were selected for more extensive transmission-focused evaluation in Phase 2. The EI was modeled at a very detailed level (70,000 buses, 9,900 generators) using the Power System Simulator for Engineering (PSS/E) model for a peak hour and off-peak hour in each case (only the peak hour in the BAU case). Transmission lines and other upgrades were added to ensure reliability criteria were met in those hours. The resulting build-outs of the transmission system in these scenarios were then used to model the EI in the General Electric Multi-Area Production Simulation software (GE MAPS) model run by CRA. GE MAPS is a detailed economic dispatch and production cost model that simulates electric power system operation, taking into account transmission topology, to predict energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors. Results from the GE MAPS cases (hourly and annual results for the year 2030) were released to stakeholders. In addition, the EIPC and the SSC calculated costs for transmission and generation capital costs and other costs not calculated in GE MAPS. Following are some of the key characteristics of the Phase 2 modeling phase.

- The transmission build-out with PSS/E used an hour from Block 1 (peak summer) and an hour from Block 13 (mid-shoulder), using the average expected wind generation for each block.
- Transmission lines and substations were added during the build-out, primarily to meet reliability concerns; cost optimization was not a factor except indirectly through engineering judgment on line placement.

- GE MAPS modeled the system chronologically for the 8,760 hours of 2030, incorporating CRA estimates of wind patterns for the different regions.
- Operating reserves rather than planning reserves were modeled; technologies to meet reserve requirements were more restrictive than in Phase 1 and limited to coal, combined cycle (CC), and hydro units.

In Phase 2 the nomenclature for cases changed. The EIPC focused first on building out the transmission for the CO_2+ future. Consequently, it was called Scenario 1. Four sensitivities were run on the scenario to examine questions surrounding the amount of wind curtailment that occurred in the base case. The RPS/R (RPS implemented regionally) future was chosen as the second one to examine in Phase 2 and so was called Scenario 2, with no sensitivities run for it. The BAU future was the last to be examined and so was called Scenario 3. Two sensitivities were run for it: higher gas prices and higher demands.

The mixture of futures, sensitivities, and scenarios, with different nomenclature, has caused some confusion during the process. While many cases and scenarios were analyzed, the final results discussed in this report were derived based on three main scenarios. Brief descriptions of the three follow, including the names of the cases from the two different phases and the labels used in the follow-on reports.

- **Business as Usual**
  - Labeled BAU
  - Future 1 Sensitivity 17 (F1S17) in Phase 1
  - Scenario 3 (S3) in Phase 2
  - A continuation of current trends, policies, laws, and regulations
- **National Renewable Portfolio Standard Implemented Regionally**
  - Labeled RPS/R
  - Future 6 Sensitivity 10 (F6S10) in Phase 1
  - Scenario 2 (S2) in Phase 2
  - A national RPS of 30% by 2030, with regional implementation
- **Combined CO_2 + RPS + EE-DR-DG**
  - Labeled CO_2+
  - Future 8 Sensitivity 7 (F8S7) in Phase 1
  - Scenario 1 (S1) in Phase 2
  - Also called “Combined Policies” in some reporting
  - A combination of a high CO_2 cost, ~$140/metric ton CO_2; national RPS of 30%; and aggressive energy efficiency, demand response, and distributed generation expansion

The results from Phase 1 and Phase 2 provided a wealth of data that could be examined further to address energy-related questions. In January 2013, a small group of EIPC, EISPC, and SSC members were contacted about possible additional analyses and what topics would be of most interest. Based on feedback from this group, a list of 13 potential study topics was developed, which the group categorized as high, medium, or low priority and then ranked within these categories (Table 4). Order in the ranking was determined in such a way that earlier, lower numbered, items contribute to later items within the same category.

Table 4. Topics to Be Studied as Part of Analysis of Eastern Interconnection Planning Collaborative Cases

	Description
	High Priority Topics
1	How do Phase 2 results compare to Phase 1?
2	Were there significant changes in earlier years within various regions?
3	When all costs are integrated, how do results compare between scenarios?
4	Do some regions face overreliance on certain fuels or technologies?
5	What are the gas sector interrelationships in the different regions?
	Medium Priority Topics
6	How did regional operating and planning reserves definitions affect the results?
7	Why was there so much wind curtailment in the RPS/R and CO_2+ scenarios?
8	How much did demand response as defined in the models affect results?
9	What transmission lines were of value in all scenarios?
	Low Priority Topics
10	How did regional vs. national implementation of policies differ?
11	What were the impacts of load growth sensitivities on resource mix and cost?
12	What impacts were noticed from the environmental policy sensitivities?
13	What impacts were noticed from the technology sensitivities?
	EISPC Added Topic
14	What changes in key inputs and expected results occurred since the study began?

This report collects the results from previous interim reports plus a discussion of the last topic. Each chapter covers a separate topic. The first five topics were previously discussed in the report *Additional EIPC Study Analysis: Interim Report on High Priority Topics* (Hadley 2013). The second set of topics was analyzed in the report *Additional EIPC Study Analysis: Interim Report on Medium Priority Topics* (Hadley and Gotham 2014a). The third set of topics was covered in the report *Additional EIPC Study Analysis: Report on Low Priority Topics* (Hadley and Gotham 2014b).

1. TOPIC 1: PHASE 1 VS. PHASE 2 COMPARISON

The Phase 1 and Phase 2 analysis processes were described in the introduction. The first questions that arose following the study were related to whether the results from the two phases were so different as to cause people to question the results. Were data faithfully transferred between the two? Were differences in results explainable? How did differences in geography, time, and electrical system modeling influence the results? The sections below compare the results of Phase 1 and Phase 2 for power plant capacity, generation, interregional transmission, and costs.

1.1 Capacity

Figure 2 shows the total capacity in 2030 estimated in Phase 2. The RPS/R scenario has the largest overall capacity, largely because wind technologies were only credited at a fraction of their full capacity for purposes of determining reserve margins so more was needed to meet the minimum. While the CO_2+ scenario has more wind than the RPS/R scenario, its overall demands were less so the total required was lower. In the CO_2+ scenario, DR and wind are more significant fractions of capacity, while peaking plants are reduced and coal is practically eliminated. The corresponding graphs for each region are included in Appendix A.

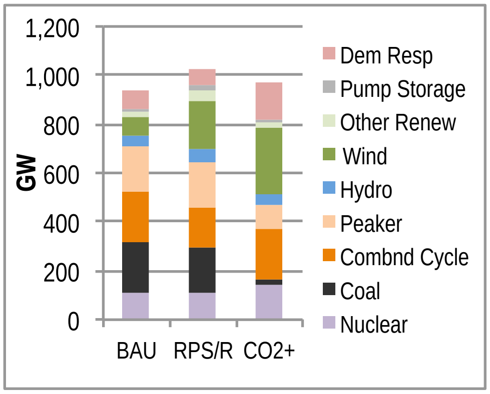


Fig. 2. Eastern Interconnection capacity estimated in Phase 2.

While the totals for generating capacity in most regions in Phase 1 and Phase 2 are close, more often the amounts are somewhat higher in Phase 2 than Phase 1. This is possibly due to a combination of higher capacities needed to meet ancillary services (reserves) requirements and incomplete deactivation of existing plants when transferring data from Phase 1 to Phase 2. Figure 3 shows the ratio of total capacity between the two phases. The ratio is greater than 100% for many regions, most notably for Entergy, MISO W, PJM E, and IESO. On the other hand, MISO WUMS has a ratio of only 62%, but just in the RPS/R scenario. This occurs because in Phase 1, a large number of combustion turbines (CTs) was added for MISO as a whole, but all were added in MISO WUMS by NEEM because capital costs were slightly lower there. The NEEM model did not use them for production, so there was no impact on generation-related costs. In the final steps of Phase 1, these CTs were scattered across the territory more realistically in the CO_2+ and BAU scenarios, but not RPS/R (because a final sensitivity run was not needed for that case.) So most of the MISO variations in RPS/R are simply the result of movement of CTs from MISO WUMS to the rest of MISO in Phase 2.

The next set of graphs, Figures 4–6, shows the actual amounts of capacity in 2030 for each region by technology. Some regions show slight differences in capacity between the two phases, mainly in coal, wind, and peaking plant technologies. Also, each bar in the figures shows the level of peak demand for the region in 2030. Regions generally should have sufficient capacity to cover peak demands plus a planning reserve of ~15%. Those with high wind capacity show a much greater capacity than demand, but this is because wind (and solar) contributions to reserves were only credited at 12% to 30% of their capacity. All regions have sufficient capacity to cover demands except the downstate New York regions because they rely on firm imports for a portion of capacity.

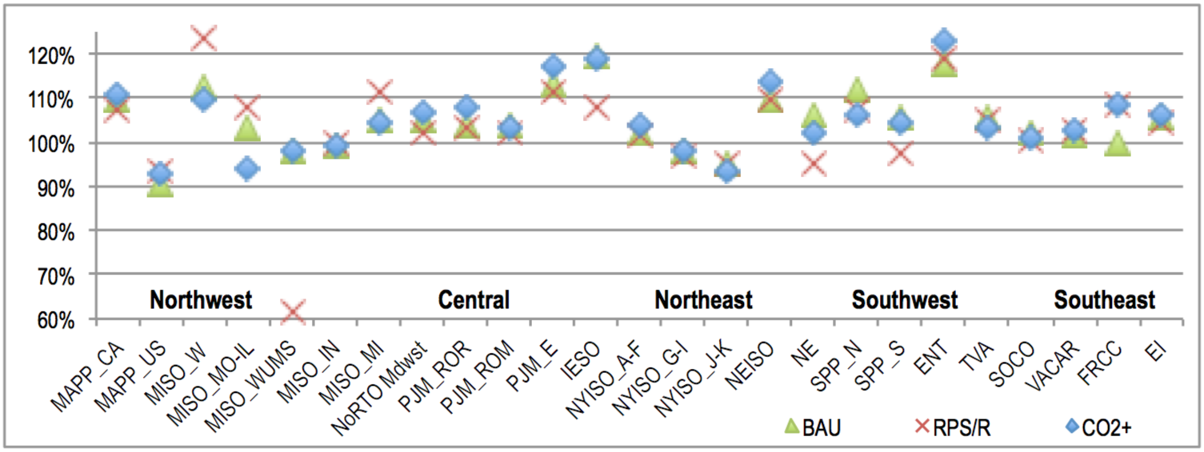


Fig. 3. Ratio of Phase 2 to Phase 1 capacity.

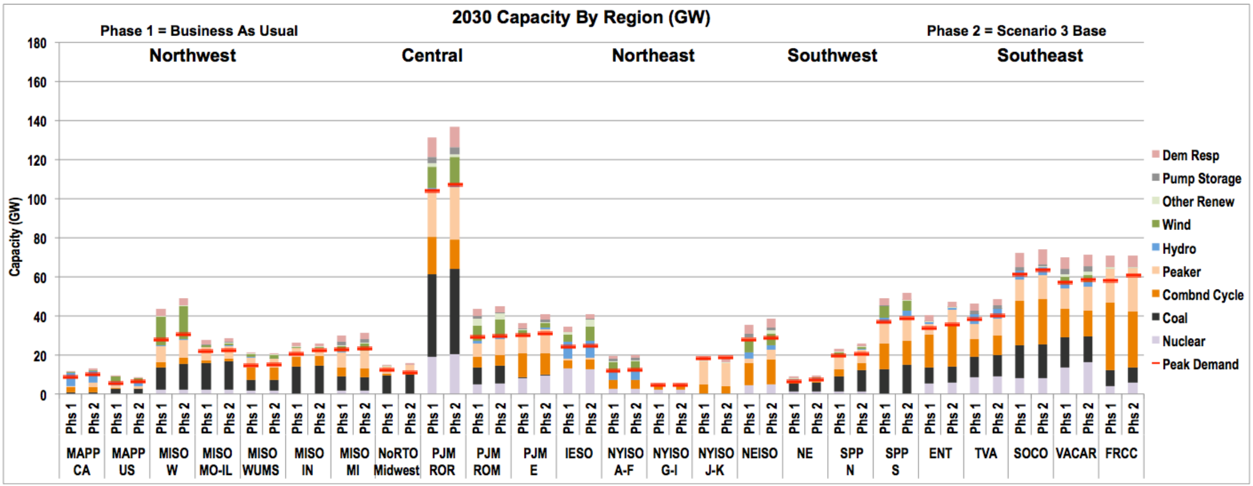


Fig. 4. Capacity amounts by region in 2030 in the BAU scenario. (Red rules/marks on the bars indicate the levels of peak demand in 2030.)

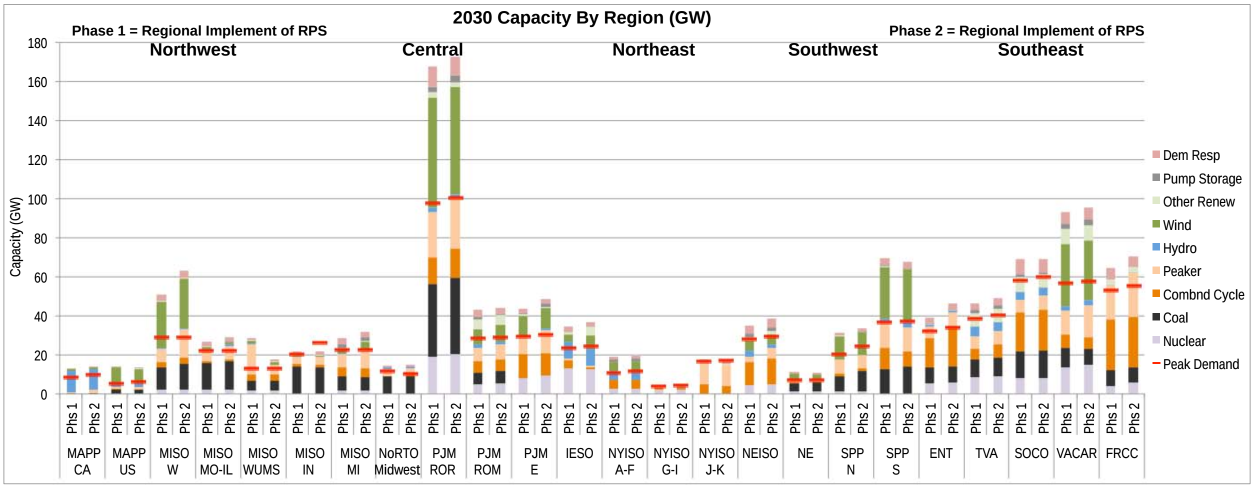


Fig. 5. Capacity amounts by region in 2030 in the RPS/R scenario. (Red rules/marks on the bars indicate the levels of peak demand in 2030.)

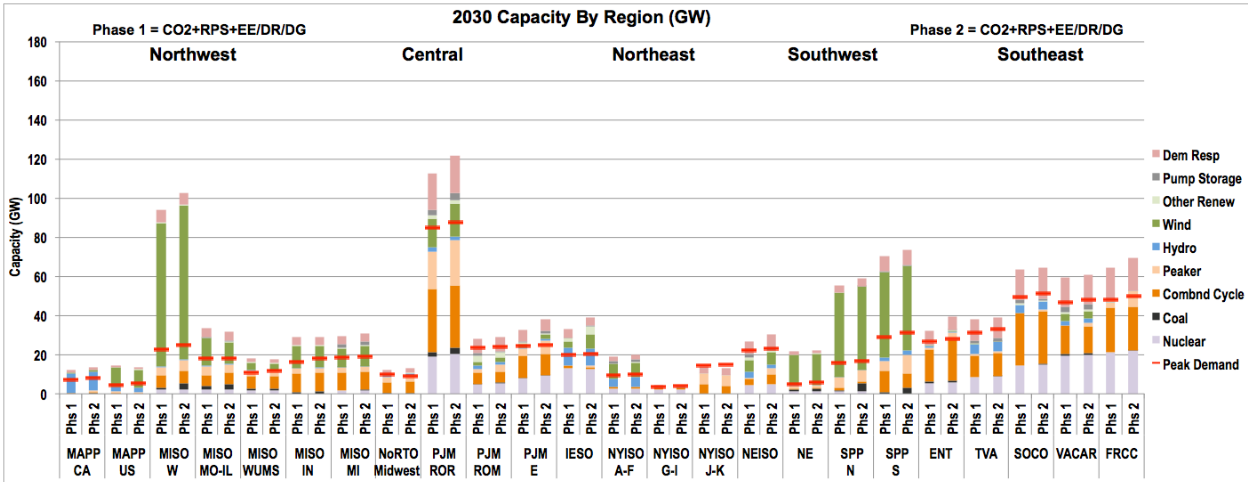


Fig. 6. Capacity amounts by region in 2030 in the CO_2+ scenario. (Red rules/marks on the bars indicate the levels of peak demand in 2030.)

1.2 Generation

Figure 7 shows the total 2030 generation estimated in Phase 2. As expected, the BAU scenario has the highest generation. The RPS/R scenario did not explicitly have lower load growth but had lower demand due to higher electricity prices in the MRN-NEEM model. In the CO_2+ scenario, demand was explicitly reduced to represent EE and DG effects. Wind generation was highest in the CO_2+ scenario, and coal generation was almost eliminated. Combined cycle plants were used to provide flexible generation and reserves, while nuclear grew, largely in Florida. The corresponding graphs for each region and territory are included in Appendix A.

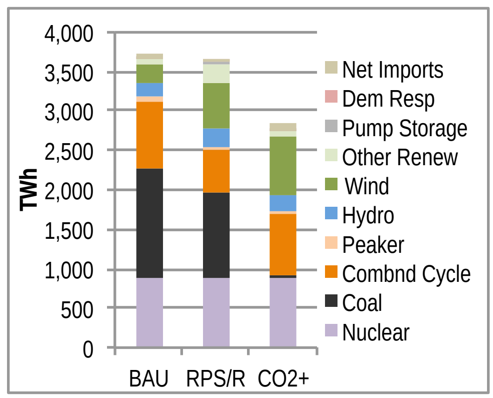


Fig. 7. Eastern Interconnection generation estimated in Phase 2.

As with capacity, the generation amounts in Phase 1 and Phase 2 for most regions are very similar. This is shown in Fig. 8 as the ratio of generation in Phase 2 to Phase 1 for each region, where 100% means they match exactly. If the values are similar this indicates that the models in the two phases dispatched the generation similarly, and so the modeling in the two phases and the transfer of results between phases was generally accurate.

A number of regions (MAPP US, MISO MO-IL, MISO IN, PJM ROR) show lower generation in Phase 2, indicated by ratios below 100%, with countervailing increases in other regions (PJM E, NYISO J-K, NEISO). This is likely due to the improved modeling of the grid in Phase 2, with more detailed representation of power flow and hourly variation versus the 20 power blocks used in Phase 1. Three factors are involved in the improved modeling. Power flows on transmission follow the paths of least resistance so may take routes that could lead to overloads unless amounts are reduced. Wind generation on an hourly basis will fluctuate more so may not be available when it could be transmitted. And limits on technologies providing operating reserves force some plants to operate within a region despite cheaper power available over transmission. Note that the ratios are highest or lowest in the CO_2+ scenario, which involved the most interregional transmission.

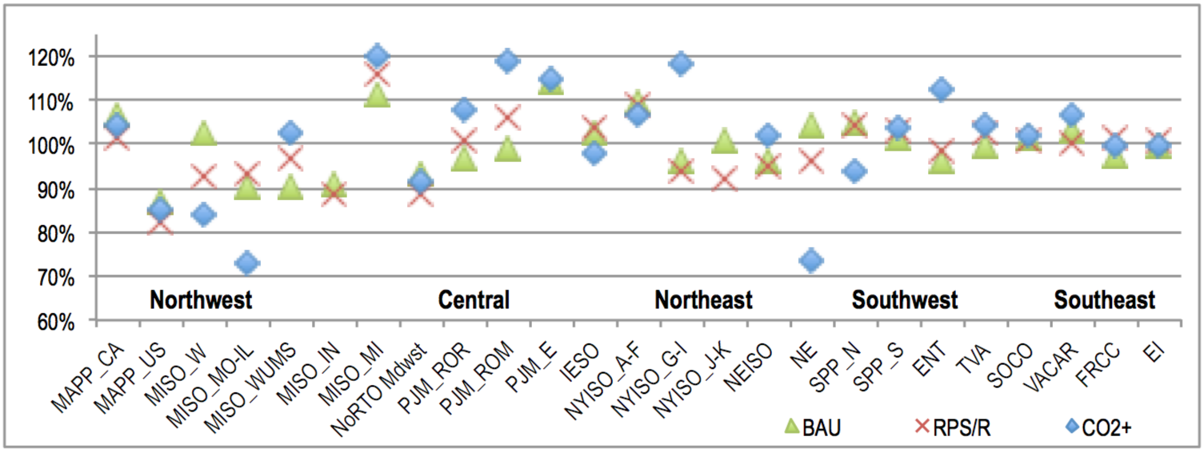


Fig. 8. Ratio of Phase 2 to Phase 1 regional generation amounts.

Figures 9-11 show the levels of generation for each region by technology in terawatt-hours in 2030. Also, each bar shows the level of total demand for the region in 2030, including energy used for pumped storage. A few regions show some differences in generation between the two phases, most notably in coal, wind, and CC technologies.

In the CO_2+ scenario, a few regions are large exporters of electricity (notably MISO W, Nebraska, SPP N, SPP S, and the Canadian regions), while most others import at least some of their energy needs. Several, such as Entergy, PJM, New York, and New England, rely extensively on imports. (Imports from non-EI Canadian provinces are shown as a separate item in the columns.) The BAU and RPS/R scenarios have most of the regions relatively self-sufficient in power.

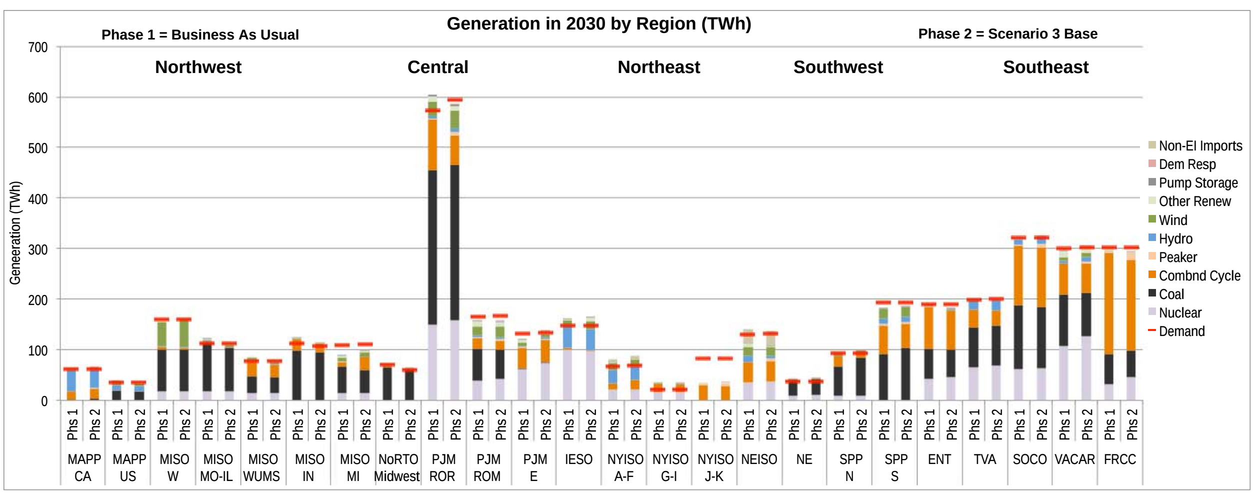


Fig. 9. Generation amounts by region in 2030 in the BAU scenario. (Red rules/marks on the bars indicate the levels of total demand in 2030.)

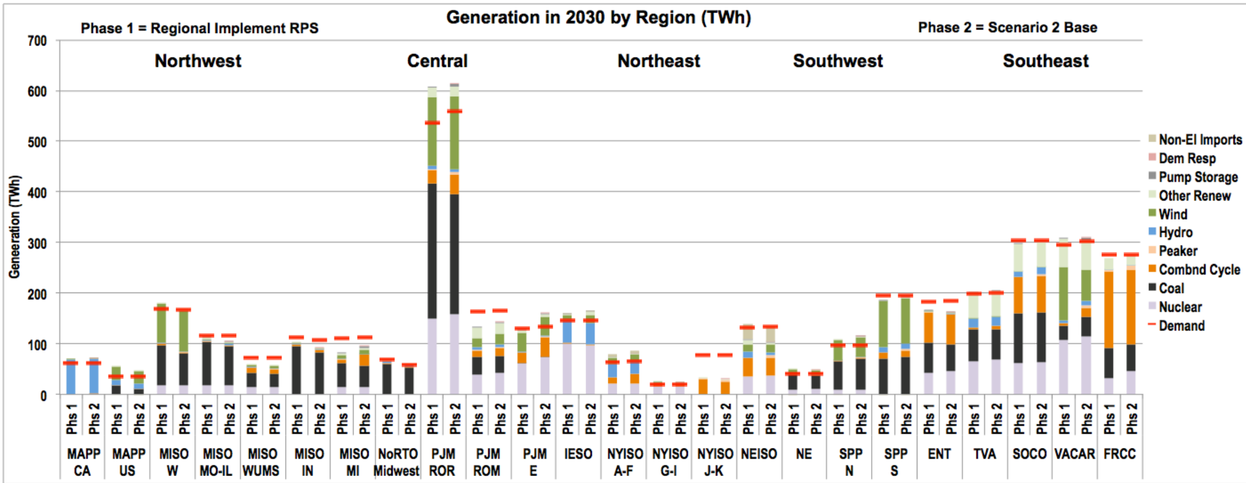


Fig. 10. Generation amounts by region in 2030 in the RPS/R scenario. (Red rules/marks on the bars indicate the levels of total demand in 2030.)

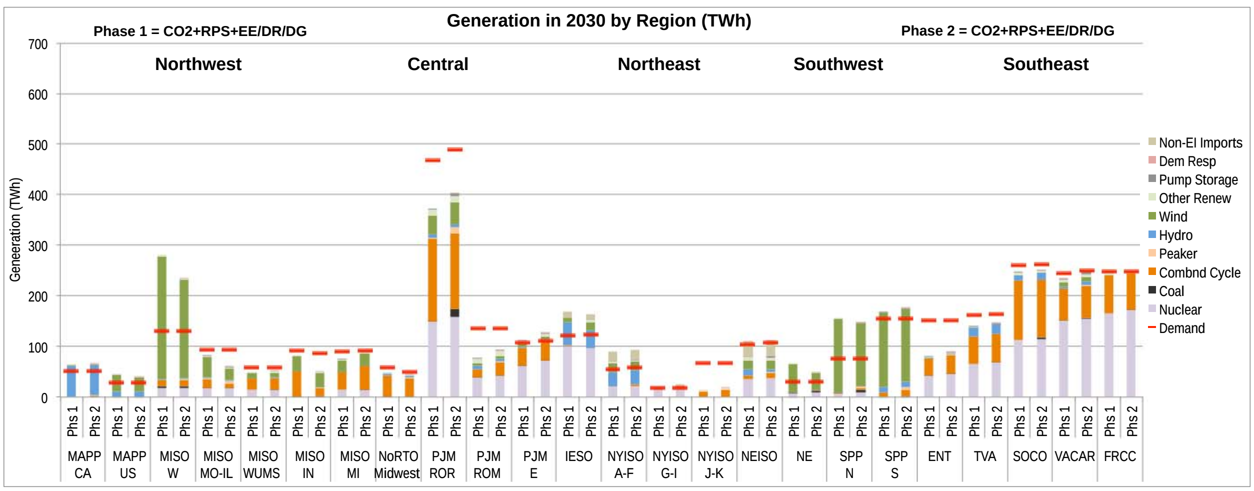


Fig. 11. Generation amounts by region in 2030 in the CO_2+ scenario. (Red rules/marks on the bars indicate the levels of total demand in 2030.)

1.3 Transmission

Phase 1 and Phase 2 show significant differences in transmission between some of the key regions, largely because of refinements in the transmission system design in Phase 2. In Phase 1, transmission (or rather "transfer capacity") was modeled in a complicated process to let the NEEM model expand the capacity in connection with the relative cost difference between regions. First, the reference case was run with no expansion of transmission. Next, a "soft" future was run where the capacity was allowed to fluctuate based on the relative marginal generating costs between regions determined in the reference case. Lastly, the SSC examined the results over the 2025–2040 period and created a set of algorithms that "hardened" that capacity into available transfer capacity that applied in all years. In Phase 2, the EIPC began with the hardened transfer capacity calculated in Phase 1 as a target and set the generation and demand for each region based on the NEEM results from two points during 2030. Transmission lines were then added in the PSS/E build-outs so that generation would supply the demand along with meeting key North American Electric Reliability Corporation (NERC) reliability requirements.

Figures 12–17 are stylized maps of the NEEM regions showing the peak amount of transmission between each region in Phase 1 and Phase 2. The peak amount is shown because tie-line capacity (which is part of what transmission planning attempts to assess) is more directly related to the peak amount of transfer rather than the average amount. Use of a transmission line will vary from hour to hour (or second to second in reality). Power transfer can reverse direction depending on the relative supply and demand for power in the different regions. Furthermore, the tie-lines shown here are rough approximations of actual transmission line flows. Electricity actually follows the “path of least resistance,” and transfers between regions will travel over a number of lines and through multiple neighboring regions. Voltage levels, substation design, and other factors greatly complicate actual electricity flows over the wires.

The BAU scenario had the least level of transfer (Figs. 12 and 13) because without an RPS or CO_2 cost, most regions used more of their internally generated fossil fuel power. There were no high voltage direct current (HVDC) lines added in either phase for this scenario. There was still some transfer due to variations in generation and cost between regions that facilitated exchange. Phase 2 showed relatively the same amounts of transfer as Phase 1; some regions had higher levels and others lower.

The RPS/R scenario had increased peak amounts of transfer, and the peaks are higher for Phase 2 than for Phase 1 (Figs. 14 and 15). In this scenario, much of the transfer was from PJM ROR to surrounding regions, rather than into the region as in the CO_2+ scenario. There were no HVDC lines added for this scenario. This was due to the regional implementation of RPS (resulting in little transmission to other regions) plus the lack of a CO_2 cost, so that much of the coal capacity in the region remained active. The Phase 2 results have higher transfers because the hourly modeling with variations in wind and other generation gives opportunities for transfers that the Phase 1 NEEM model does not see.

For the CO_2+ scenario (Figs. 16 and 17), in Phase 1 the largest transfer is 19.8 GW from MISO W to PJM ROR over the high voltage alternating current lines (blue in the figures) as there were no HVDC lines (red in Fig. 17) included in the model. In Phase 2, PJM ROR also received significant power from the two SPP regions (over HVDC lines) as well as from MISO WUMS and MISO MI. Significant flows go out from PJM ROR in both phases, but in Phase 2 the flow returns back into MISO IN instead of just to the east and south.

More detailed information on transmission amounts on each of the interregional tie-lines, including both peak and average flow amounts in the two phases for different scenarios, is available in Sect. 4.2.5 of the EIPC Phase 2 Report, Part 2 (EIPC 2012). The key result from that analysis was that in the CO_2+ scenario there was a total of 223 GW in peak power transfer in Phase 2 while the Phase 1 case only had 137 GW. The PSS/E analysis performed in Phase 2 increased the requirement for transmission capacity in the CO_2+ scenario beyond what Phase 1 specified to meet reliability constraints, and the GE MAPS model took advantage of the added capacity to the maximum extent possible.

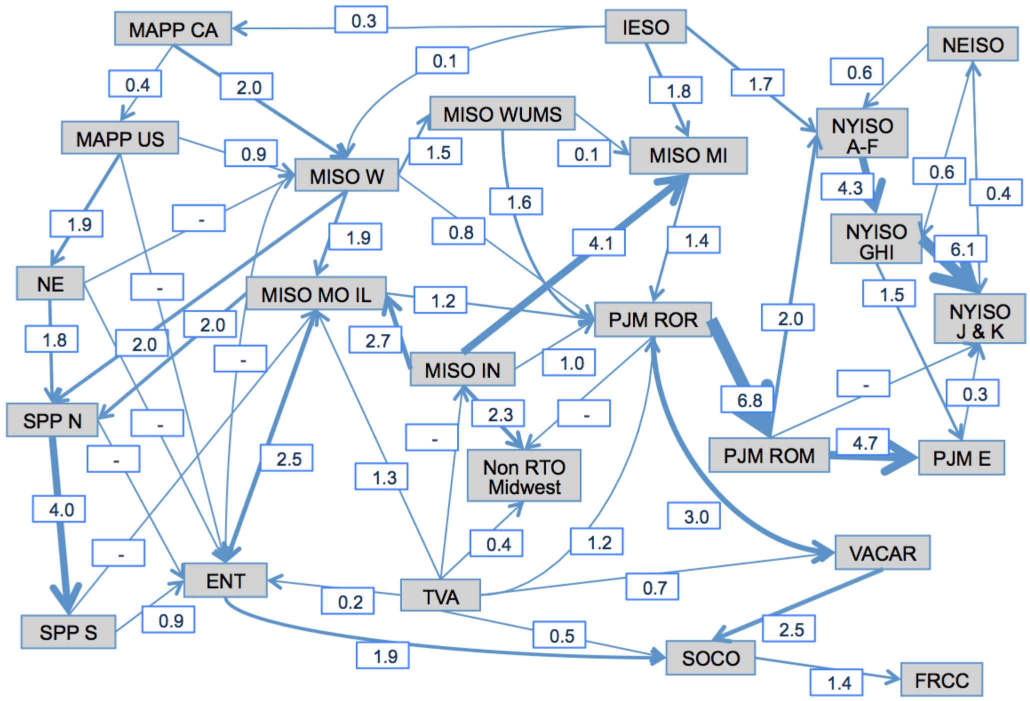


Fig. 12. Phase 1 maximum interregional transfers (GW) in 2030 in the BAU scenario.

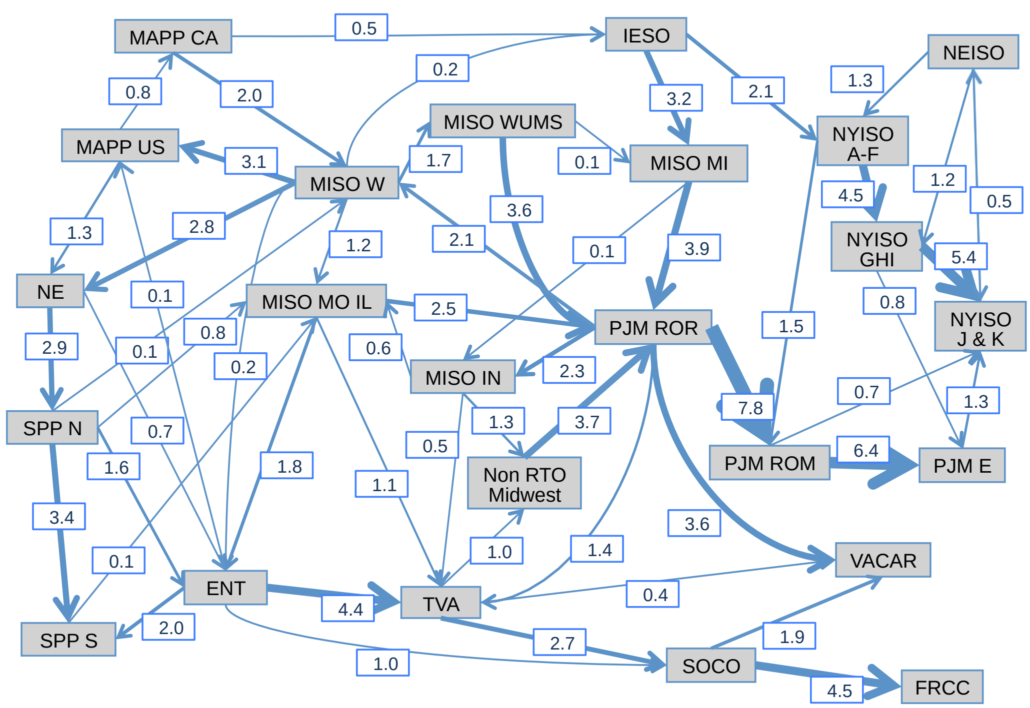


Fig. 13. Phase 2 maximum interregional transfers (GW) in 2030 in the BAU scenario.

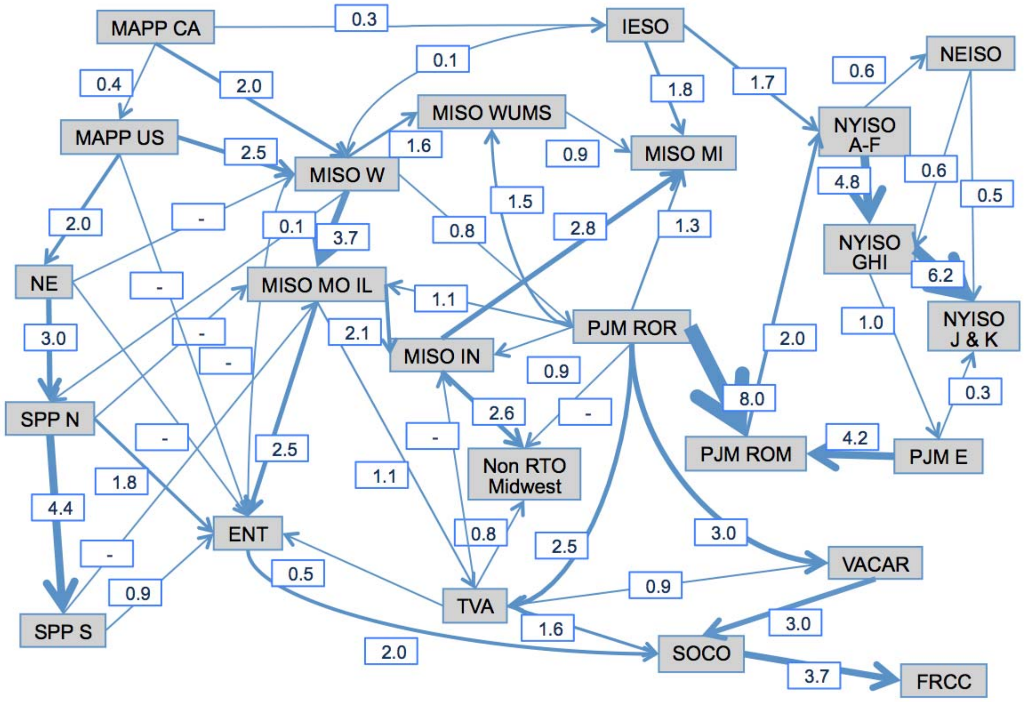


Fig. 14. Phase 1 maximum interregional transfers (GW) in 2030 in the RPS/R scenario.

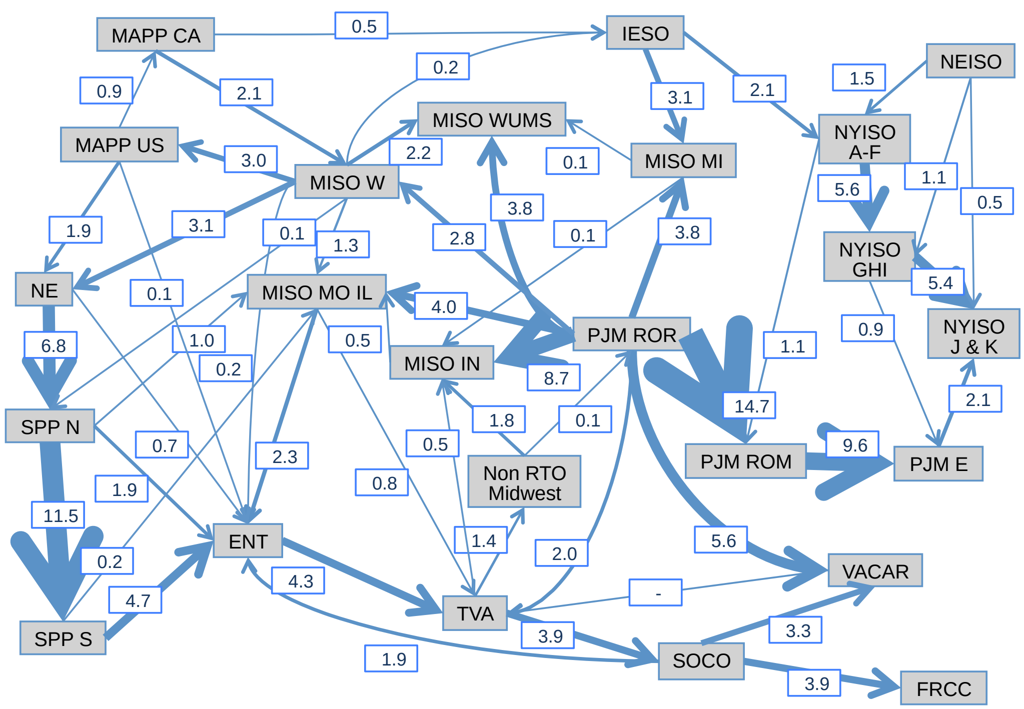


Fig. 15. Phase 2 maximum interregional transfers (GW) in 2030 in the RPS/R scenario.

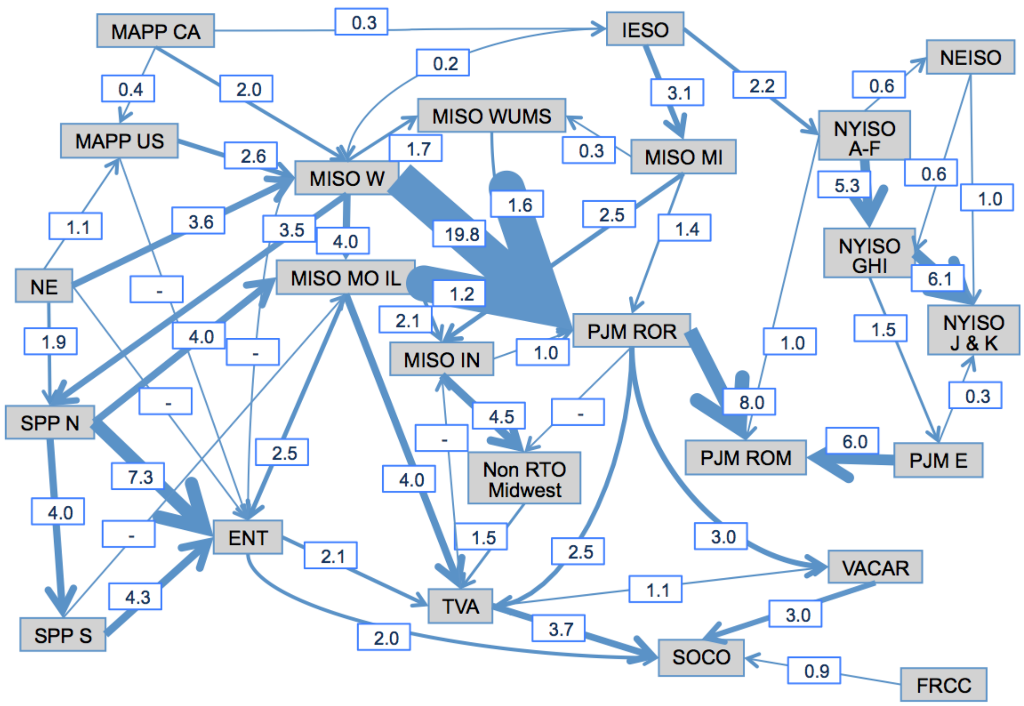


Fig. 16. Phase 1 maximum interregional transfers (GW) in 2030 in the CO_2+ scenario.

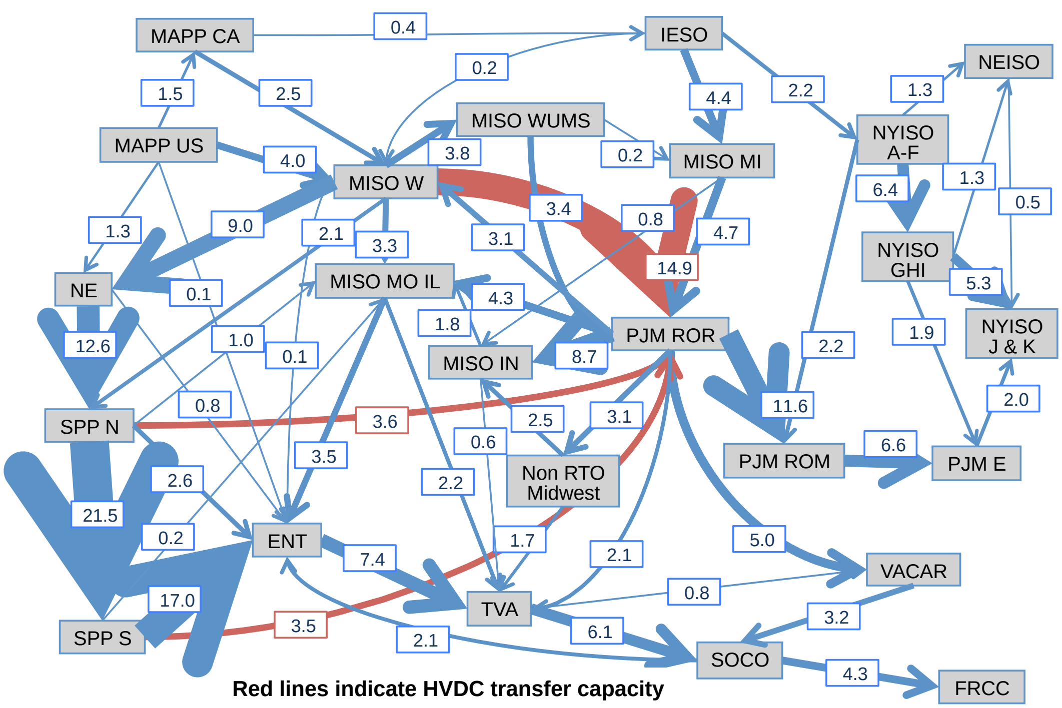


Fig. 17. Phase 2 maximum interregional transfers (GW) in 2030 in the CO_2+ scenario.

Figures 12–17 focus on the peak amount of transfer between regions; however, another important factor is the total amount transferred over a year. Figures 18–23 show the average amount or, more precisely, the total amount transferred in gigawatt-years (1 GWy = 8,760 GWh). Besides the amount transferred, the regions are colored based on the net amount of generation either imported in (red) or exported out (blue) of the region. The scale for the colors varies depending on the highest exports and imports.

The BAU scenario shows relatively little transfer over the full year in the two phases (Figs. 18 and 19). The major transfers are from upstate New York down to NYISO J-K and from PJM ROR to PJM ROM and further east. There is little difference between the two phases.

The RPS/R scenario has similar levels of annual flow to those of the BAU, although transfers are up slightly (Figs. 20 and 21). This is likely due to the increased renewable production in certain regions and transfers needed to move that to other regions. In this scenario, sharing of renewable resources occurred within territories for purposes of meeting the RPS.

For the CO_2+ scenario, in Phase 1 there was a consistent high amount of transfer from MISO W to PJM ROR (Fig. 22). This was a major driving force for adding four HVDC lines between the regions during the transmission build-out in Phase 2 (Fig. 23). In addition, it worked well to have some of the exports from the Southwest go directly to PJM ROR over two HVDC lines rather than transfer through MISO W. An interesting side impact of the HVDC lines in Phase 2 was that a significant amount of power flowed back in to MISO IN from PJM ROR. This may be due to placement of several of the HVDC termini on PJM lines that are within Indiana.

A key difference between Phase 1 and Phase 2 was the number of periods analyzed over the course of a year, twenty blocks in Phase 1 versus 8,760 hours in Phase 2. Table 5 shows the number of hours used in each block in Phase 1.

Table 5. Duration Blocks Used for Each Year Modeled in NEEM

	Summer										Shoulder					Winter				
Block	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20
Hours	10	25	75	100	200	300	400	500	800	1262	25	200	600	900	1203	25	100	400	700	935

Modeling each hour separately in Phase 2 provided much more opportunity for transmission to increase, decrease, or even change direction depending on the generation and demands in different regions. We can aggregate the hourly results from Phase 2 into the corresponding blocks from Phase 1 to see how the transmission varied over the year. There are 56 tie-lines between the regions. To pick one as an example, Fig. 24 shows the power transferred between SPP N and SPP S during the CO_2+ scenario. This line saw much heavier use in Phase 2 than Phase 1. In Phase 1, each block could have a different transfer amount, so there were a maximum of 20 different transfer amounts over the course of a year in NEEM. These blocks contain between 10 and 1,262 hours and total to the 8,760 hours of the year. We aggregated the corresponding hours from the MAPS results and derived the average, maximum, and minimum for each block. The last set of points in the figure shows the annual aggregated values.

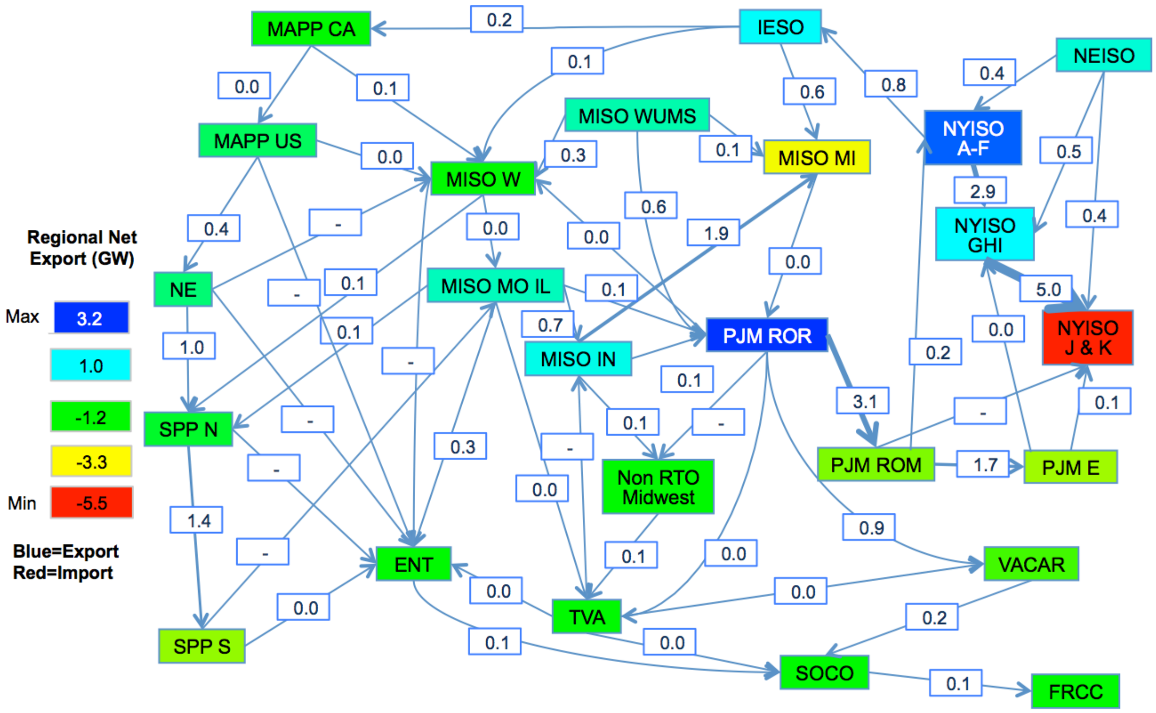


Fig. 18. Phase 1 average interregional transfers (GW) in 2030 in the BAU scenario.

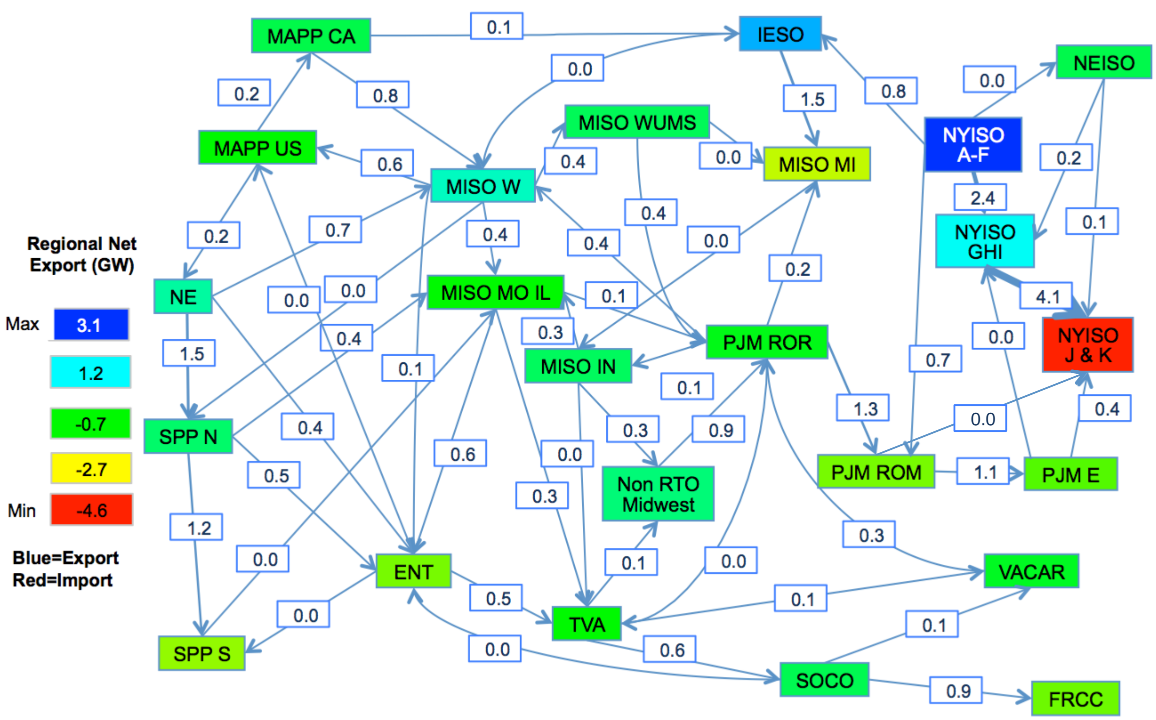


Fig. 19. Phase 2 average interregional transfers (GW) in 2030 in the BAU scenario.

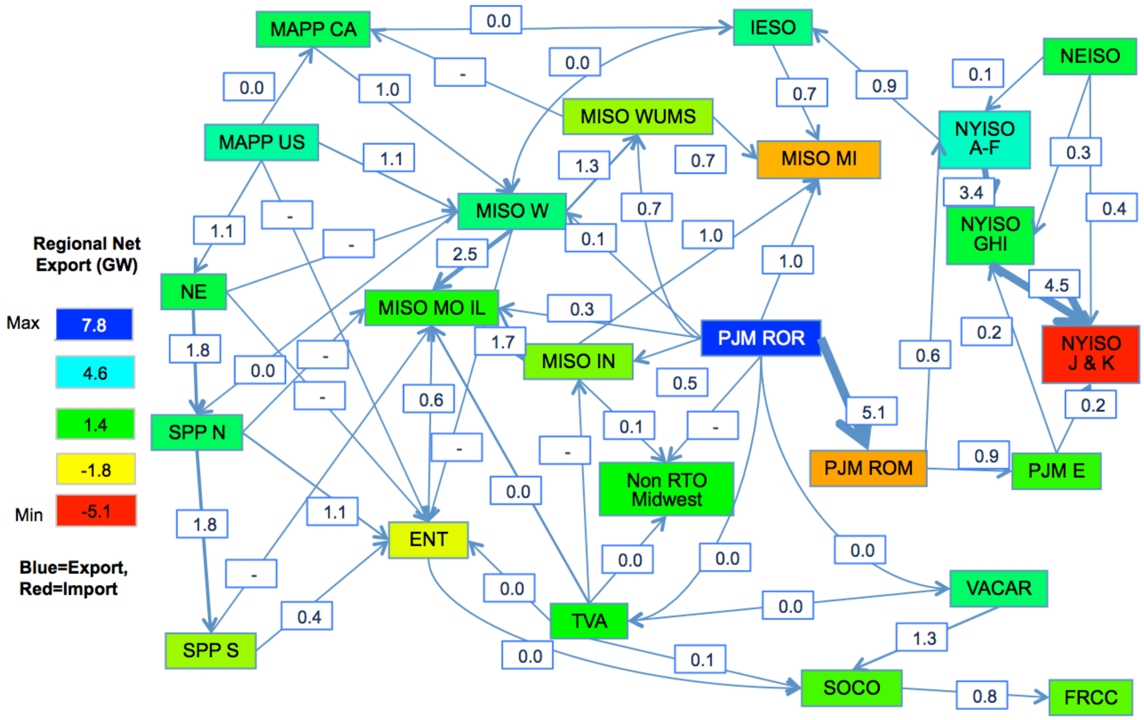


Fig. 20. Phase 1 average interregional transfers (GW) in 2030 in the RPS/R scenario.

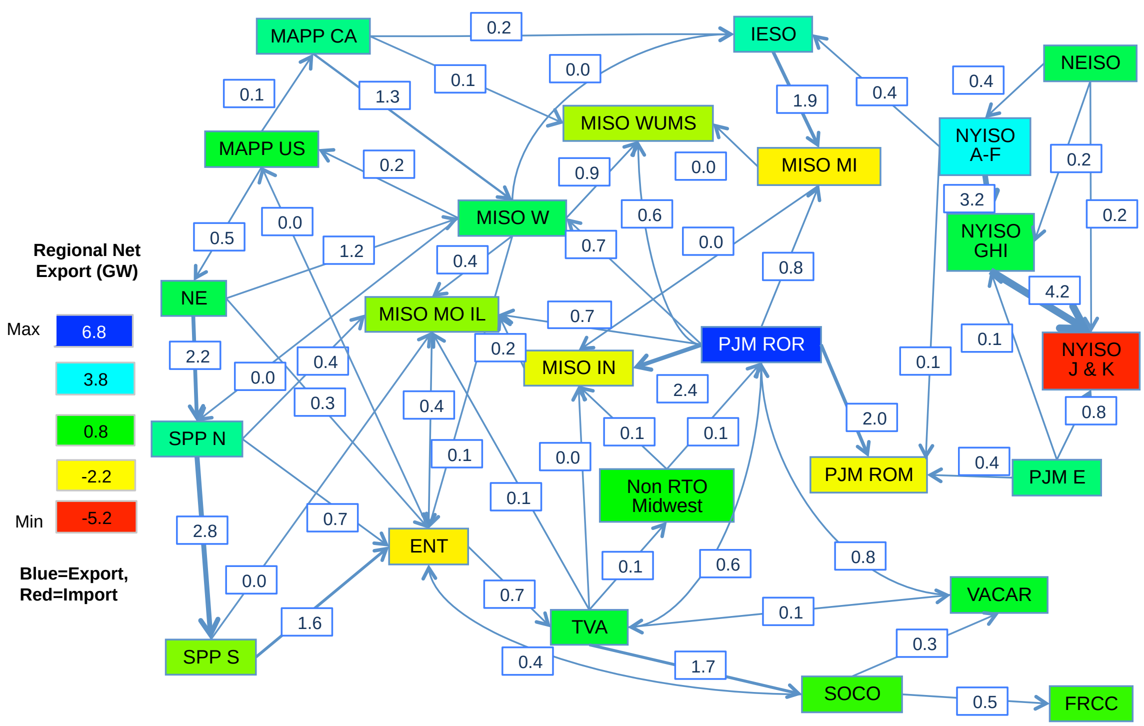


Fig. 21. Phase 2 average interregional transfers (GW) in 2030 in the RPS/R scenario.

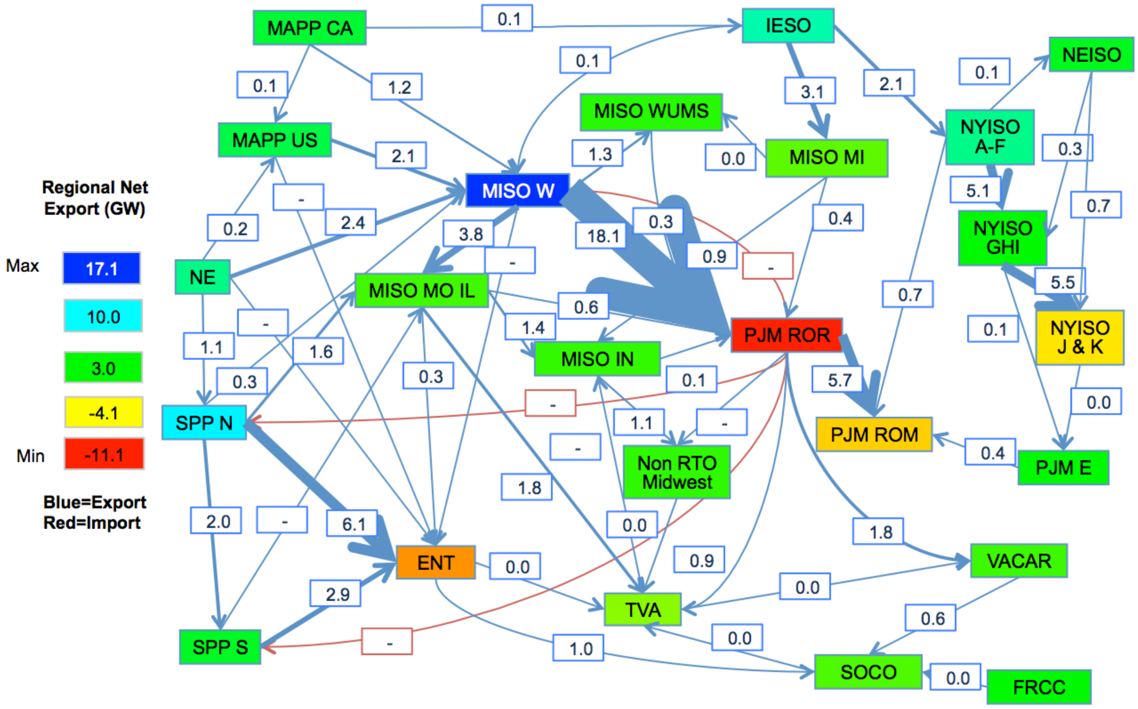


Fig. 22. Phase 1 average interregional transfers (GW) in 2030 in the CO_2+ scenario.

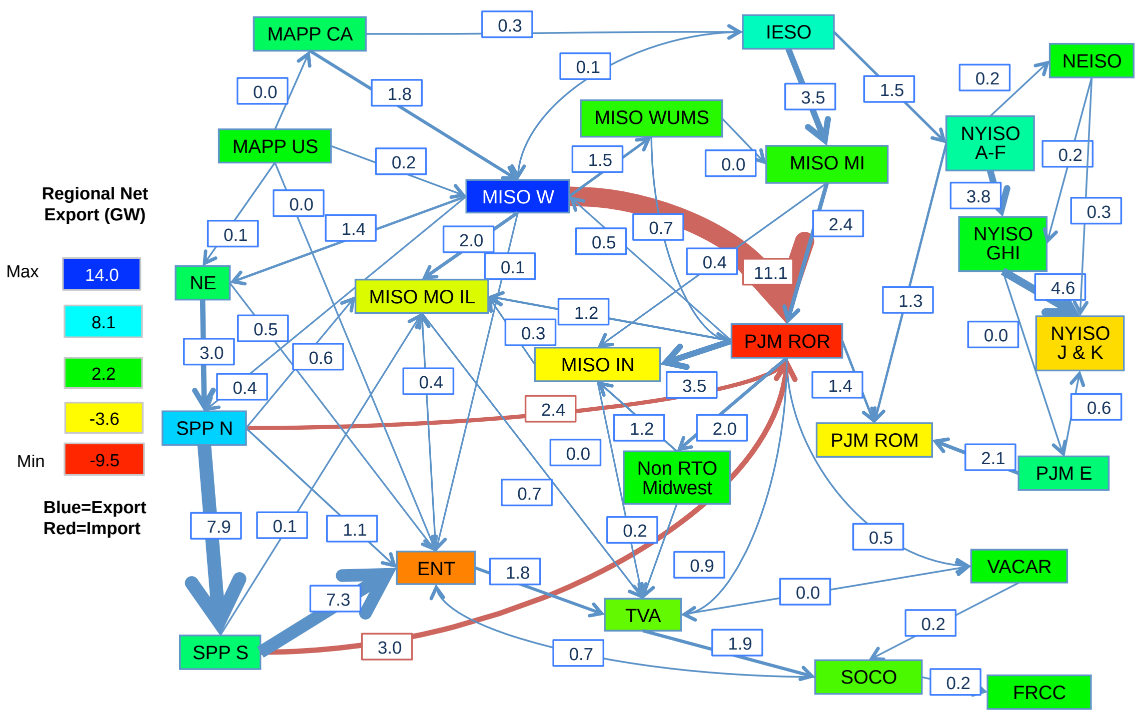


Fig. 23. Phase 2 average interregional transfers (GW) in 2030 in the CO_2+ scenario.

In Fig. 24, Block 1, the 10 summer peak hours, Phase 1 results had 640 MW of power transferring from SPP S to SPP N; Phase 2 results had between 5 and 14 GW transferred from SPP N to SPP S, with an average of 10 GW. Recall that Phase 2 included the SPP high voltage overlay that provided extensive transfer capacity between the two regions. Other blocks showed even broader diversity in the amount transferred between the regions. (Blocks 11 and 16 are the peak hours for the other seasons and so have less diversity.) During Block 18 (400 hours in the winter), in Phase 2 the transfers ranged from 3 GW traveling south to north to 21 GW traveling north to south. This variation could be due to wind pattern differences, plant outages, different internal or export demands, or the modeling of minor cost differences during times of surplus generation. This will be explored in more detail in the next set of topics.

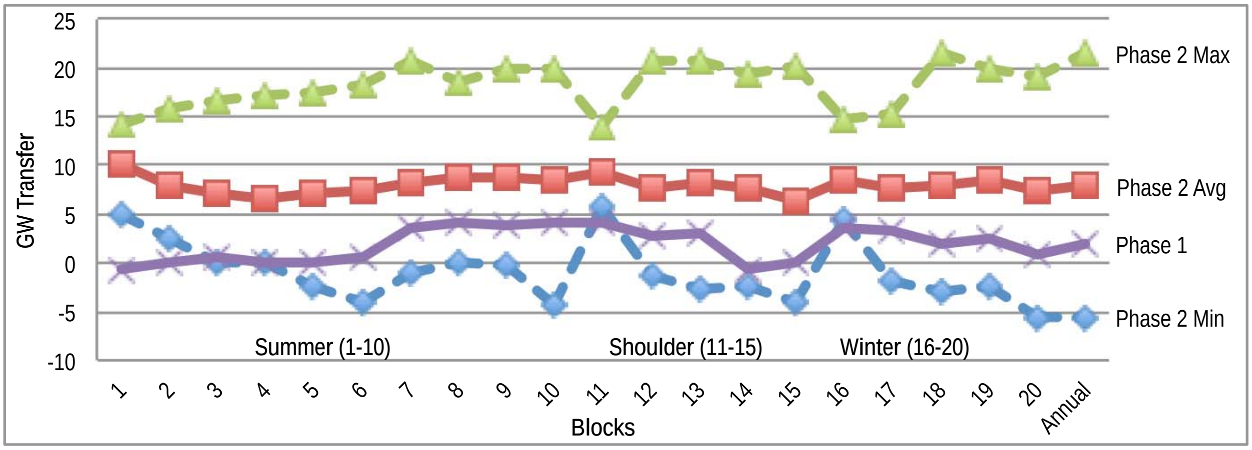


Fig. 24. SPP N to SPP S transmission in the CO_2+ scenario aggregated to NEEM load blocks.

1.4 Cost Comparison

Total costs include generation costs as calculated within the models plus other costs calculated separately. These costs include the transmission capital costs, nuclear uprates, DR, EE, DG, and others. These are discussed in more detail in Topic 3. Some cost categories were calculated differently in Phase 1 than in Phase 2. For example, in Phase 1 the capital costs for generation were levelized into costs applied each year, using capital recovery factors between 11% and 12% depending on the technology. Transmission capital costs were only calculated as a single total construction cost for the whole period and only applied to transmission over and above the Stakeholder-Specified Infrastructure (SSI). In Phase 2, both generation and transmission capital costs were calculated as the total period's construction cost. To levelize the generation and transmission construction costs, we applied an average capital recovery factor of 11.5% to all capital.

1.4.1 Ratio of Total Cost in 2030 Between Scenarios

As the focus of this chapter is a comparison of Phase 2 results to Phase 1 results, the ratio of total 2030 cost indicates how they compared (Fig. 25). Costs for most of the regions were higher in Phase 2 (ratio >100%), especially in the CO_2+ scenario with total costs 16% higher. Capital costs appear to be a main driver in this; Phase 2 capital costs were 24% higher for the entire EI. Only five regions had capital costs lower in Phase 2 than Phase 1.

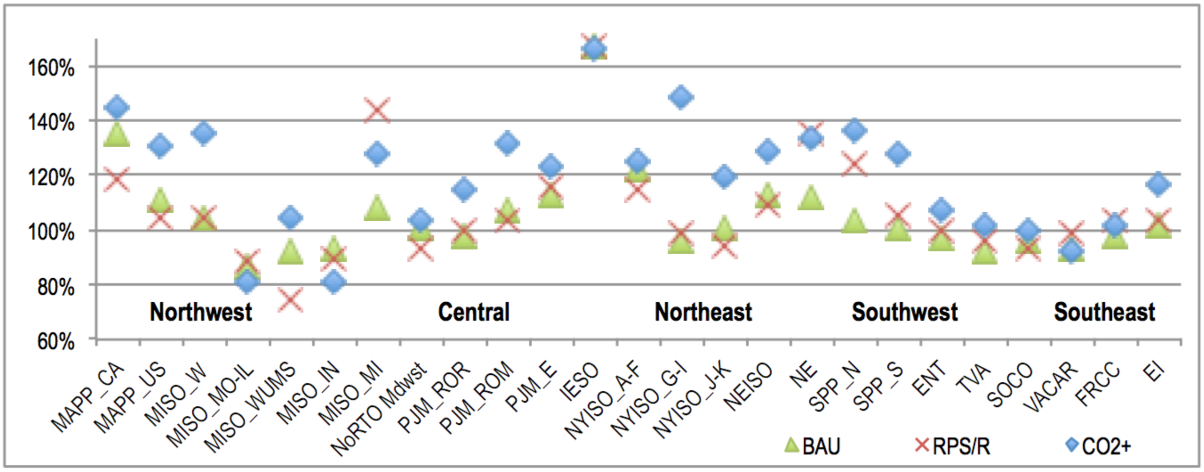


Fig. 25. Ratio of Phase 2 to Phase 1 generation costs in 2030 by region.

1.4.2 Total by Type and Region

Total costs for most regions are relatively similar between Phase 1 and 2 (Figs. 26-28). The largest differences are in those regions that have high wind generation (MISO W, SPP N, SPP S) in the CO_2+ scenario. Capital costs make up the biggest difference in MISO W, but in SPP the cost difference also includes more fuel and emissions cost due to the added coal, CC, and CT generation during wind shortfalls or for reserves. Scenarios 2 and 3 do not have as great a difference between phases.

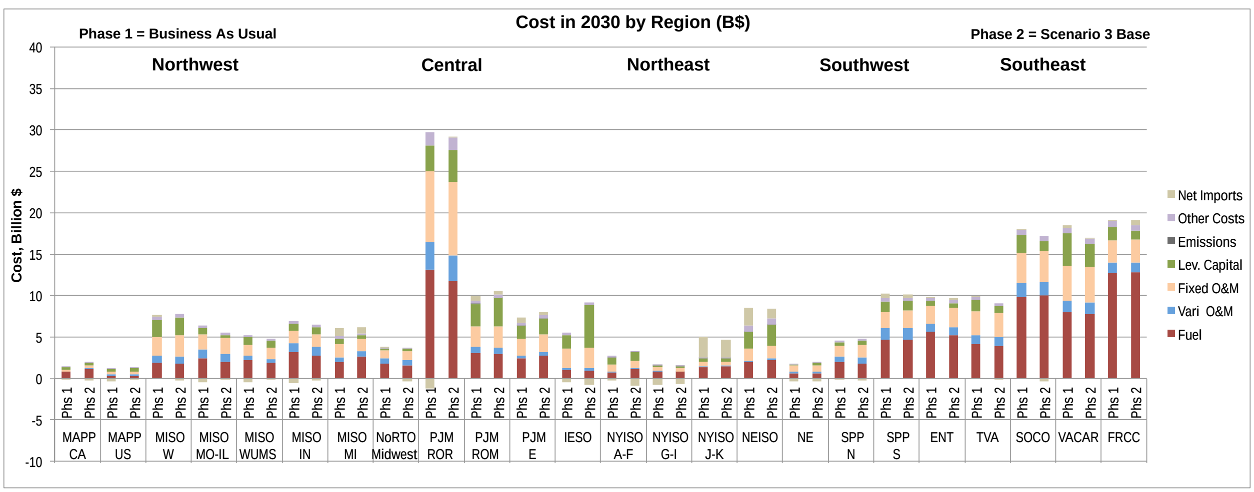


Fig. 26. Phase 1 and Phase 2 regional total costs in 2030 in the BAU scenario.

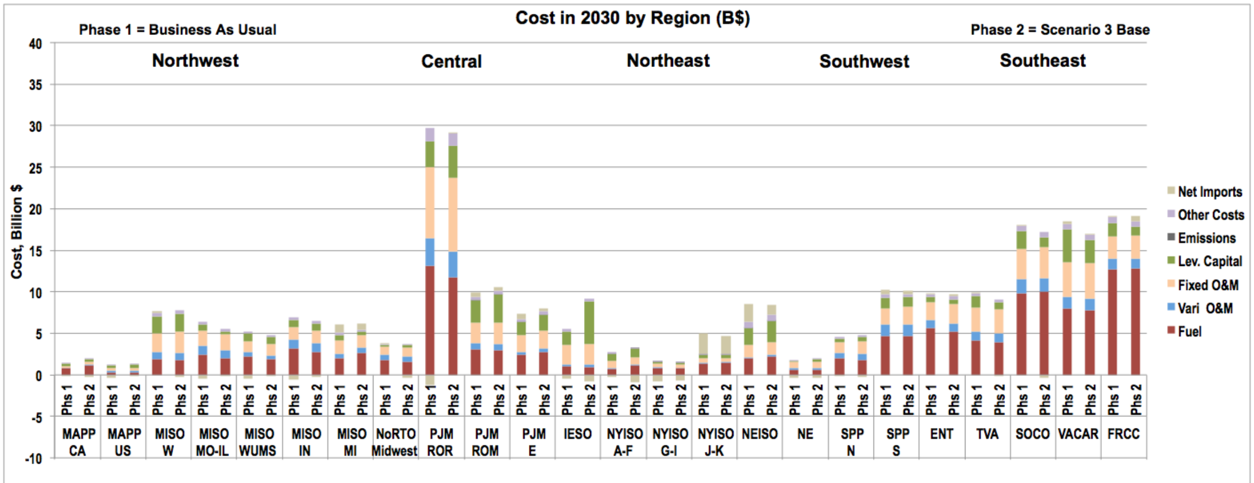


Fig. 27. Phase 1 and Phase 2 regional total costs in 2030 in the RPS/R scenario.

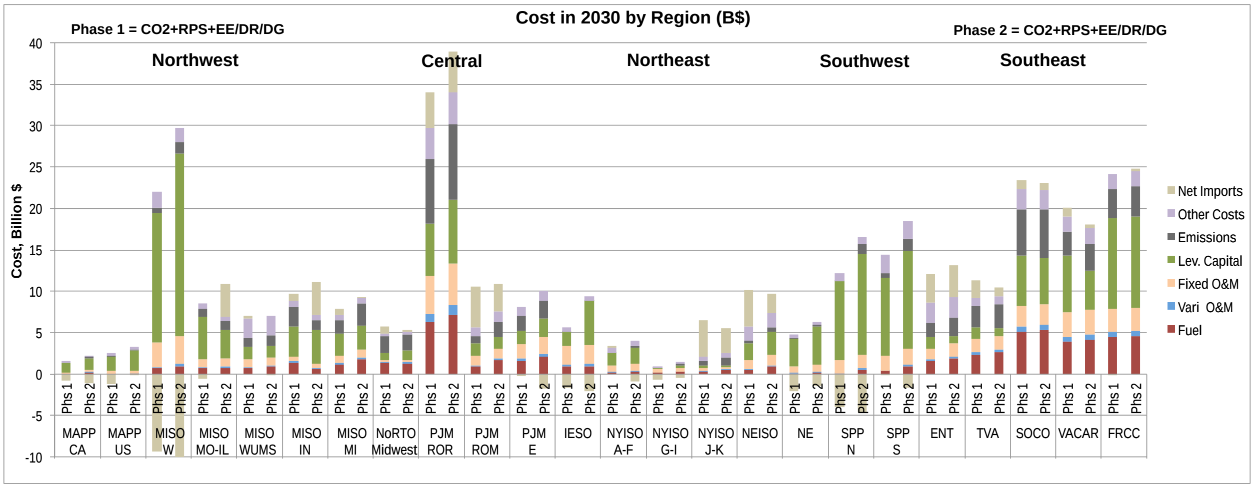


Fig. 28. Phase 1 and Phase 2 regional total costs in 2030 in the CO_2+ scenario.

1.4.3 Cost per Unit of Generation

Cost per unit of generation puts cost on a more comparable basis between regions (Figs. 29-31). Cost per unit of generation results amplify the differences in the CO_2+ scenario for those regions with high wind production, MAPP US, MISO W, NE, SPP N, and SPP S. These costs do not include the net import costs and the divisor does not include imports or exports, so this is a measure of the average cost per unit of generation, not cost per unit of demand in the region.

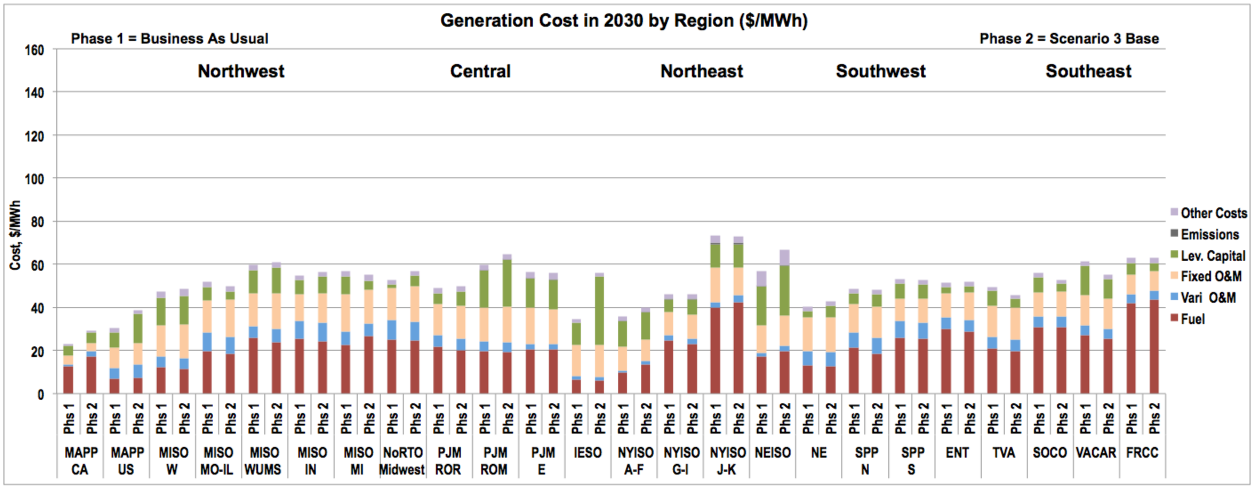


Fig. 29. Phase 1 and Phase 2 regional total cost per megawatt-hour generated in the BAU scenario.

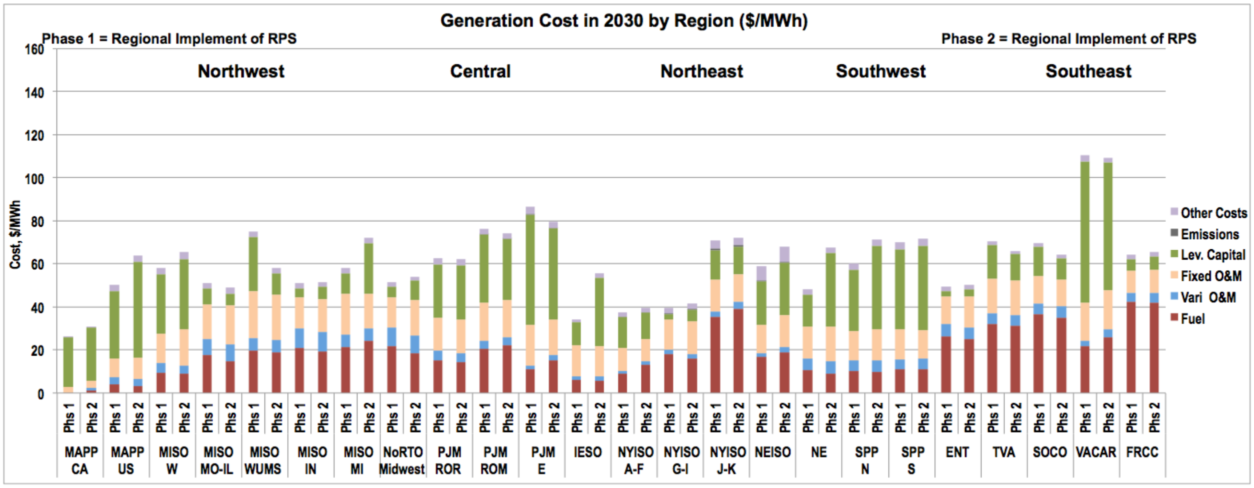


Fig. 30. Phase 1 and Phase 2 regional total cost per megawatt-hour generated in the RPS/R scenario.

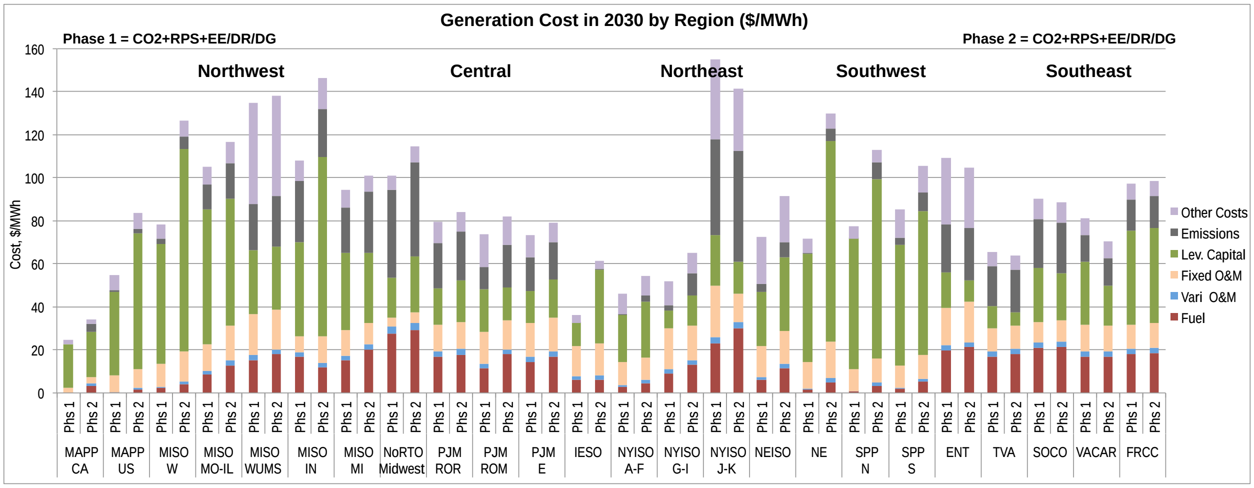


Fig. 31. Phase 1 and Phase 2 regional total cost per megawatt-hour generated in the CO_2+ scenario.

2. TOPIC 2: REGIONAL RESULTS OVER TIME

This chapter evaluates the change in capacity, generation, and interregional transfers over time. The reason for this topic is many regulators or other stakeholders were concerned that there could be issues that they might face in the nearer term than 2030. The most pressing issues might be changes in generation or transmission capacity, since these require the most upfront response.

Earlier years than 2030 were only analyzed in Phase 1 of the study. Most results were only reported in 5-year increments beginning in 2015. The timing of transmission changes is difficult to evaluate because the amount of transfer capacity between regions was modeled as a constant over the full time period.

The figures below show the changes in capacity and generation over time, based on the Phase 1 results. Rather than show all 24 regions, the section below shows the changes for each of the major territories as defined in Table 1. In addition, tables showing the points of major change in capacity, generation, and net exports are highlighted. Only those technologies that have more than a 5% share of the generation and have a change greater than 25% are shown. Export changes greater than +/-10% between years are highlighted. Changes past 2030 are not included in the tables as those years are more speculative and of less interest than results up to 2030.

In all regions and scenarios, excess generation is deactivated between 2010 and 2015 by MRN-NEEM. Most often this capacity is coal and steam oil/gas. DR grows in capacity significantly through 2025.

The following sections show the graphs of capacity from 2010–2040 next to the graphs of generation from 2015–2040 for each scenario for a given territory, with that of the EI as a whole first. Following the figures in each section are tables telling when significant changes occurred to capacity, generation, and net transfers for the territory between 2010 and 2015 (capacity changes only), 2015 and 2020, 2030 and 2025, and 2005 and 2030. Following the tables is a brief description of key changes.

2.1 Eastern Interconnection as a Whole

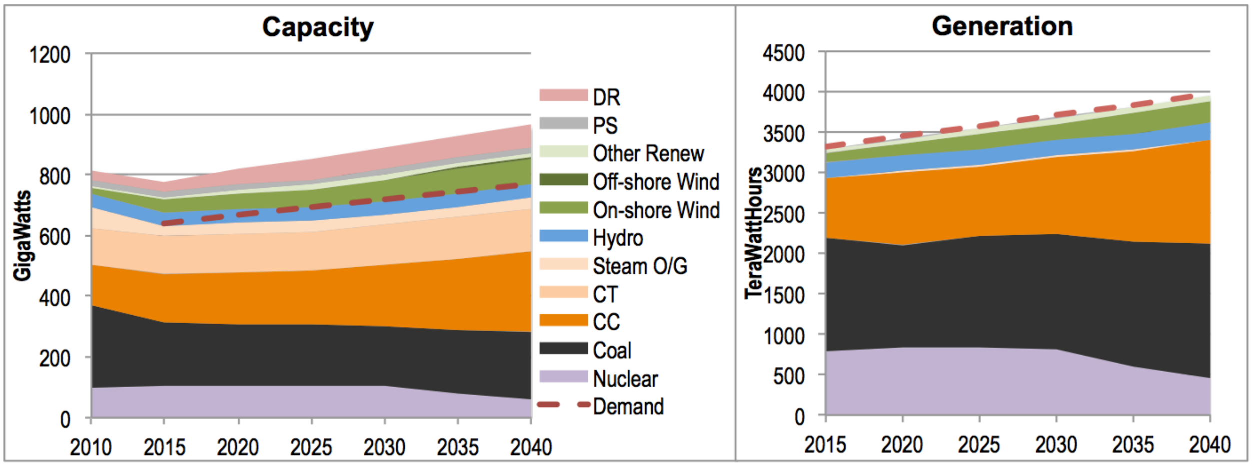


Fig. 32. BAU scenario Phase 1 capacity and generation for the Eastern Interconnection as a whole.

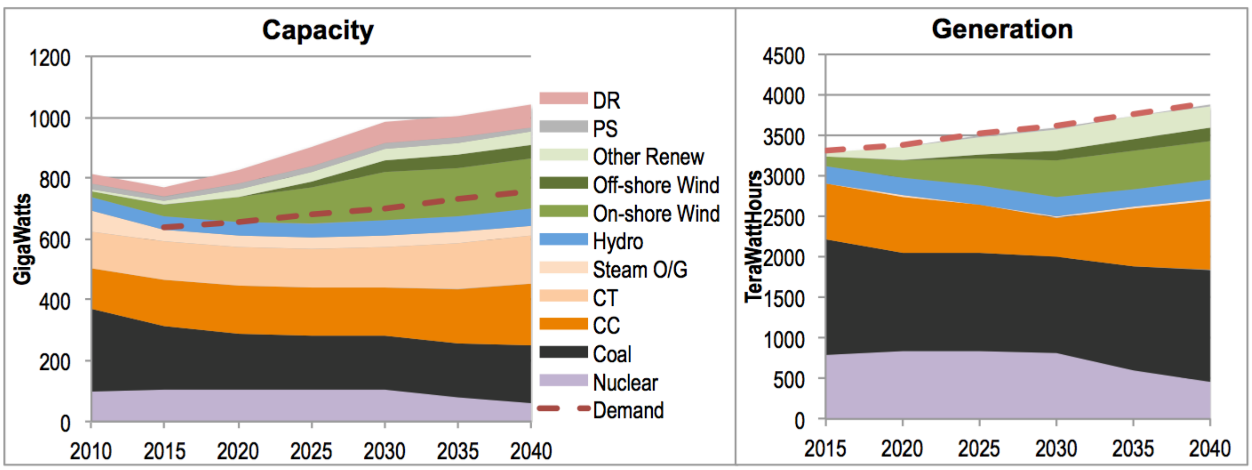


Fig. 33. RPS/R scenario Phase 1 capacity and generation for the Eastern Interconnection as a whole.

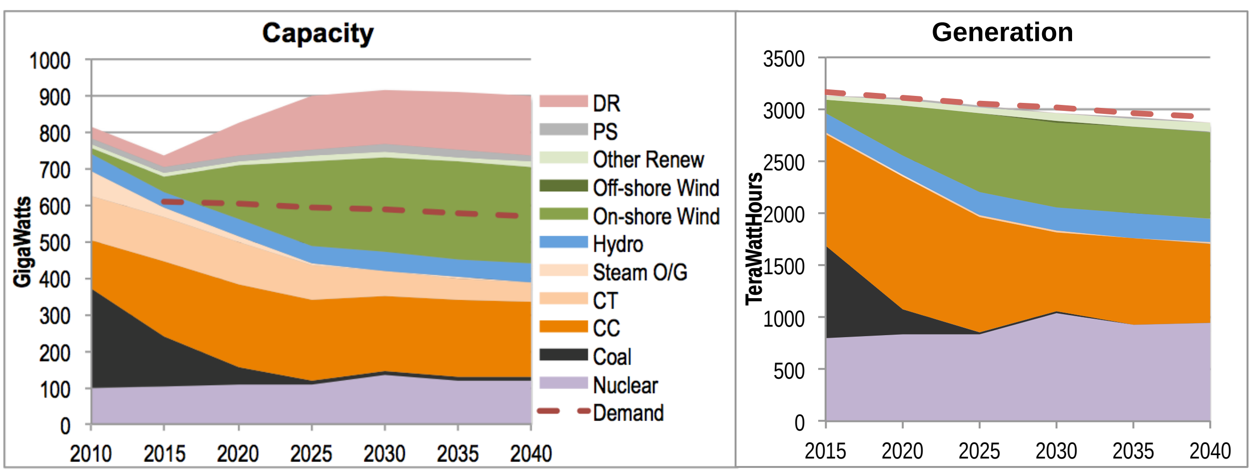


Fig. 34. CO_2+ scenario Phase 1 capacity and generation for the Eastern Interconnection.

Table 6. BAU Scenario Significant Changes Through 2030 in the Eastern Interconnection as a Whole

NEEM Region: EI		Scenario: F1S17	
2015	2020	2025	2030
Significant Capacity Changes			
• Steam O/G down 52% to 34.6 GW • Onshore wind up 119% to 40.9 GW	• Onshore wind up 30% to 53.1 GW • DR up 53% to 48.6 GW	• Demand response (DR) up 40% to 68.2 GW	
Significant Generation Changes			
Significant Net Export Changes (negative = Imports)			

Table 7. RPS/R Scenario Significant Changes Through 2030 in the Eastern Interconnection as a Whole

NEEM Region: EI		Scenario: F6S10	
2015	2020	2025	2030
Significant Capacity Changes			
• Steam O/G down 50% to 35.9 GW • Onshore wind up 119% to 40.9 GW	• Onshore wind up 99% to 81.3 GW • Demand response (DR) up 53% to 48.6 GW	• Onshore wind up 45% to 118.2 GW • DR up 40% to 68.2 GW	• Onshore wind up 35% to 159.3 GW
Significant Generation Changes			
	• Onshore wind up 95% to 227.5 TWh	• Onshore wind up 46% to 332.6 TWh • Other renewables up 32% to 210.5 TWh	• Onshore wind up 38% to 457.6 TWh
Significant Net Export Changes (negative = Imports)			

Table 8. CO_2+ Scenario Significant Changes Through 2030 in the Eastern Interconnection as a Whole

NEEM Region: EI		Scenario: F8S7	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 49% to 138.8 GW • Combined cycle (CC) up 56% to 207.2 GW • Steam O/G down 67% to 23.9 GW • On-shore Wind up 119% to 40.9 GW	• Coal down 66% to 47.2 GW • Onshore wind up 259% to 146.7 GW • Demand response (DR) up 172% to 86.5 GW	• Coal down 78% to 10.2 GW • Onshore wind up 58% to 231.5 GW • DR up 70% to 146.9 GW	• Combustion turbine down 31% to 66.0 GW
Significant Generation Changes			
	• Coal down 72% to 250.6 TWh • Onshore wind up 309% to 474.9 TWh	• Coal down 93% to 18.1 TWh • Onshore wind up 57% to 746.6 TWh	• CC down 31% to 769.5 TWh
Significant Net Export Changes (negative = Imports)			

Changes to the EI as a whole have been described in the full EIPC report. The BAU scenario has most growth occurring steadily, with coal and CC the major contributors (Fig. 32). In the RPS/R scenario, onshore wind grows more gradually over time; offshore wind and other renewables become more significant contributors in place of CC (Fig. 33). The CO_2+ scenario shows a rapid decline in coal capacity and generation and a large increase in both wind and DR capacity. Nuclear capacity grows somewhat and provides a growing fraction of generation (Fig. 34).

2.2 Northwest

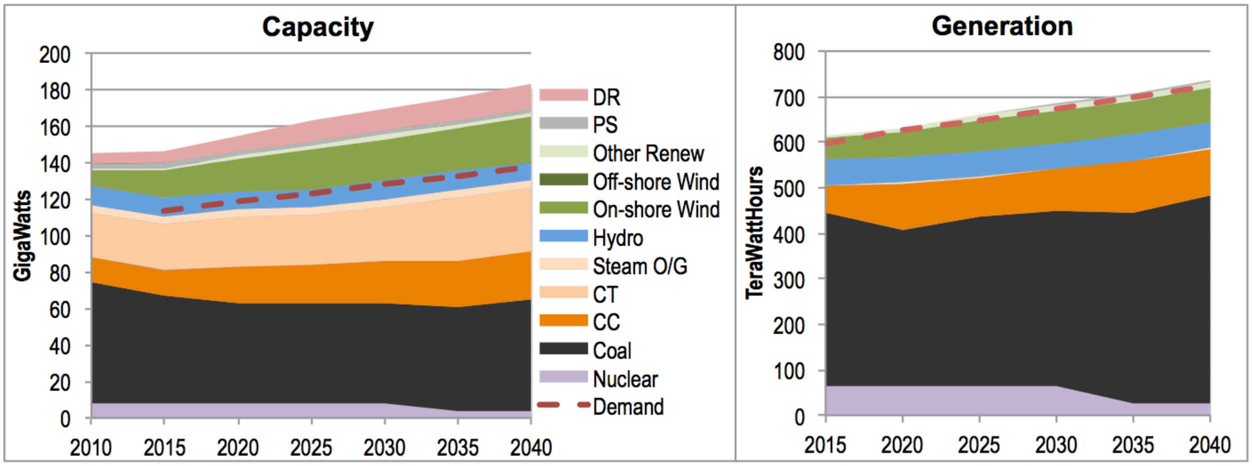


Fig. 35. BAU scenario Phase 1 capacity and generation for the Northwest Eastern Interconnection.

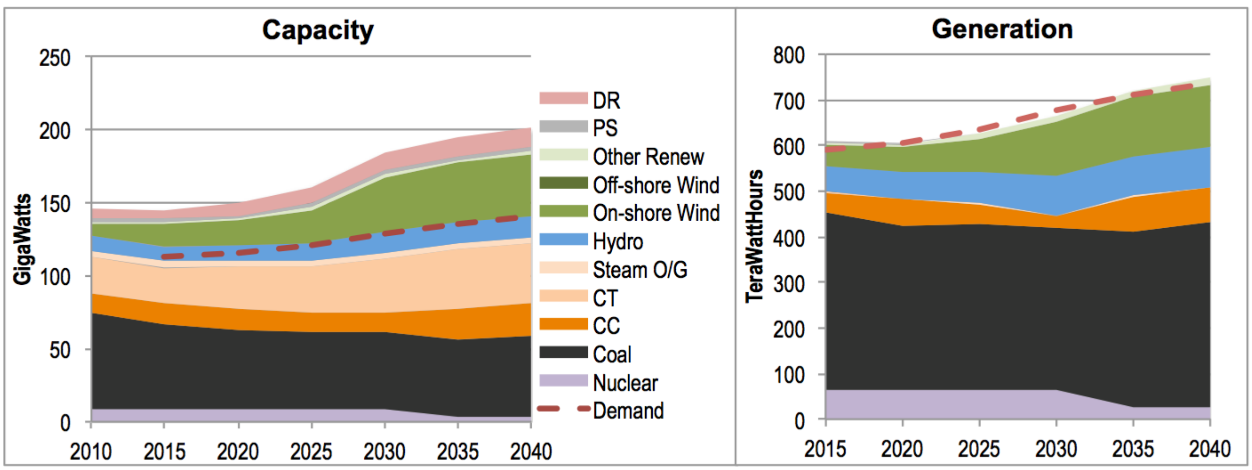


Fig. 36. RPS/R scenario Phase 1 capacity and generation for the Northwest Eastern Interconnection.

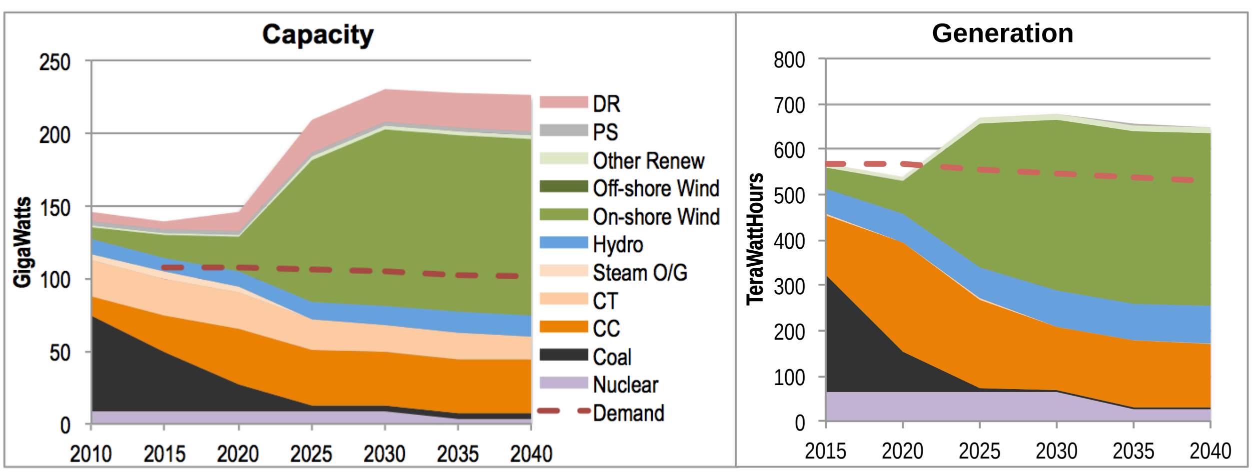


Fig. 37. CO_2+ scenario Phase 1 capacity and generation for the Northwest Eastern Interconnection.

Table 9. BAU Scenario Significant Changes Through 2030 in the Northwest Eastern Interconnection

Territory: Northwest		Scenario: F1S17	
2015	2020	2025	2030
Significant Capacity Changes			
• Onshore wind up 78% to 15.5 GW	• Combined cycle (CC) up 36% to 19.6 GW • DR up 40% to 8.6 GW	• Demand response (DR) up 34% to 11.6 GW	
Significant Generation Changes			
	• CC up 68% to 101.1 TWh		
Significant Net Export Changes (negative = Imports)			

Table 10. RPS/R Scenario Significant Changes Through 2030 in the Northwest Eastern Interconnection

Territory: Northwest		Scenario: F6S10	
2015	2020	2025	2030
Significant Capacity Changes			
• Onshore wind up 78% to 15.5 GW	• Demand response (DR) up 40% to 8.6 GW	• Onshore wind up 30% to 22.2 GW • DR up 34% to 11.6 GW	• Onshore wind up 67% to 36.9 GW
Significant Generation Changes			
	• Combined cycle (CC) up 34% to 58.7 TWh	• CC down 27% to 43.0 TWh • Onshore wind up 32% to 69.8 TWh	• CC down 41% to 25.4 TWh • Onshore wind up 71% to 119.4 TWh
Significant Net Export Changes (negative = Imports)			

Table 11. CO_2+ Scenario Significant Changes Through 2030 in the Northwest Eastern Interconnection

Territory: Northwest		Scenario: F8S7	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 37% to 41.9 GW • Combined cycle (CC) up 84% to 25.0 GW • Onshore Wind up 78% to 15.5 GW	• Coal down 56% to 18.3 GW • CC up 56% to 39.0 GW • Onshore wind up 50% to 23.4 GW • DR up 123% to 13.7 GW	• Coal down 79% to 3.8 GW • Onshore wind up 319% to 97.8 GW • Demand response (DR) up 61% to 22.2 GW	
Significant Generation Changes			
	• Coal down 65% to 89.7 TWh • CC up 83% to 239.4 TWh • Onshore wind up 56% to 74.9 TWh	• Coal down 93% to 6.4 TWh • Onshore wind up 323% to 316.7 TWh	• CC down 29% to 139.8 TWh
Significant Net Export Changes (negative = Imports)			
		• Net exports up 25% to 20% of demand	

The Northwest Territory (MISO and MAPP) has a major expansion in wind capacity between 2020 and 2025 in the CO_2+ scenario (Fig. 37), while the RPS/R scenario's biggest increase is delayed to between 2025 and 2030 (Fig. 36). Coal continues as the dominant resource in the BAU (Fig. 35) and RPS/R scenarios, while wind dominates and CC generation expands in the CO_2+ scenario.

2.3 Central

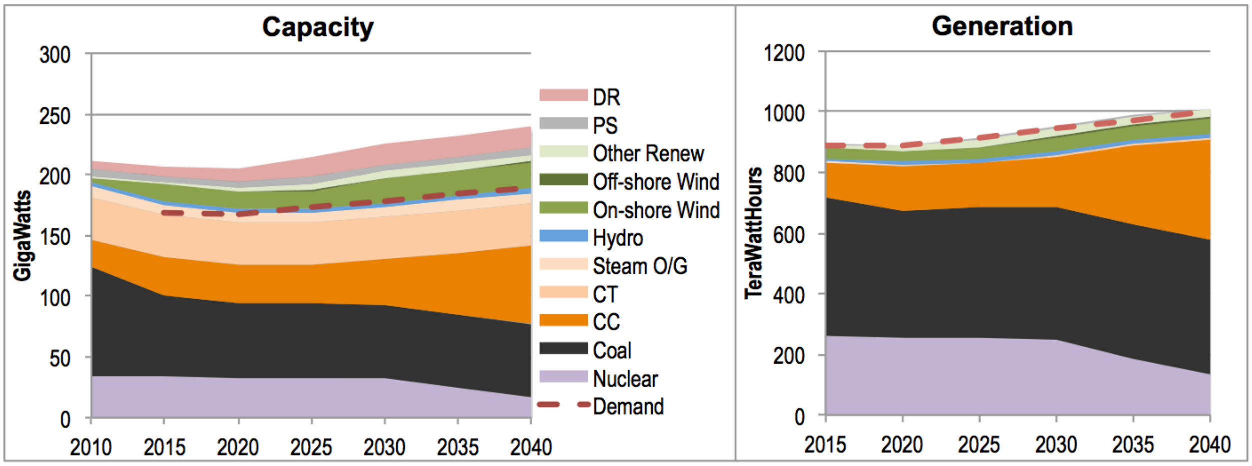


Fig. 38. BAU scenario Phase 1 capacity and generation for the Central Eastern Interconnection.

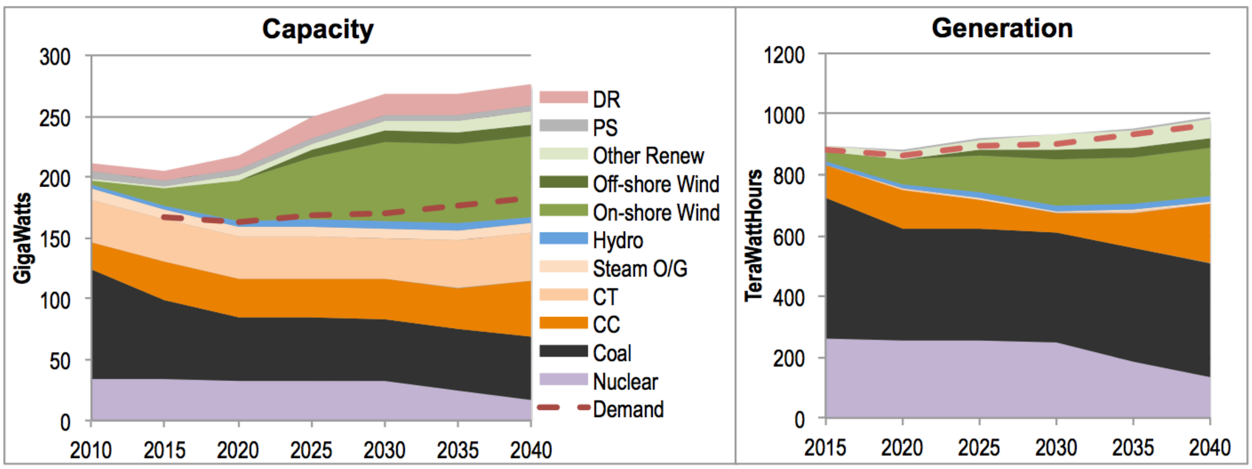


Fig. 39. RPS/R scenario Phase 1 capacity and generation for the Central Eastern Interconnection.

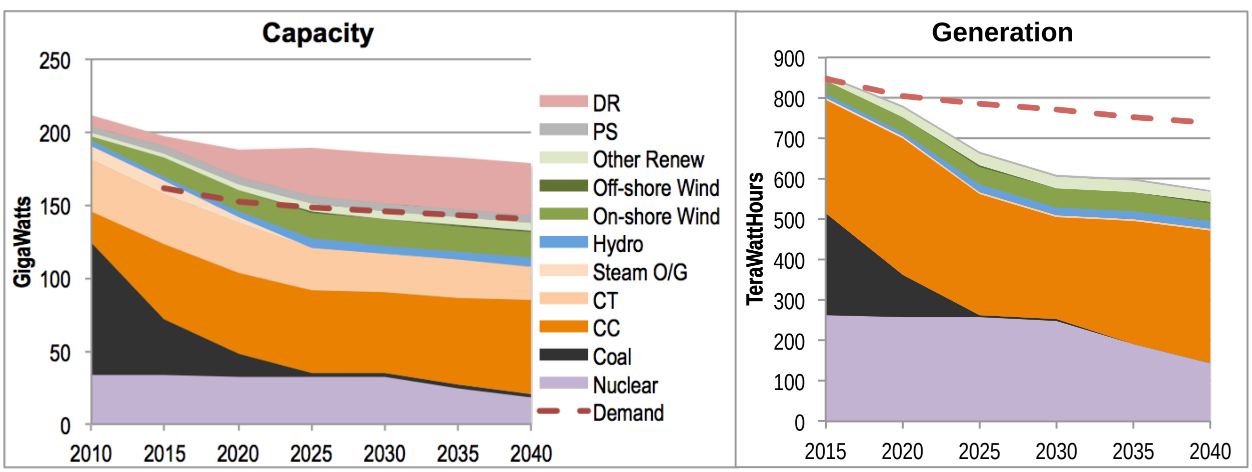


Fig. 40. CO_2+ scenario Phase 1 capacity and generation for the Central Eastern Interconnection.

Table 12. BAU Scenario Significant Changes Through 2030 in the Central Eastern Interconnection

Territory:	Central	Scenario:	F1S17
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 26% to 67.2 GW • Combined Cycle (CC) up 42% to 31.6 GW • Onshore wind up 292% to 13.4 GW	• Demand response (DR) up 59% to 11.2 GW	• DR up 45% to 16.3 GW	• Onshore wind up 41% to 20.1 GW
Significant Generation Changes			
	• CC up 29% to 145.9 TWh		• Onshore wind up 34% to 48.2 TWh
Significant Net Export Changes (negative = Imports)			

Table 13. RPS/R Scenario Significant Changes Through 2030 in the Central Eastern Interconnection

Territory:	Central	Scenario:	F6S10
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 28% to 65.6 GW • Combined cycle (CC) up 42% to 31.6 GW • Onshore wind up 292% to 13.4 GW	• Onshore wind up 149% to 33.2 GW • Demand response (DR) up 59% to 11.2 GW	• Onshore wind up 55% to 51.4 GW • DR up 45% to 16.3 GW	• Onshore wind up 27% to 65.2 GW
Significant Generation Changes			
	• Onshore wind up 136% to 79.1 TWh	• CC down 26% to 92.9 TWh • Onshore wind up 54% to 121.9 TWh	• CC down 32% to 62.9 TWh • Onshore wind up 27% to 154.5 TWh • Other renewables up 63% to 47.0 TWh
Significant Net Export Changes (negative = Imports)			

Table 14. CO_2+ Scenario Significant Changes Through 2030 in Central the Eastern Interconnection

Territory:	Central	Scenario:	F8S7
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 57% to 38.7 GW • Combined cycle (CC) up 132% to 51.5 GW • Onshore wind up 292% to 13.4 GW	• Coal down 60% to 15.3 GW • Demand response (DR) up 174% to 19.4 GW	• Coal down 84% to 2.5 GW • DR up 71% to 33.2 GW	
Significant Generation Changes			
	• Coal down 58% to 106.6 TWh	• Coal down 94% to 6.2 TWh	
Significant Net Export Changes (negative = Imports)			
		• Net exports down 13% to −15% of demand	

In the BAU scenario, coal maintains its dominant market share of production (Fig. 38). In the RPS/R scenario, wind capacity including offshore wind is expanded, and other renewables are developed as well to meet the RPS requirements (Fig. 39). Capacity declines in the CO_2+ scenario, and the Central territory

(PJM and Non-RTO Midwest) becomes a significant importer (Fig. 40). Nuclear continues to play a significant role through 2030, and CC generation is expanded as coal is reduced.

2.4 Northeast

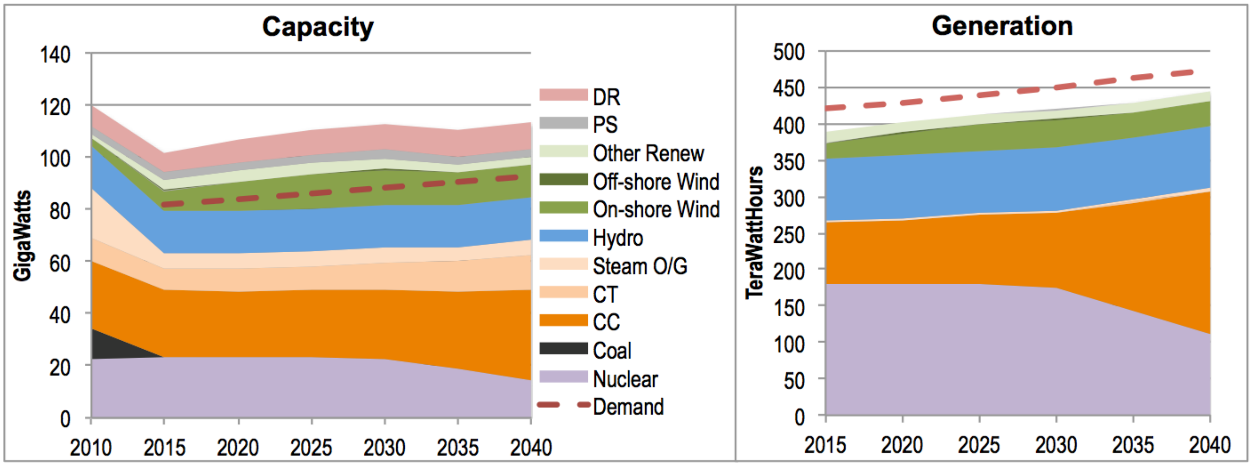


Fig. 41. BAU scenario Phase 1 capacity and generation for the Northeast Eastern Interconnection.

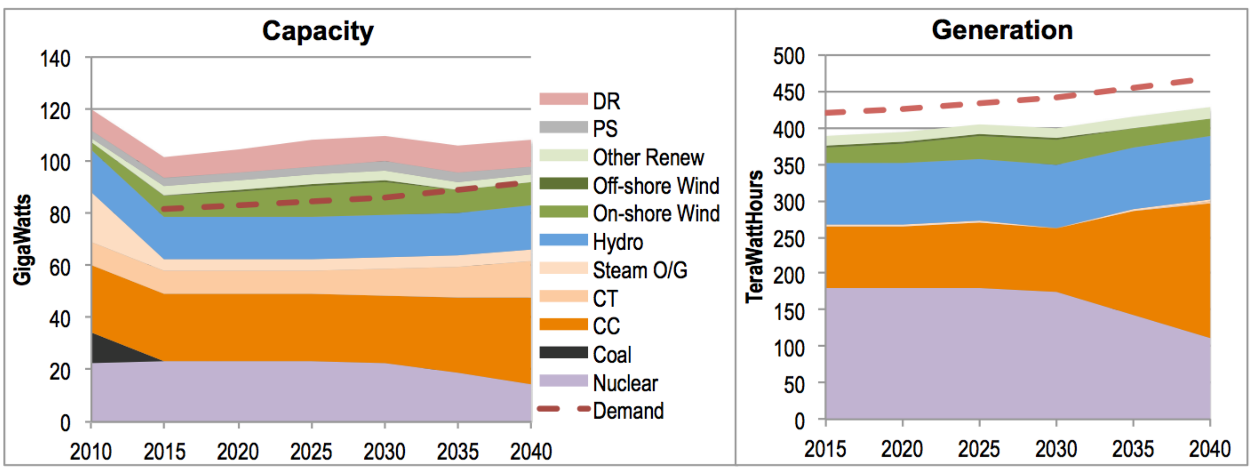


Fig. 42. RPS/R scenario Phase 1 capacity and generation for the Northeast Eastern Interconnection.

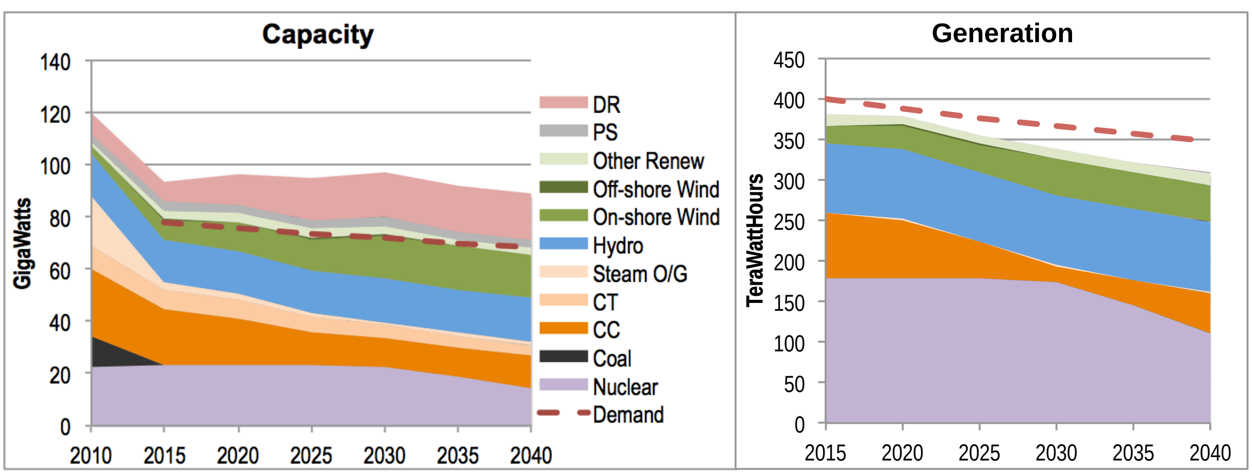


Fig. 43. CO_2+ scenario Phase 1 capacity and generation for the Northeast Eastern Interconnection.

Table 15. BAU Scenario Significant Changes Through 2030 in the Northeast Eastern Interconnection

Territory: Northeast		Scenario: F1S17	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 97% to 0.3 GW • Steam O/G down 71% to 5.7 GW • Onshore wind up 174% to 7.6 GW	• Onshore wind up 46% to 11.1 GW		
Significant Generation Changes			
	• Onshore wind up 51% to 30.0 TWh		
Significant Net Export Changes (negative = Imports)			

Table 16. RPS/R Scenario Significant Changes through 2030 in Northeast Eastern Interconnection

Territory: Northeast		Scenario: F6S10	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 97% to 0.3 GW • Steam O/G down 77% to 4.4 GW • Onshore wind up 174% to 7.6 GW	• Onshore wind up 27% to 9.6 GW		
Significant Generation Changes			
	• Onshore wind up 29% to 25.7 TWh		
Significant Net Export Changes (negative = Imports)			

Table 17. CO_2+ Scenario Significant Changes through 2030 in Northeast Eastern Interconnection

Territory: Northeast		Scenario: F8S7	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 97% to 0.3 GW • Steam O/G down 85% to 2.9 GW • Onshore Wind up 174% to 7.6 GW	• Onshore wind up 43% to 10.9 GW • Demand response (DR) up 55% to 11.8 GW	• Combined cycle (CC) down 31% to 12.6 GW • DR up 40% to 16.5 GW	• Onshore wind up 40% to 16.6 GW
Significant Generation Changes			
	• Onshore wind up 48% to 28.9 TWh	• CC down 38% to 43.8 TWh	• CC down 57% to 18.8 TWh • Onshore Wind up 40% to 44.6 TWh
Significant Net Export Changes (negative = Imports)			

The Northeast territory (New York, New England, and Ontario) imports power from Hydro Quebec and the Maritimes in all three scenarios, with the CO_2+ scenario having the highest imports (Figs. 41-43). A large proportion of power produced is from nuclear and hydro including much from Ontario that supplies both internal demand and the other regions.

2.5 Southwest

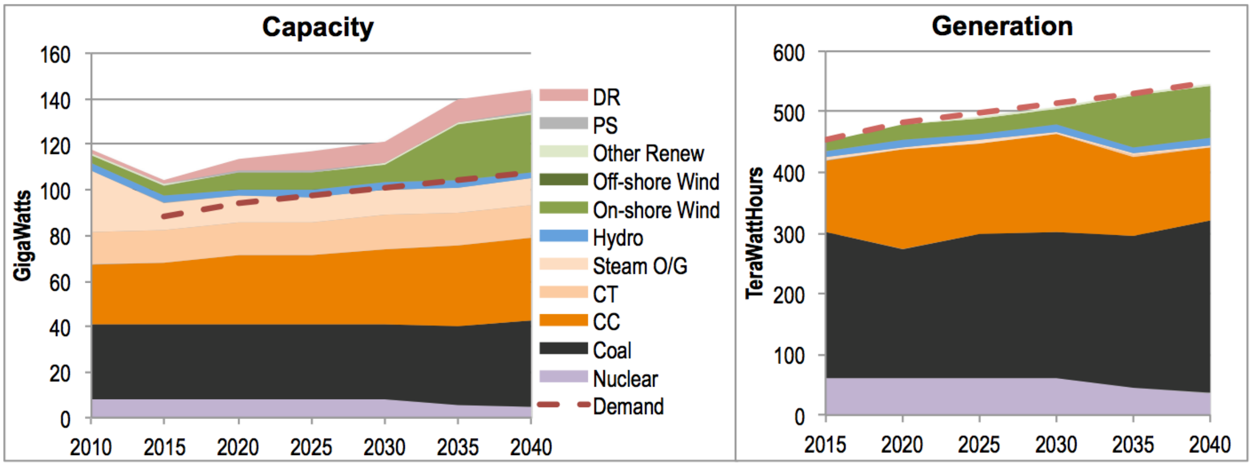


Fig. 44. BAU scenario Phase 1 capacity and generation for the Southwest Eastern Interconnection.

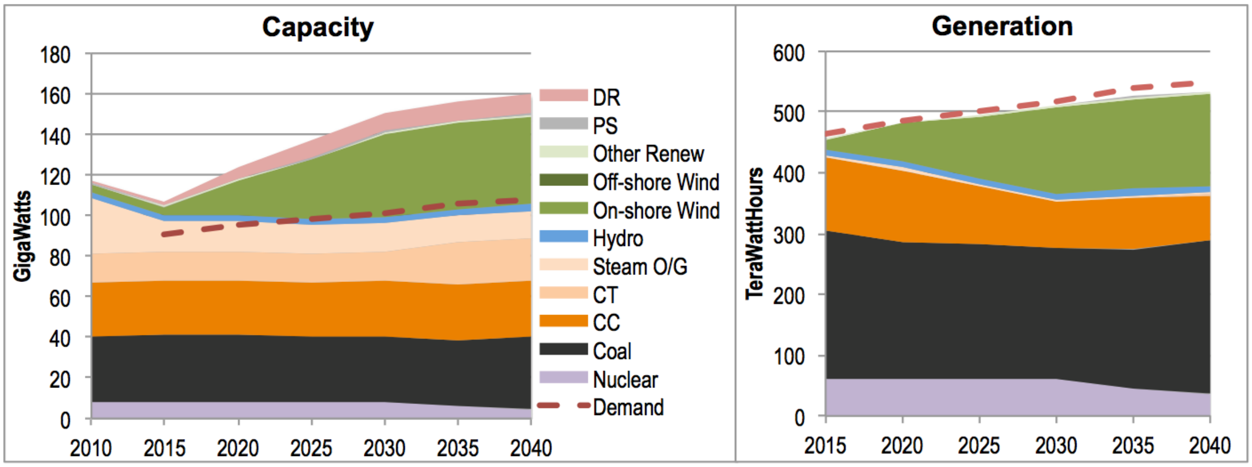


Fig. 45. RPS/R scenario Phase 1 capacity and generation for the Southwest Eastern Interconnection.

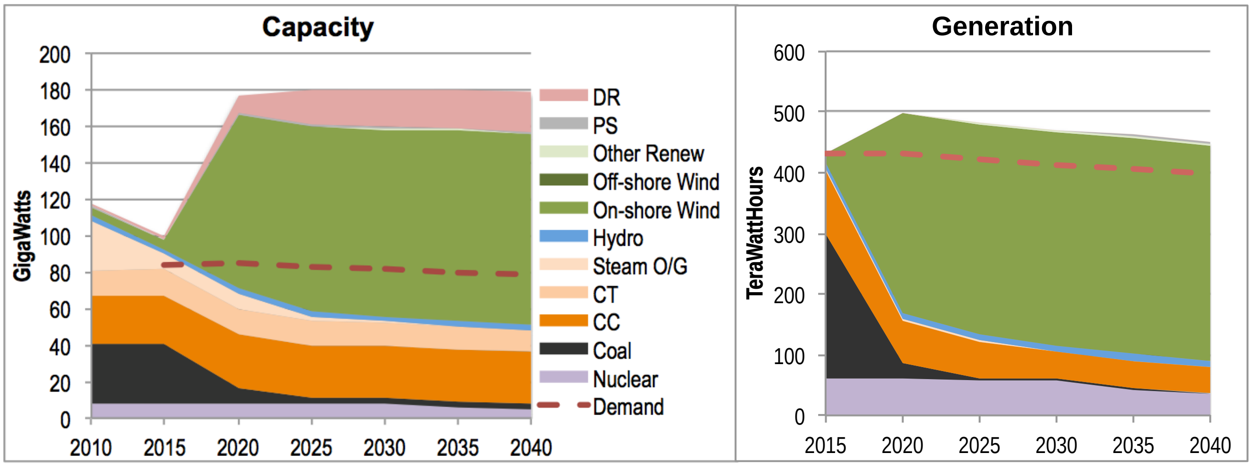


Fig. 46. CO_2+ scenario Phase 1 capacity and generation for the Southwest Eastern Interconnection.

Table 18. BAU Scenario Significant Changes Through 2030 in the Southwest Eastern Interconnection

Territory:	Southwest	Scenario:	F1S17
2015	2020	2025	2030
Significant Capacity Changes			
• Steam O/G down 57% to 11.9 GW	• Onshore wind up 60% to 7.0 GW	• Demand response up 76% to 8.8 GW	
Significant Generation Changes			
	• Combined cycle up 37% to 164.2 TWh • Onshore wind up 60% to 24.3 TWh		
Significant Net Export Changes (negative = Imports)			

Table 19. RPS/R Scenario Significant Changes Through 2030 in the Southwest Eastern Interconnection

Territory:	Southwest	Scenario:	F6S10
2015	2020	2025	2030
Significant Capacity Changes			
• Steam O/G down 46% to 14.8 GW	• Onshore wind up 303% to 17.8 GW	• Onshore wind up 65% to 29.3 GW • Demand response up 76% to 8.8 GW	• Onshore wind up 40% to 40.9 GW
Significant Generation Changes			
	• Onshore wind up 305% to 61.4 TWh	• Onshore wind up 64% to 101.0 TWh	• Onshore wind up 40% to 141.1 TWh
Significant Net Export Changes (negative = Imports)			

Table 20. CO_2+ Scenario Significant Changes through 2030 in the Southwest Eastern Interconnection

Territory:	Southwest	Scenario:	F8S7
2015	2020	2025	2030
Significant Capacity Changes			
• Steam O/G down 69% to 8.4 GW	• Coal down 74% to 8.6 GW • Onshore wind up 2,048% to 94.6 GW • DR up 615% to 10.2 GW	• Demand response (DR) up 92% to 19.7 GW	
Significant Generation Changes			
	• Coal down 89% to 26.7 TWh • Combined cycle down 33% to 68.9 TWh • Onshore wind up 2,060% to 327.3 TWh	• Coal down 88% to 3.3 TWh	
Significant Net Export Changes (negative = Imports)			
	• Net exports up 15% to 15% of demand		

The Southwest territory (Nebraska, SPP, and Entergy) has a large increase in wind capacity in the CO_2+ scenario in 2020, sooner than the Northwest territory but with little further growth after that point (Fig. 46). In the RPS/R scenario the growth is more gradual over the study period (Fig. 45), while in the BAU scenario, wind capacity is relatively small until 2035 (Fig. 44). Coal and CC provide the bulk of generation in the BAU and RPS/R scenarios.

2.6 Southeast

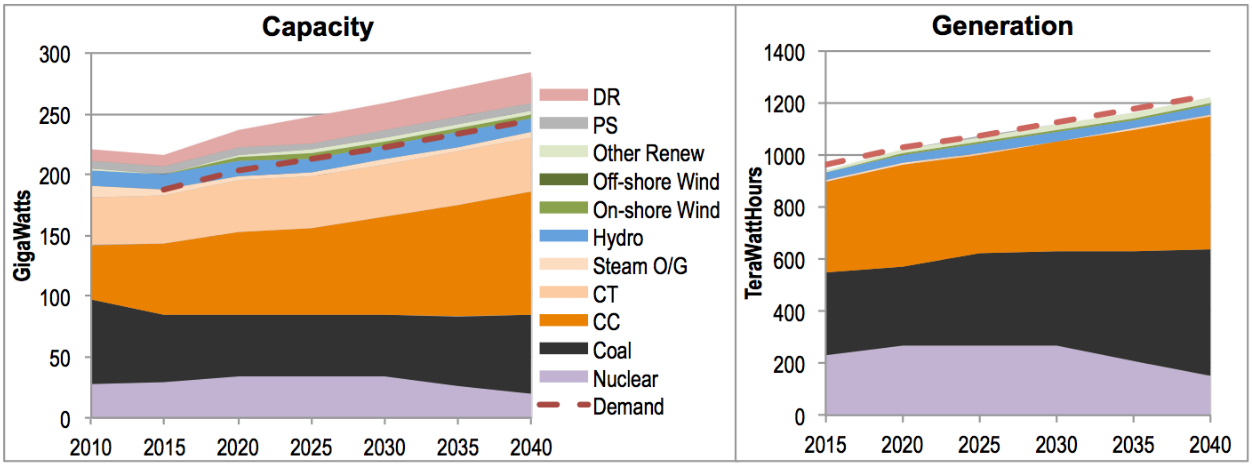


Fig. 47. BAU scenario Phase 1 capacity and generation for the Southeast Eastern Interconnection.

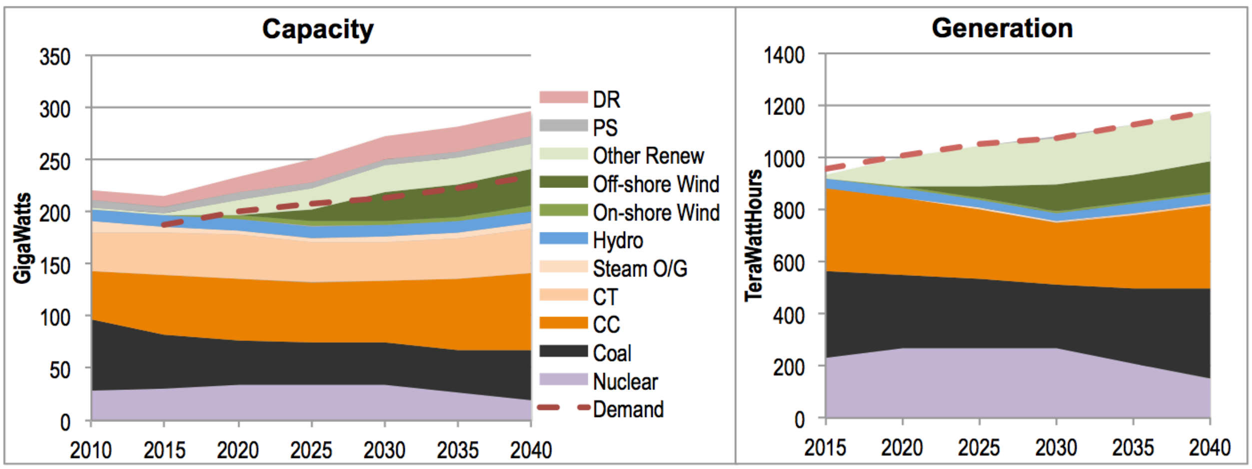


Fig. 48. RPS/R scenario Phase 1 capacity and generation for the Southeast Eastern Interconnection.

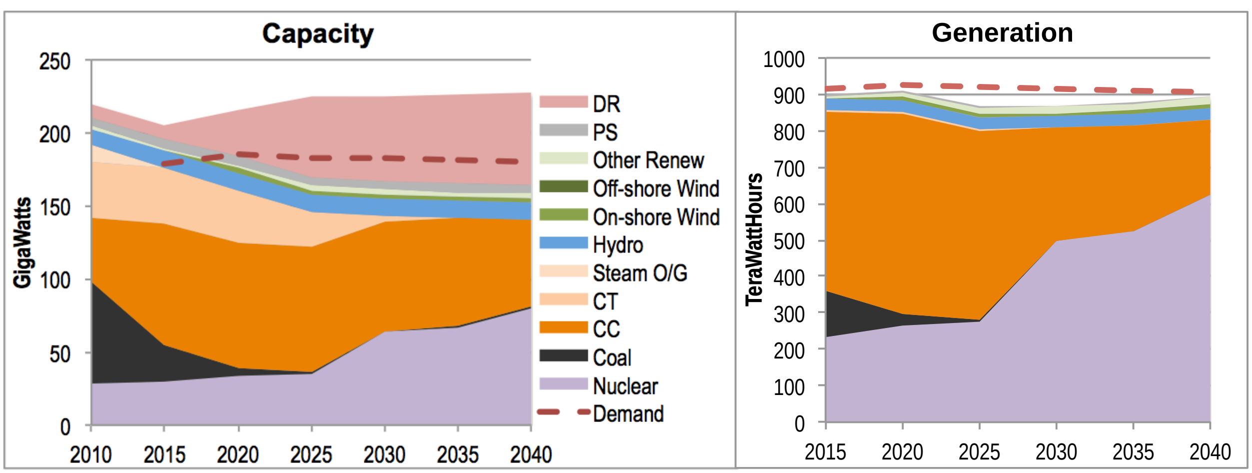


Fig. 49. CO_2+ scenario Phase 1 capacity and generation for the Southeast Eastern Interconnection.

Table 21. BAU Scenario Significant Changes Through 2030 in the Southeast Eastern Interconnection

Territory: Southeast		Scenario: F1S17	
2015	2020	2025	2030
Significant Capacity Changes			
• Combined cycle up 32% to 59.0 GW	• Demand response (DR) up 60% to 15.2 GW	• DR up 43% to 21.8 GW	
Significant Generation Changes			
Significant Net Export Changes (negative = Imports)			

Table 22. RPS/R Scenario Significant Changes Through 2030 in the Southeast Eastern Interconnection

Territory: Southeast		Scenario: F6S10	
2015	2020	2025	2030
Significant Capacity Changes			
	• Other renewables up 698% to 14.9 GW • Demand response (DR) up 60% to 15.2 GW	• Other renewables up 40% to 21.0 GW • DR up 43% to 21.8 GW	• Offshore wind up 150% to 28.5 GW
Significant Generation Changes			
	• Other renewables up 725% to 110.3 TWh	• Other renewables up 41% to 155.4 TWh	• Offshore wind up 150% to 98.7 TWh
Significant Net Export Changes (negative = Imports)			

Table 23. CO_2+ Scenario Significant Changes Through 2030 in the Southeast Eastern Interconnection

Territory: Southeast		Scenario: F8S7	
2015	2020	2025	2030
Significant Capacity Changes			
• Coal down 64% to 25.3 GW • Combined Cycle (CC) up 85% to 82.6 GW	• Coal down 80% to 5.0 GW • Demand Response (DR) up 230% to 31.2 GW	• Combustion Turbine (CT) down 32% to 24.5 GW • DR up 77% to 55.3 GW	• Nuclear up 79% to 63.6 GW • CT down 86% to 3.5 GW
Significant Generation Changes			
	• Coal down 78% to 27.6 TWh		• Nuclear up 79% to 495.1 TWh • CC down 40% to 311.6 TWh
Significant Net Export Changes (negative = Imports)			

In the CO_2+ scenario, the Southeast territory (TVA, SOCO, VACAR, and Florida) has few renewable resources but instead relies on nuclear and CC for the bulk of its capacity (Fig. 49). Nuclear expands greatly between 2025 and 2030, most notably in Florida. An interesting note is that regional capacity is insufficient for the region except for significant employment of DR. This gets reflected in the marginal prices during peak times in both Phase 1 and Phase 2. Offshore wind and other renewables are aggressively developed in the RPS/R scenario (Fig. 48), while the BAU scenario continues its reliance on nuclear, coal, and CC (Fig. 47).

3. TOPIC 3: INTEGRATED COST COMPARISON BETWEEN SCENARIOS

Costs were determined in the study through a variety of means. In Phase 1, most of the major costs were calculated within the MRN-NEEM model. In addition, other costs were calculated by either the EIPC or by working groups of the SSC. In Phase 2, the MAPS model calculated fewer categories of costs. In some instances the missing values were recalculated based on Phase 2 analysis, while in others, the Phase 1 results were simply transferred over.

Over the course of the study, costs were calculated in three formats: annual costs (either for every 5 years in Phase 1 or just 2030 in Phase 2); one-time costs over the course of the study period, such as construction costs; or levelized capital costs that provided the annual cost to recover the construction cost plus interest and other associated costs. Besides these, sub-annual or hourly costs were calculated in some circumstances, but these can be summed to annual costs. The list of costs, their sources, and formats are in Table 24.

Table 24. Types of Cost Outputs with Source and Format

Cost	Phase 1		Phase 2	
	Source	Format	Source	Format
Fuel	MRN-NEEM	Annual every 5 years	MAPS	2030 cost
Variable Oper. & Maint.	MRN-NEEM	Annual every 5 years	MAPS	2030 cost
Fixed Oper. & Maint.	MRN-NEEM	Annual every 5 years	Phase 1 adjusted	2030 cost
Capital—Generation	MRN-NEEM	Levelized every 5 years	EIPC	One-time construction cost
Capital—Transmission	EIPC	One-time construction cost	EIPC	One-time construction cost
Capital—Nuclear Uprates	EIPC	One-time construction cost	EIPC	One-time construction cost
Capital—Pollution controls	MRN-NEEM	Levelized every 5 years	EIPC	One-time construction cost
Distributed Photovoltaic	SSC	Annual and levelized	Phase 1	2030 cost
Energy Efficiency	SSC	Annual and levelized	Phase 1	2030 cost
Demand Response	SSC	Annual and levelized	Phase 1	2030 cost
Variable Generation Cost	SSC/MRN-NEEM	Annual and levelized	SSC / MAPS	2030 cost
Thermal Integration Cost	SSC/MRN-NEEM	Annual and levelized	SSC / MAPS	2030 cost
Net Imports	MRN-NEEM	Annual every 5 years	MAPS/Phase 1	2030 cost

Phase 1 costs can be put on the same basis and summed by using the annual costs, treating the levelized costs as the cost to be paid each year, and levelizing the remaining construction costs to provide an annualized amount. Costs between the 5-year increments can be interpolated as well to create an annual stream of costs. These were then discounted to create the net present value of the costs for each scenario. This method was used in reporting the Phase 1 results (EIPC 2011).

Phase 2 costs are largely either costs only for 2030 or one-time construction costs without interest, otherwise known as overnight construction costs. It is possible to scale the annual costs in other years from Phase 1 based on the relationship between the 2030 costs from the two phases for each scenario. The study conducted by Synapse, Inc. (Fagan et al. 2013) uses this method to compare the relative costs of the three scenarios for the entire EI, taking into account that emissions costs assumptions and kilowatt-hour outputs are different in each.

It would be difficult, however, to apply a consistent scaling method if looking at regional costs because regional capacity, generation, technologies, and transfers were different between the two phases. For that reason, the analysis below focuses simply on integrating the costs in the year 2030 for each region using Phase 2 results. Comparisons to Phase 1 costs in 2030 are in Figs. 26-28.

Fixed operation and maintenance (O&M) costs from Phase 1 were adjusted based on the capacity changes in Phase 2 for each technology. To convert the overnight construction costs to costs in 2030, we applied an average capital recovery factor (or fixed cost recovery factor) of 11.5% to the construction costs. Actual capital recovery factors as used in Phase 1 [Table 12 of the Input Assumptions (CRA 2010)] varied from 11.2% for nuclear plants, 11.3% for CC, and 11.8% for most other technologies. (Coal was set at 10.5% but represents little or no portion of new construction.) Because total generating construction costs were not disaggregated by type and no factor was set for transmission costs, a single representative number seemed most fitting. This value may understate the capital cost for renewables while overstating that for traditional technologies and transmission.

Net import costs represent the cost of imports into a region minus the revenues from sales out of the region. The costs are based on the sales amount and marginal cost at the time of generation. (MRN-NEEM also applies transfer and wheeling charges in the Phase 1 calculations.) In Phase 2, the hourly locational marginal prices (LMPs) were reported for 154 balancing areas (BAs) spread across the NEEM regions. These were averaged on a weighted basis across each NEEM region to determine regional marginal prices. Any transfers between regions were costed at the price in the importing region. For example, if region A during a specific hour had a marginal price of $50/MWh and the neighboring region B had a price of $60/MWh, the sales into region B would be priced at $60/MWh. This calculation is somewhat simplistic as it does not take into account bilateral trades that may be priced at a fixed cost, but rather treats all sales as a wholesale market activity.

For a given NEEM region that exports electricity, the cost of that export would be included in the fuel, variable O&M, etc. costs, but the revenue from those exports would offset those costs. Similarly, if a region imported power, it would be costed at its LMP. The final sum of costs including the net import cost will give a better representation of the total cost of power for that region.

Hydro Quebec power was modeled differently than other regions in Phase 1 and 2. In Phase 1, the import capability to different regions was modeled as pseudo-units. The resulting imports were priced based on LMPs. For Phase 2, the interchange flows were taken from Phase 1 and applied as generation sources in the various regions. To cost this power, we applied the average cost of the Hydro Quebec power from Phase 1 to the generation (which essentially matched Phase 1) so both phases had the same costs. Exports and imports to WECC and ERCOT were calculated within MRN-NEEM and MAPS. Unit costs associated with them were determined from NEEM results in Phase 1 and applied to Phase 2.

Tables 25-27 show the costs for each major territory and category in the three scenarios. Note that these do not include major costs that are common to all cases such as capital on existing assets, SSI, and base levels of DG. DR and EE expenses are those specified for 2030 and so do not include earlier years' values. Only the average values for categories that had high/low ranges are shown.

Table 25. Phase 2 Costs in 2030 for the BAU Scenario ($Billion)

	EI	Northwest	Central	Northeast	Southwest	Southeast
Fuel	85.1	12.6	19.1	6.5	12.3	34.5
Variable Operation and Maintenance (O&M)	18.4	4.1	4.7	0.9	3.4	5.4
Fixed O&M	50.3	9.5	14.8	5.7	6.6	13.7
Levelized Capital—Generation	27.9	4.5	8.0	8.8	1.7	4.9
Levelized Capital—Transmission	1.8	0.4	0.4	0.5	0.4	0.1
Levelized Capital—Other	3.1	0.7	1.0	0.1	0.5	0.8
Emissions	0.2	-	0.1	0.1	-	-
Distributed Photovoltaic	-	-	-	-	-	-
Energy Efficiency + Demand Response	1.5	0.2	0.4	0.6	0.0	0.2
Variable Generation Penalty	1.1	0.4	0.3	0.2	0.1	0.0
Large Thermal Penalty	6.2	1.0	1.7	0.6	0.9	2.1
Net Imports	1.6	(0.2)	0.5	0.9	0.1	0.2
Total	196.9	33.1	51.0	24.9	26.1	61.9

Table 26. Phase 2 Costs in 2030 for the RPS/R Scenario ($Billion)

	EI	Northwest	Central	Northeast	Southwest	Southeast
Fuel	73.8	8.5	15.4	5.6	7.7	36.6
Variable Operation and Maintenance (O&M)	15.5	3.4	3.9	0.8	2.7	4.7
Fixed O&M	54.0	9.6	15.7	5.5	7.3	15.9
Levelized Capital—Generation	78.1	11.3	24.0	8.6	10.4	23.9
Levelized Capital—Transmission	7.8	1.2	1.9	0.5	3.3	0.8
Levelized Capital—Other	2.9	0.7	0.8	0.1	0.5	0.7
Emissions	0.1	-	0.1	0.1	-	-
Distributed Photovoltaic	-	-	-	-	-	-
Energy Efficiency + Demand Response	1.5	0.2	0.4	0.6	0.0	0.2
Variable Generation Penalty	2.6	0.6	0.9	0.2	0.6	0.3
Large Thermal Penalty	5.0	0.8	1.4	0.5	0.7	1.6
Net Imports	1.4	1.3	(1.6)	1.3	0.3	0.1
Total	242.6	37.5	63.0	23.8	33.5	84.8

Table 27. Phase 2 Costs in 2030 for the CO_2+ Scenario ($Billion)

	EI	Northwest	Central	Northeast	Southwest	Southeast
Fuel	40.8	5.2	12.2	3.0	3.5	16.8
Variable Operation and Maintenance (O&M)	6.4	1.0	1.8	0.7	0.7	2.2
Fixed O&M	36.6	7.3	8.5	4.9	6.1	9.9
Levelized Capital—Generation	99.8	33.6	9.9	9.5	26.0	20.9
Levelized Capital—Transmission	11.3	4.0	2.3	1.0	3.2	0.9
Levelized Capital—Other	1.3	0.3	0.4	0.1	0.2	0.2
Emissions	45.3	7.6	15.0	2.0	5.1	15.7
Distributed Photovoltaic	13.9	3.2	2.9	1.8	3.2	2.8
Energy Efficiency + Demand Response	8.9	1.7	2.3	1.3	1.1	2.5
Variable Generation Penalty	2.9	1.2	0.2	0.2	1.2	0.0
Large Thermal Penalty	3.8	0.4	1.1	0.4	0.3	1.6
Net Imports	3.8	(3.6)	6.8	1.8	(3.8)	2.6
Total	275.0	61.9	63.4	26.7	46.8	76.2

In all scenarios, transmission capital costs represent at most 10% of the overall capital cost and less than 5% of total costs. It is likely that in those scenarios with high levels of curtailment and/or DR, additional transmission capacity would provide opportunities for lower cost power to displace high cost power. This is examined more thoroughly in Topic 7.

Total cost may be a better comparison between scenarios than cost per kilowatt-hour because demands and generation differ but the energy services are essentially the same. EE, DG, price elasticity, etc. all influence the amount of energy generated, thereby influencing the denominator. On the other hand, cost per kilowatt-hour with regional imports and exports accounted for may provide an additional perspective on the possible cost for electricity to consumers under the different scenarios. Generation costs per megawatt-hour are shown in Figs. 29-31 for each region. Figures 50–55 show the components based on demand, in billion dollars for each territory (using the data from Tables 25-27), and Figures 56 and 57 show the costs per unit of demand.

Figure 50 presents the cost summation for the entire EI in 2030. Fuel costs are highest in the BAU scenario, while levelized capital costs increase drastically in the other scenarios. Generator capital cost far outweighs the impact of transmission and other capital costs. On a straight comparison, the CO_2+ scenario has the highest cost. However, from a societal perspective, the picture is complex. Much of the top categories of costs are generally not born by the electricity sector in that EE and distributed photovoltaic (PV) costs are largely borne by end users. Large CO_2 emissions costs are only accounted for in the CO_2+ scenario, and customers do not purchase a physical resource unique to this scenario but rather the legal right to emit CO_2. Either the funds can be considered unencumbered and other societal costs (e.g., taxes) could be reduced, or they represent a damage cost that should be borne by CO_2 emissions in the other scenarios but is not. Nevertheless, the various cost impacts do serve to raise the price of electricity in this scenario thereby driving demand lower.

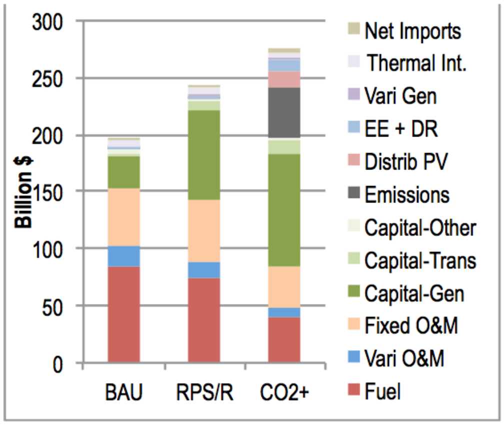


Fig. 50. Phase 2 total costs for the Eastern Interconnection in 2030.

The following figures present the cost information for each of the major territories of the EI as defined in Table 1. More detailed regional information is presented in Appendix A.

The Northwest territory (MISO + MAPP) develops a large amount of wind capacity in the CO_2+ scenario, almost 100 GW more than in the BAU scenario. The utilities, RTOs, etc. in the territory also build 15 GW more CC plants. Together, these lead to the large levelized capital cost for generating plants shown in Fig. 51. Some export revenue is returned to the region to offset some of the costs, but in Phase 2 (shown) more of the generation remained in the region than during Phase 1. Emissions costs are 11% of total costs in the CO_2+ scenario. The RPS/R scenario has some increase in capital costs due to wind and CC build-out but much less than the CO_2+ scenario. With the local preference for renewable resources and no CO_2 cost, new capacity is spread to other regions and 50 GW of coal capacity is left online. Rather than exports, the territory as a

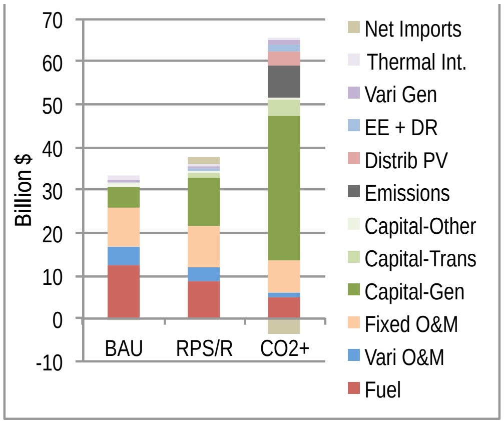


Fig. 51. Phase 2 total costs for the Northwest Eastern Interconnection in 2030.

whole imports a small amount of power. The BAU scenario has much lower capital costs, but the highest fuel cost. Coal and CC production are highest in this scenario. The corresponding graphs for each region and territory are included in Appendix A.

The Central territory (PJM and Non-RTO Midwest) has slightly lower costs in the CO_2+ scenario than the RPS/R scenario (Fig. 52). It imports power from several regions in the CO_2+ scenario, most notably the Northwest and Southwest through new HVDC lines. This territory's emissions costs are highest of all at 24% of total costs. With lower production (due to both lower demand and imports) operating and fuel costs are reduced. In the RPS/R scenario capital costs are much higher as new renewable capacity is constructed within the region to achieve the renewable portfolio standard. A small amount of generation is exported. The BAU scenario has the highest fuel and other operating costs but much lower capital costs and no CO_2 emissions cost.

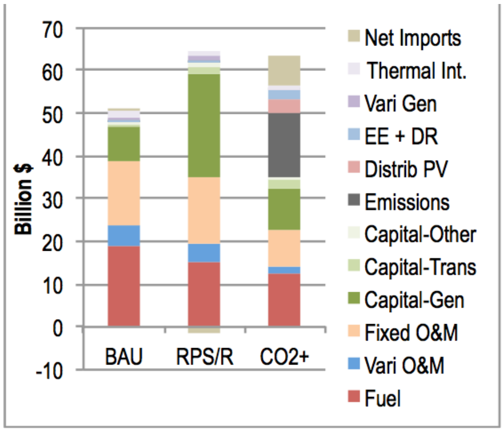


Fig. 52. Phase 2 total costs for the Central Eastern Interconnection in 2030.

The Northeast territory (New York, New England, and Ontario) has relatively similar costs in all three scenarios (Fig. 53). The CO_2+ scenario has lower fuel costs but higher capital and emissions costs. The territory also imports more power from Hydro Quebec in the CO_2+ scenario. The RPS/R scenario has the lowest overall cost with reductions in most categories. However, imports are $400 million higher. Within the territory, there is a great deal of difference in generation and cost between regions. NYISO A-F, NYISO G-I, and IESO are all net exporters, while NYISO J-K and NEISO are net importers. Hydro Quebec power flows to IESO, NYISO A-F, and NEISO, but much of it then passes on to the other two NYISO regions. NYISO J-K gets 58% to 74% of its demand from imports, comprising 45% to 55% of the total cost. These results can be seen in Appendix A.

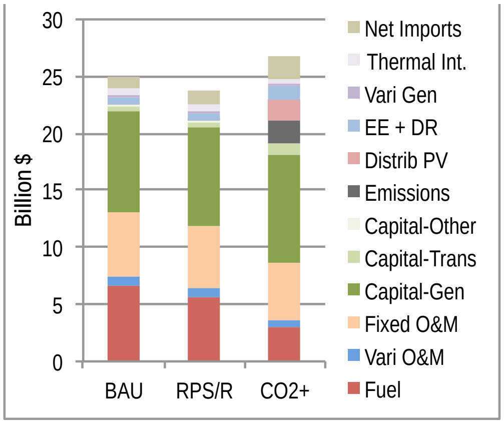


Fig. 53. Phase 2 total costs for Northeast Eastern Interconnection in 2030.

As with the Northwest territory, the Southwest territory has a large build-out of wind (94 GW more than the BAU scenario) to offset deactivations of coal, CC, and less efficient peaking plants. Although the region does export a good share of its power, much of it is used internally because the Entergy region becomes a large importer. The territory is relatively self-sufficient in scenarios 2 and 3. Wind capacity is 34 GW higher in the RPS/R scenario than the BAU scenario, and capital costs are higher accordingly. Also, both the CO_2+ scenario and the RPS/R scenario have an extensive build-out of transmission to collect the wind generation. The BAU scenario has the lowest costs, with little addition in capacity over and above the baseline for all three cases (Fig. 54). Fuel costs are higher as coal and gas are major sources.

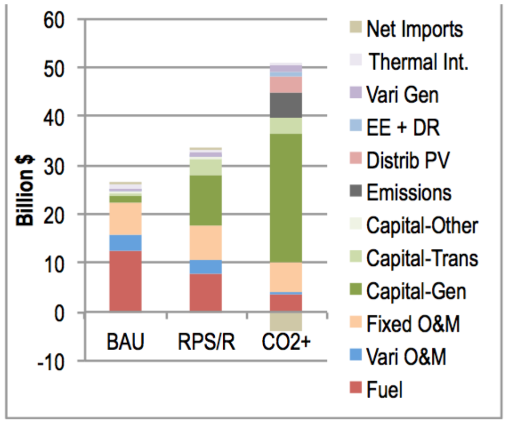


Fig. 54. Phase 2 total costs for the Southwest Eastern Interconnection in 2030.

The Southeast territory of the EI (TVA, Georgia, Alabama, Florida, and the Carolinas) has high capital costs in the CO_2+ scenario, largely from a build-out of 26 GW of nuclear power, mainly in Florida (Fig. 55). With fewer renewable resources available, the region uses nuclear power for a noncarbon resource. The region also relies more heavily on CC capacity (at 35% of total) than any other region. In the RPS/R scenario, offshore wind is developed to provide local renewable resources, despite its relatively high cost. Fuel cost is higher both because of the need for local generation and increases in biomass and other renewables.

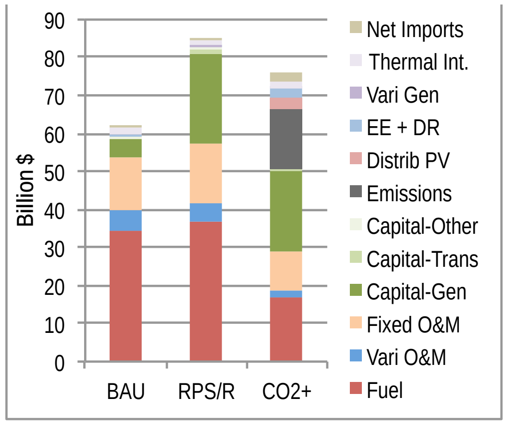


Fig. 55. Phase 2 total costs for the Southeast Eastern Interconnection in 2030.

Figure 56 shows the relative cost per megawatt-hour for each territory, dividing the total cost (including net imports) by the demand in the region. As explained above, this is closer to a comparison of what each region would pay for electricity rather than the relative cost to provide the energy services. Figure 57 uses the BAU scenario demands for each territory to lessen that distortion. However, even with a constant denominator in all three scenarios, the CO_2+ scenario is still relatively expensive. Most interesting is the cost in the Southwest and Northwest territories. There is a high capital cost for new generation, but exports only recover a portion of that. Much of the new generation is used internally within the territory. For example, the Southwest includes the exporting regions of SPPN, SPP S, and NE, while ENT is a major importer. Part of this higher cost per unit is a result of the large amount of curtailed wind power in the CO_2+ scenario for these two regions.

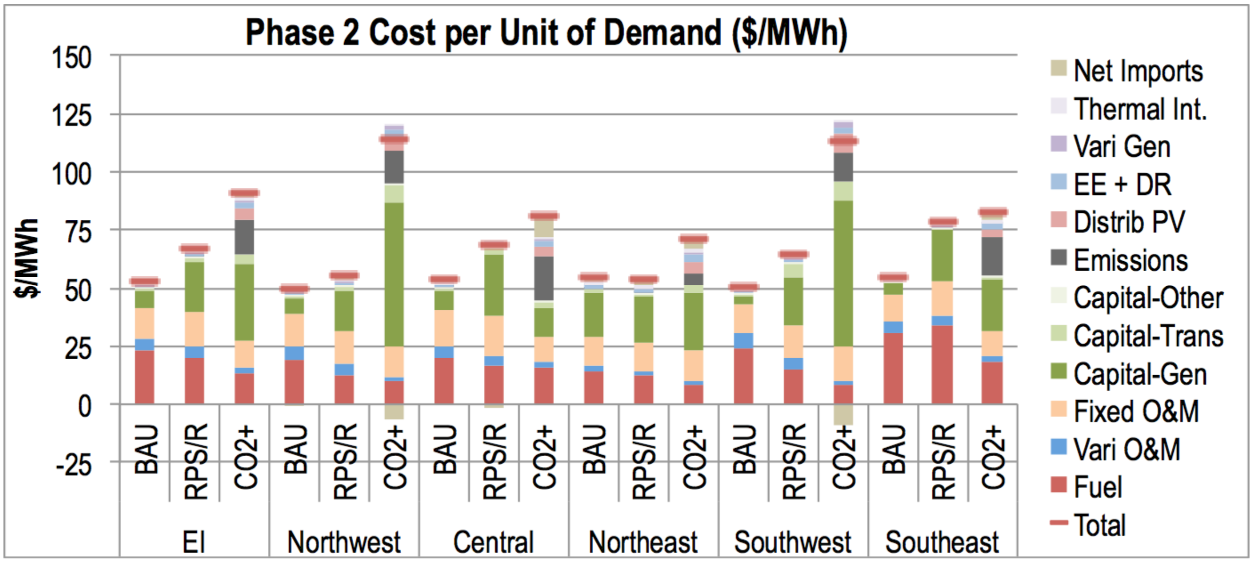


Fig. 56. Phase 2 cost per unit of demand for the Eastern Interconnection and each territory in 2030.

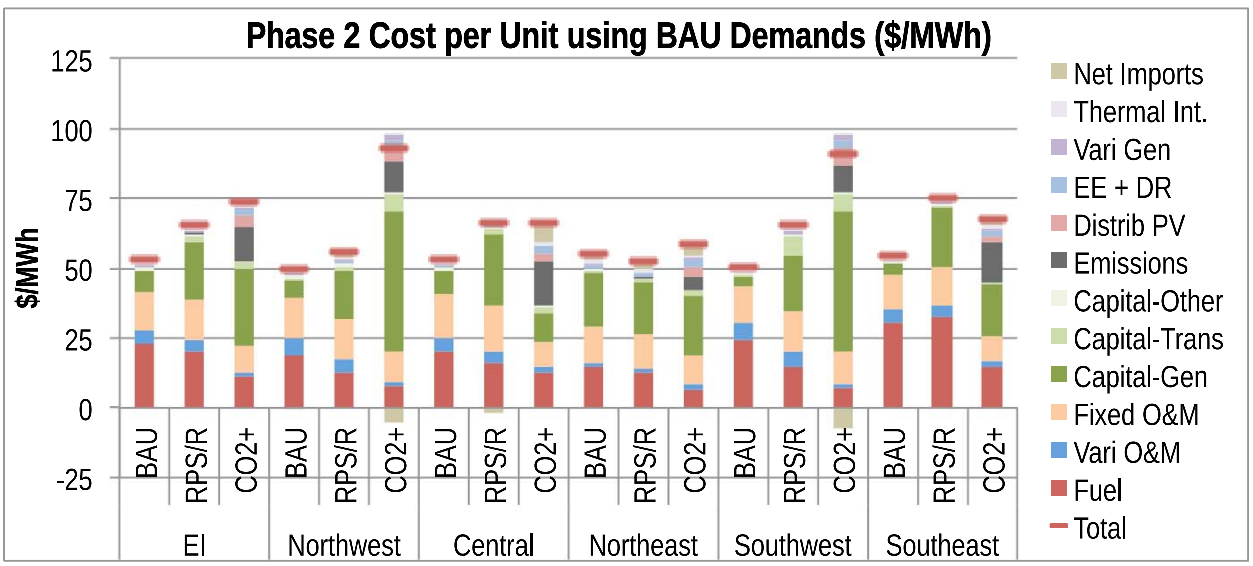


Fig. 57. Phase 2 cost per unit using the BAU scenario demands for the Eastern Interconnection and each territory in 2030.

4. TOPIC 4: REGIONAL RELIANCES

According to the Phase 2 hourly generation reports, some regions can have one technology dominate their generation over extended periods such as a week or the course of a year. Table 28 shows the most dominant generating technologies over the full year of 2030 in Phase 2 for each of the regions and territories. In the CO_2+ scenario, 11 regions have one technology provide more than two-thirds of their generation (highlighted in red). In both the RPS/R and BAU scenarios only six do. Wind is often dominant in the CO_2+ scenario, with some regions relying on nuclear or CC. The "wind regions" export a fair amount of that production but still face some issues of wind curtailment and/or high DR use. These are examined more thoroughly in Topics 7 and 8. Coal continues its dominance in the BAU but declines some in the RPS/R scenario. The CO_2+ scenario clearly shows the shift to new technologies, where CO_2 producing technologies are heavily penalized and thus production minimized.

Table 28. Most Dominant Technologies in Each Region or Territory Based on Percent of Total Generation

	BAU		RPS/R		CO_2+	
Region or Territory	**Technology**	**% Gen in 2030**	**Technology**	**% Gen in 2030**	**Technology**	**% Gen in 2030**
MAPP CA	Hydro	59%	Hydro	**96%**	Hydro	**92%**
MAPP US	Coal	53%	Wind	54%	Wind	**72%**
MISO W	Coal	51%	Wind	48%	Wind	**83%**
MISO MO-IL	Coal	**77%**	Coal	**74%**	Wind	39%
MISO WUMS	Coal	41%	Coal	47%	Comb. Cycle	44%
MISO IN	Coal	**83%**	Coal	**90%**	Wind	57%
MISO MI	Coal	45%	Coal	43%	Comb. Cycle	52%
Non-RTO Midwest	Coal	**93%**	Coal	**91%**	Comb. Cycle	**84%**
PJM ROR	Coal	53%	Coal	39%	Nuclear	39%
PJM ROM	Coal	38%	Nuclear	30%	Nuclear	46%
PJM E	Nuclear	54%	Nuclear	46%	Nuclear	57%
IESO	Nuclear	60%	Nuclear	60%	Nuclear	63%
NYISO A-F	Hydro	32%	Hydro	33%	Hydro	36%
NYISO G-I	Nuclear	49%	Nuclear	**70%**	Nuclear	**74%**
NYISO J-K	Comb. Cycle	**80%**	Comb. Cycle	**81%**	Comb. Cycle	**83%**
NEISO	Comb. Cycle	36%	Nuclear	37%	Nuclear	47%
NE	Coal	**68%**	Coal	55%	Wind	**68%**
SPP N	Coal	**75%**	Coal	54%	Wind	**85%**
SPP S	Coal	56%	Wind	47%	Wind	**81%**
ENT	Comb. Cycle	42%	Comb. Cycle	36%	Nuclear	51%
TVA	Coal	40%	Nuclear	34%	Nuclear	47%
SOCO	Coal	37%	Coal	32%	Nuclear	46%
VACAR	Nuclear	41%	Nuclear	37%	Nuclear	62%
FRCC	Comb. Cycle	61%	Comb. Cycle	54%	Nuclear	**69%**
Northwest	Coal	55%	Coal	48%	Wind	53%
Central	Coal	46%	Coal	33%	Nuclear	41%
Northeast	Nuclear	41%	Nuclear	43%	Nuclear	50%
Southwest	Coal	52%	Coal	42%	Wind	**66%**
Southeast	Comb. Cycle	34%	Nuclear	27%	Nuclear	57%
EI	Coal	38%	Coal	30%	Nuclear	37%

Figure 58 provides these data in a chart showing the dominant resource for each region for each of the scenarios. The first column in each grouping is the BAU, the second is the RPS/R, and the third is the

CO_2+. Note that coal dominance in BAU and RPS/R often switches to wind in the CO_2+ scenario. Nuclear is relatively dominant in a number of regions though rarely more than 50% of the total.

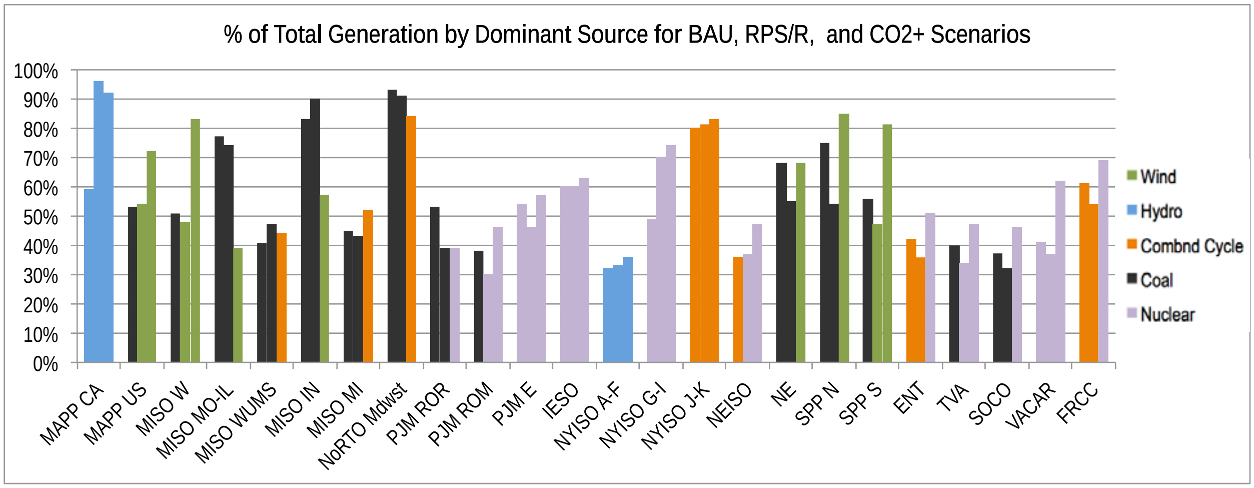


Fig. 58. Dominant generation source for each region and scenario.

Another indicator of domination by a single technology is how many days in a year certain technologies provide the overwhelming share of generation. Even in regions that do not have a dominant technology over the entire year, there may be periods of time when the region is highly reliant on a single one. Tables 29–31 show the number of days in 2030 that one technology provides more than 80% of the generation in at least 20 of the 24 hours of the day.

Table 29. Number of Days that Technology Dominates Region's Generation in the BAU Scenario in 2030

	Coal	Combined Cycle
MISO IN	162	-
MISO MO-IL	45	-
NE	3	-
Non-RTO Midwest	360	-
NYISO G-I	-	3
NYISO J-K	-	269
SPP N	27	-

Table 30. Number of Days that Technology Dominates Region's Generation in the RPS/R Scenario in 2030

	Nuclear	Coal	Combined Cycle	Hydro	Wind
MAPP US	-	-	-	-	18
MISO IN	-	339	-	-	-
MISO MO-IL	-	24	-	-	-
MISO W	-	-	-	-	3
Non-RTO Midwest	-	360	-	-	-
NYISO G-I	15	-	-	-	-
NYISO J-K	-	-	281	-	-
SPP N	-	2	-	-	4
MAPP CA	-	-	-	348	-

Table 31. Number of Days that Technology Dominates Region's Generation in the CO_2+ Scenario in 2030

	Nuclear	Combined Cycle	Hydro	Wind
ENT	47	-	-	-
FRCC	13	-	-	-
MAPP US	-	-	-	101
MISO IN	-	-	-	40
MISO W	-	-	-	181
NE	-	-	-	15
Non-RTO Midwest	-	243	-	-
NYISO G-I	31	-	-	-
NYISO J-K	-	178	-	-
SPP N	-	-	-	157
SPP S	-	-	-	111
VACAR	4	-	-	-
MAPP CA	-	-	310	-

Note that in the CO_2+ scenario, wind is a dominant provider for more than 15 days in six different regions. All of the regions located along the western part of the EI have numerous days where wind is the main contributor. Nebraska (NE) is reduced because they have two nuclear plants that continue to provide baseload noncarbon electricity. Four regions have nuclear providing a dominant share on multiple days. These are regions that do not have significant renewable resources. Lastly, two smaller regions use CC plants for much of their generation. They either have converted their coal to gas production or have few other resources available.

In the RPS/R scenario coal continues to be viable and dominates in several regions, especially two regions in the Midwest (MISO IN and Non-RTO Midwest) that currently have high coal market share. Hydro is a major component of MAPP Canada as it builds additional capacity for the RPS market. In the BAU scenario, coal dominates more regions because there is less renewable development, although current projected US Environmental Protection Agency (EPA) regulations continued to be modeled in this scenario as in the others. CC generation dominates in NYISO J-K (NYC and Long Island) in all three scenarios.

5. TOPIC 5: GAS USE

Many people expect that the amount of natural gas used for generation will increase significantly in the coming years. The rapid increase in availability of shale gas has lowered the prices for natural gas, making it a viable broadscale source of baseload power. One topic of interest to EISPC members was how much growth was projected by the EIPC cases. Regionally, might the growth be significantly more than current amounts such that the current infrastructure might need rapid expansion to handle the growth?

While natural gas prices in the EIPC cases were projected to moderate from previous years' estimates, they did not take fully into account the current drop in prices. Figure 59 is a graph of the prices as used in the cases, based on the DOE Energy Information Administration's (EIA's) 2011 *Annual Energy Outlook* (AEO) early release reference case (EIA 2011a). Also on the graph are EIA projections from other years, including the AEOs from 2010, 2012, and 2013. Note how the 2013 estimate has natural gas prices by 2030 roughly 20% ($1.27) lower than the price used for the EIPC study. The "low gas price" sensitivities in Phase 1 used a constant price of $4.50 for the entire period, while the "high gas price" sensitivities had a gradual shift from the AEO 2011 early release price to the AEO 2010 price by 2025 and the AEO 2010 price for all subsequent years. This equaled $8.20 in 2030. So the current expected gas prices were bounded by the high and low sensitivities in 2030, although the AEO 2013 prices are below the low gas sensitivity through 2022.

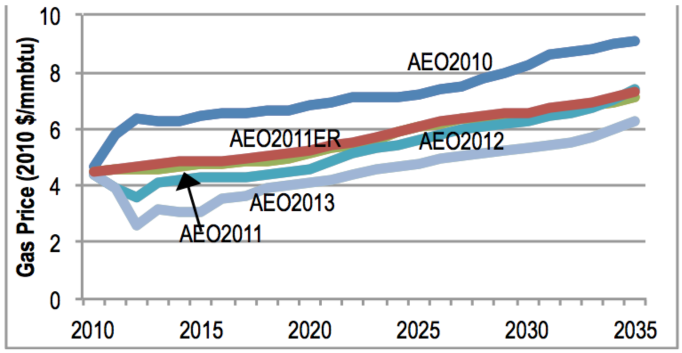


Fig. 59. Henry Hub gas prices from the DOE *Annual Energy Outlook* (AEO) of different years.

5.1 Gas Trends in Scenarios

Natural gas use for electricity in the EI started at about the same level in the BAU and RPS/R scenarios, 5.3 quadrillion Btu (Quads) in the BAU scenario and only 4.9 Quads in the RPS/R scenario (Fig. 60). Demands were slightly lower in the latter, and less CC generation was used. Gas use stayed flat and then declined further in the RPS/R scenario because coal generation remained economic while renewable generation increased its percentage, squeezing gas use. In the CO_2+ scenario, gas use in 2015 is 7.2 Quads, 38% more than in the BAU. Even at the beginning of the study period, CO_2 costs cause the conversion of coal to natural gas generation, and gas generation continues to grow to 8.4 Quads by 2020. However, by 2028 or so, the reduction in demand in the CO_2+ scenario lowered gas use to below that of the BAU scenario.

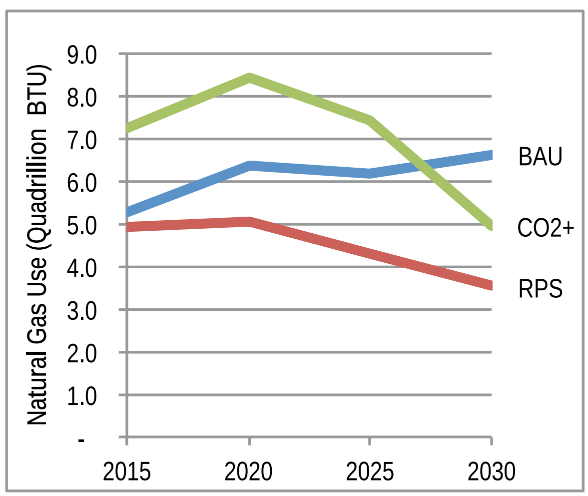


Fig. 60. Gas use for electricity in the Eastern Interconnection as a whole.

5.2 Regional Gas Use

As expected, natural gas use changes over time and is highly dependent on the scenario studied. Figures 61–63 show the gas use from Phase 1 for 2015–2030 for each scenario. In addition, they show the estimated gas use for 2030 from Phase 2 (right side of the graphs). Some of the key region results are named in the graphs, with the rest of the regions shown as fainter lines.

In the BAU scenario (Fig. 61), most regions have a relatively flat amount of natural gas use over the period. FRCC had continued growth as CC plants were used to provide additional power. PJM ROR had less CC generation in Phase 2 than Phase 1 (Fig. 9), resulting in lower gas use.

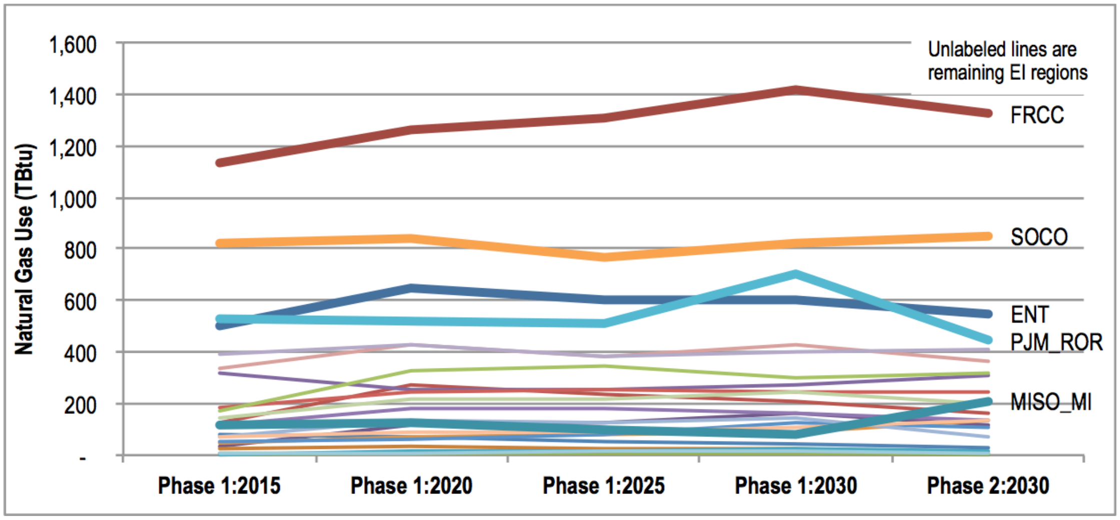


Fig. 61. Natural gas use in the BAU scenario.

In the RPS/R scenario (Fig. 62), most regions had relatively flat or declining growth in gas use as renewables gradually assumed a larger share of the market. Some regions, such as PJM ROR and MISO MI, had higher gas levels in Phase 2 than Phase 1. Their CC generation was higher in Phase 2, although a small portion of their overall generation (Fig. 10.)

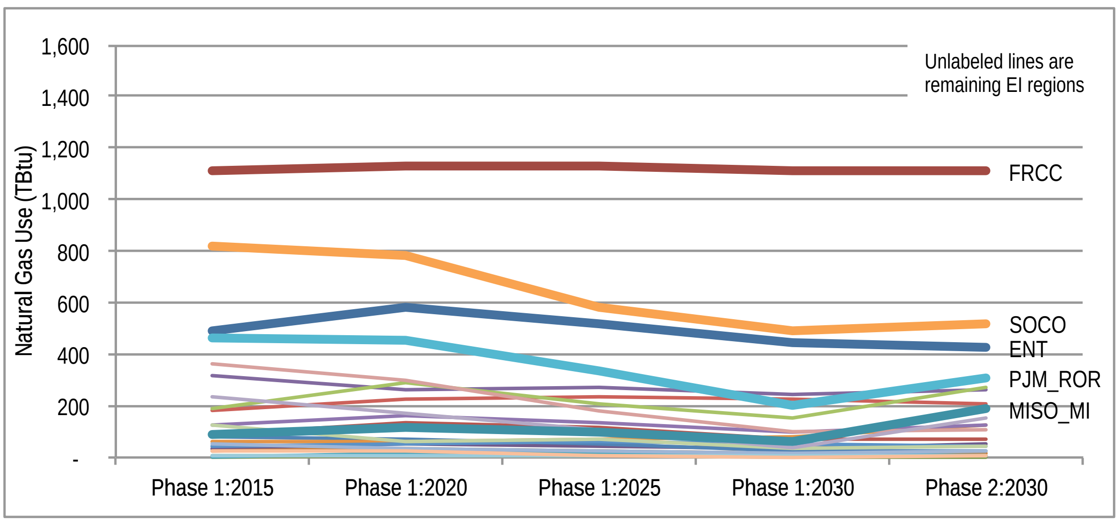


Fig. 62. Natural gas use in the RPS/R scenario.

In the CO_2+ scenario (Fig. 63), all of the regions showed declines in gas use between 2025 and 2030 as gas production decreased while other resources increased, due largely to the increase in CO_2 costs. Most notable was the drop in FRCC; the region had a large increase in nuclear capacity between those years that supplanted much of the gas generation. PJM ROR and SOCO were other large users in gas. While most regions saw roughly the same amount of gas use in 2030 from both Phase 1 and 2, a few saw significant changes. MISO IN had the biggest difference, as can be seen by the slope of the line between the last two points. In Phase 2, that region received a good amount of its power from MISO W through PJM ROR from the HVDC lines, resulting in lower internal generation (Fig. 11.)

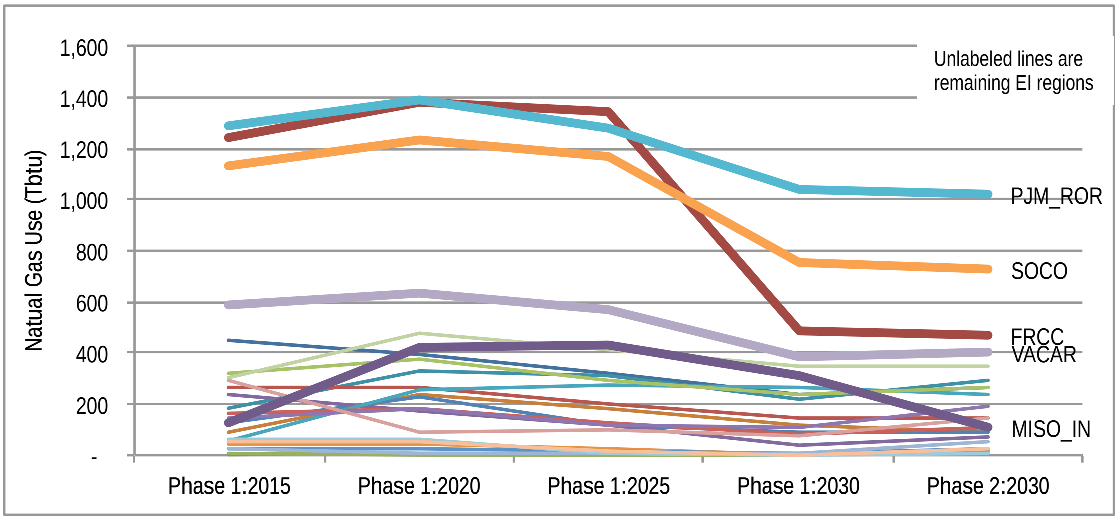


Fig. 63. Natural gas use in the CO_2+ scenario.

Many people may be surprised by the great amount of natural gas used in FRCC in the three scenarios. CC plants are the dominant supply for most years except by 2030 in the CO_2+ scenario, where nuclear became a major source. The region has historically been a high gas user since it is relatively far from coal sources while having more available access to natural gas from the Gulf.

5.3 Key Reliances

While there does not appear to be a large growth in gas use between 2015 and 2030 (−32% in the CO_2+ scenario, −29% in the RPS/R scenario, +26% in the BAU scenario), the other question raised was whether there were key times in a year when natural gas was a critical source of power. Did natural gas use spike at certain times so that while the annual amount was low, the relative amount was high for certain days?

This is somewhat the converse of the analysis in Chapter 4 (Topic 4). In that chapter we showed that CC technology dominated in only NYISO J-K for all three scenarios. This region, New York City and Long Island, has limited alternative technologies available. The other major sources there are peaking plants, and they are largely fueled by natural gas as well. Imports provided almost all of the rest of the power needed. In the CO_2+ scenario, CCs also provided a large portion of supply for the Non-RTO Midwest, since the region's coal plants were largely converted to gas. In FRCC in the BAU scenario, natural gas played an important role as the main source of new production. Nevertheless, in that scenario gas use only rose by 25% over a 15-year period.

Those regions that have low relative levels of natural gas use generally have their peak amounts occur in the peak months of July and August. During this time CT and other peaking capacity is needed. In the CO_2+ scenario, no region required more than 10% of its total gas in a single week and no region used more than 21% of its annual demand in a 3-week period. In the RPS/R scenario, the western regions had the largest spike in gas use (during mid-July). MAPP US used 56% of its annual amount in the middle 3 weeks of July, with MISO W and NE at 48% and SPP N at 38%. The BAU scenario had similar spikes in gas demand, with MAPP US needing 54% of its annual gas, Nebraska 45%, and both MISO W and MISO MO-IL 39%. None of these regions was among the highest gas users, so it is unclear whether they would feel some constraints during this time.

6. TOPIC 6: OPERATING AND PLANNING RESERVES

6.1 Reserves Definitions

Reserves represent an amount of capacity above demand available to provide adequate electricity at the correct voltage and frequency to maintain the grid under unusual or abnormal circumstances. Two main types of reserves were used in the EIPC study: planning reserves and operating reserves. They each have different purposes and definitions, but the distinctions are often lost in discussions.

Planning reserves are used for long-term resource planning and defining regional planning reserve margins. These were discussed at length in the EISPC-sponsored white paper *The Economic Ramifications of Resource Adequacy White Paper* (Astrape 2013). NERC publishes the standards for all regions on its website (NERC 2013). Most regions begin with a reliability criterion such as 1 day of outages in 10 years, but there are a number of variations on how this is calculated. The regions then determine the reserve margin required to meet that criterion. For example, the ReliabilityFirst Corporation region includes the following requirements (among others), as listed in Standard BAL-502-RFC-02 of the NERC reliability standards.

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall [Violation Risk Factor: Medium]:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin). (NERC 2013)

In this example, the planning reserve margin is to meet the 1-day-in-10-year loss of load probability; load lost through utility-controlled DR (direct load control and interruptible rates) will not be counted as loss of load for the probability, and the reserve margin is applied to the median forecast peak load to determine the number of megawatts needed for the region. Planning reserve margins were included in NEEM in Phase 1.

In Phase 2, the GE MAPS model used operating reserves or its subset spinning reserves as a key variable. These reserves are needed on an ongoing basis and vary as demand and other factors come into play. The NERC "Glossary of Terms" in the NERC reliability standards (NERC 2013) defines the different reserves, shown in Table 32. Note that the terms include two definitions for spinning reserves. In one, only unloaded generation is included, but in the second, load fully removable from the system is included as well. This distinction plays a role in the results from Phase 2.

As a complement to operating reserves, the NERC standards also define "contingency reserves" (Standard BAL-002-1). These reserves "may be supplied from generation, controllable load resources, or coordinated adjustments to interchange schedules." (R1). The contingency reserves are a mix of the operating reserves—spinning and the operating reserves—supplemental, as defined in Table 32. Both of these must be capable of being synchronized to the grid within the "disturbance recovery period."

Elsewhere in the standards the default value for the period is set at 15 min, although individual interconnections are allowed to set alternatives with approval of the NERC Operating Committee.

Table 32. NERC Definitions of Reserves (NERC 2013)

NERC Term	Definition
Operating Reserve	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and nonspinning reserve.
Non-Spinning Reserve	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Spinning Reserve	Unloaded generation that is synchronized and ready to serve additional demand.
Contingency Reserve	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Operating Reserve—Spinning	The portion of Operating Reserve consisting of • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve—Supplemental	The portion of Operating Reserve consisting of • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

6.2 Planning Reserves in Phase 1

Phase 1 of the EIPC study used planning reserve margins, with each region supplying its requirement (Table 33). MRN-NEEM took into account reserve margins for individual regions and for collections of regions into larger regions, such as MISO* and NYISO. MRN-NEEM covers all of the United States and Canada, so reserve margins were defined for regions inside and outside of the EI.

Table 33. Reserve Margin Regions, Reserve Requirements, and NEEM Regions (CRA 2010)

Reserve Margin Area	Reserve Requirement	NEEM Regions
ALB	18.0%	ALB
AZ-NM-SNV	15.7%	AZ-NM-SNV
BC	18.0%	BC
CA	16.6%	NP15
		SP15
ENT	14.0%	ENT
ERCOT	NA	ERCOT
FRCC	16.0%	FRCC
MAPP US	14.0%	MAPP US
MAPP CA	12.0%	MAPP CA
MISO	17.4%*	MISO IN

*Note: Refer to Table 1 or the Eastern Interconnection regions list at the front for complete definitions of region identifiers used in the figures, tables, and text.

Table 33 (continued)

Reserve Margin Area	Reserve Requirement	NEEM Regions
		MISO MI
		MISO MO-IL
		MISO W
		MISO WUMS
NEISO	16.0%	NEISO
Non-RTO Midwest	14.0%	Non-RTO Midwest
NWPP	18.0%	NWPP
NYISO	16.5%*	NYISO A-F
		NYISO GHI
		NYISO JK
NYISO GHI JK	-5.0%	NYISO GHI
		NYISO JK
NYISO JK	-8.0%	NYISO JK
OH (IESO)	17.0%	OH
PJM	15.3%*	PJM E
		PJM ROM
		PJM ROR
PJM E	-2.2%	PJM E**
RMPA	14.0%	RMPA
SOCO	14.0%	SOCO
SPP	13.6%	NE
		SPP N
		SPP S
TVA	15.0%	TVA
VACAR	14.0%	VACAR
**** Based on coincident peak in reserve margin area. For PJM, CRA applied a diversity factor to the noncoincident peaks.***		
***** For purposes of the study, set equal to actual 2010 Reserve Margin***		

For planning reserve margin calculations, all generating capacity qualified to meet the reserve margin, including DR. However, the EIPC applied a fractional resource contribution credit to intermittent generation (wind and solar). The installed capacity of the technology is multiplied by this fraction to represent the amount of capacity that will be available during the peak period. The amount can vary depending on the type of technology and quality of resources in the region. Solar generation is set at 30% to reflect that the peak time is likely on a hot, sunny day, but often later in the day when the sun is not at full strength. Offshore wind is set similarly based on expectations for future installations. Onshore wind generation is set lower to reflect that its generation during the peak can be lower than its average generation because winds are often calmer on the hottest, highest demand days. Table 34 lists the credit factors for each region as used in Phase 1 of the study.

An important consequence of the capacity credit is that wind generation on average is higher than its credit, yet a region will build its combined total capacity to meet the reserve margin using the lower value. This means that there will be significant generation capacity above what is needed, and even with the low capacity factors of intermittent renewables (25%–40%) there should be a number of hours in which there is substantial low or zero variable cost renewable power being generated. If this power cannot be absorbed within its own region, it will be exported if tie-line capacity is available. In Fig. 64 the CO_2+ scenario generating capacities for each major region are shown as a fraction of the region's peak demand. In it, the intermittent generation (solar, wind) have been split into two categories; the amount credited toward the reserve margin is shown immediately above the hydro capacity, while the remaining wind and solar capacity are shown on the top of each column. MAPP US, MISO, and SPP have significant amounts of capacity above the required amounts. This power is available for internal use or export if it is being produced and transmission capacity is available. If the production cannot be used then the plants must be curtailed, with loss of revenues to plant owners and loss of low-cost power to users. This was a significant issue in the CO_2+ scenario, as described in Chapter 3.

Table 34. Intermittent Resource Contributions (CRA 2010)

NEEM Region	Technology	Reserve Contribution
All Regions	Photovoltaic	30%
All Regions	Solar Thermal	30%
All Regions	Offshore Wind	30%
California	Wind	25%
Canada	Wind	20%
ERCOT	Wind	9%
New York	Wind	15%
PJM (-E, -ROM, -ROR)	Wind	13%
SPP	Wind	15%
TVA	Wind	12%
IESO	Wind	11%
MAPP CA	Wind	11%
All Other Regions	Wind	15%

Another note of interest is that, at least for the CO_2+ scenario (Fig. 64), the line representing 100% of peak demand passes through the capacity from DR. While many regions will import from the wind-rich areas to avoid use of DR, those regions far from wind sources (e.g., VACAR, FRCC) need to use DR for some of their peak hours. This does not occur in the BAU or RPS/R scenarios as DR is not as significant a fraction of the capacity contribution to the reserve margin for these two scenarios.

The RPS/R and BAU scenarios also do not have the large surpluses of wind that were in the CO_2+ scenario (Figs. 65 and 66). In the RPS/R scenario, MAPP US continues a high proportion of wind to demand to supply the rest of the Northwest. MISO and SPP have much lower surplus wind capacity because they do not have the transmission capability to export to the east. PJM and VACAR increase their surplus wind capacity to help meet RPS requirements for their regions. The BAU scenario has relatively little excess capacity because RPS requirements are not expanded beyond current state regulations.

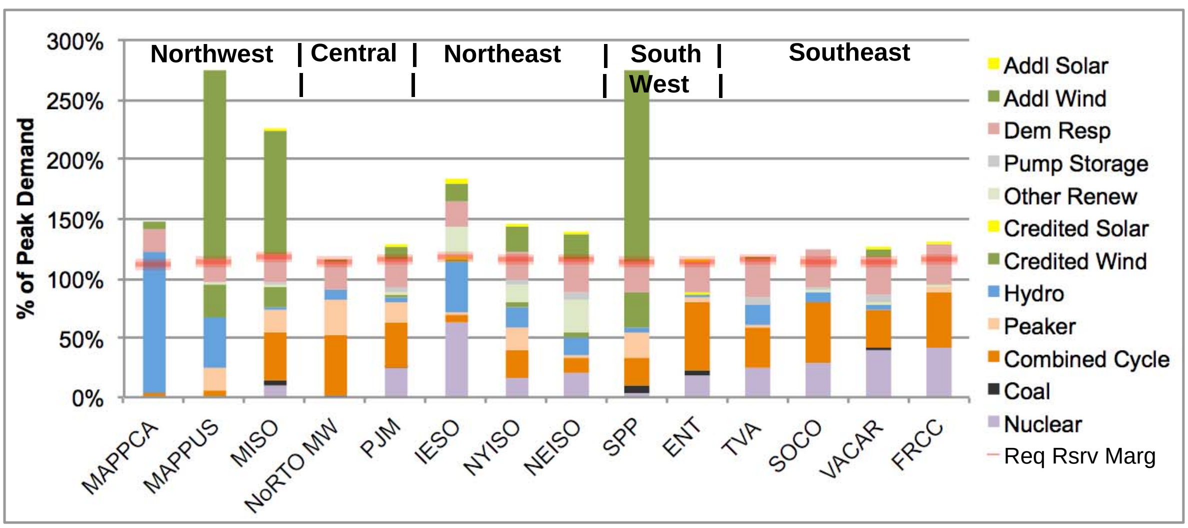


Fig. 64. Phase 1 ratio of capacities to peak demand in the CO_2+ scenario.

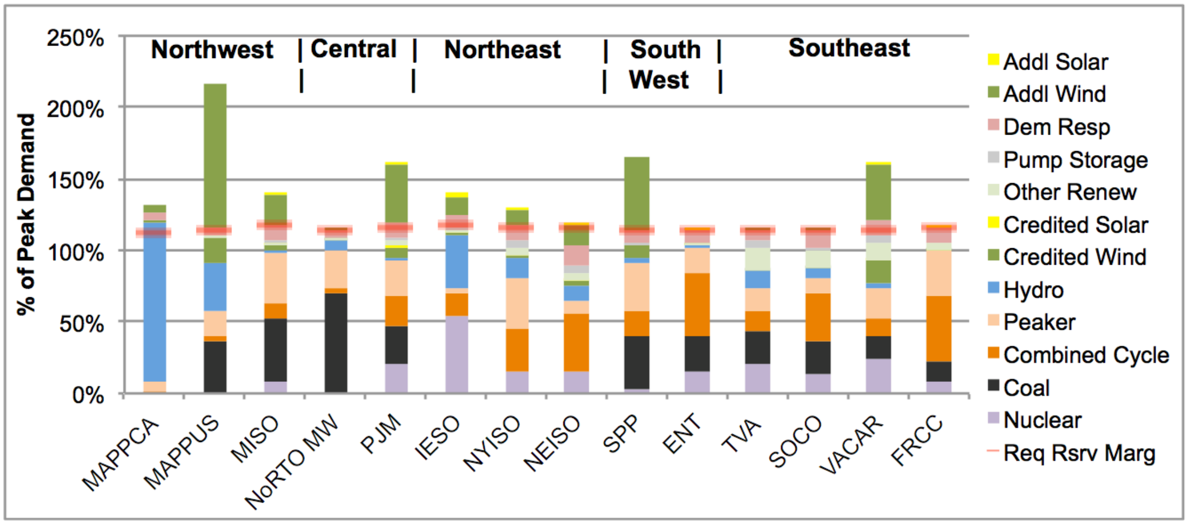


Fig. 65. Phase 1 ratio of capacities to peak demand in the RPS/R scenario.

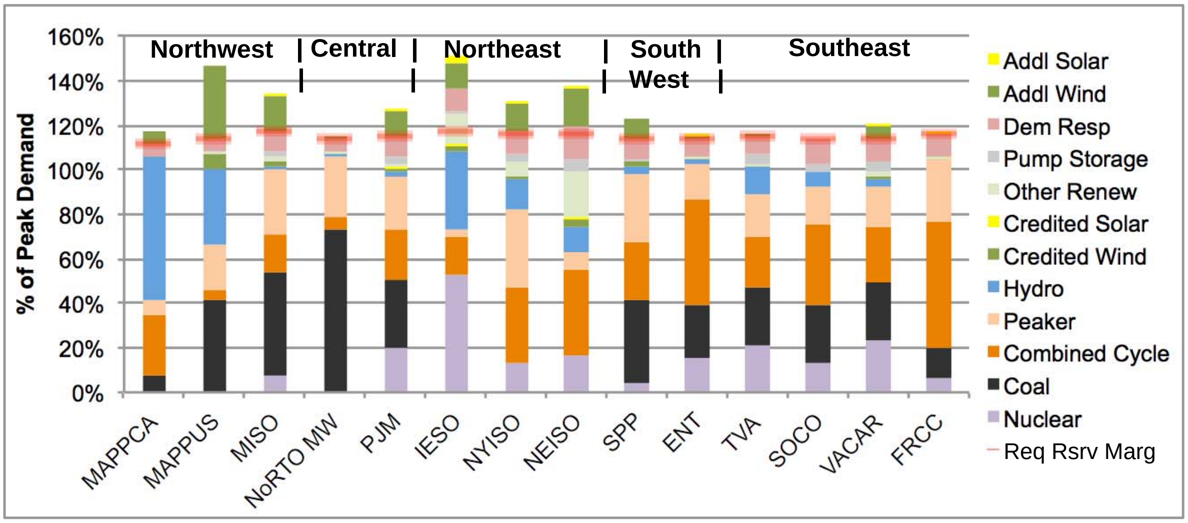


Fig. 66. Phase 1 ratio of capacities to peak demand in the BAU scenario.

Figures 65 and 66 include lines on each column showing the planning reserve margin for each region. One question raised early in the EIPC study was whether NEEM would force capacity down to the reserve margin in each year or would leave capacity higher than the minimum if it was cost-effective overall. This could happen if one region had a lower cost resource that it could use for export to other regions. At the same time, the importing regions still must have sufficient capacity to meet their internal reserve margins unless they have formal reserve sharing agreements. The CO_2+ scenario allowed reserve sharing between the southwest and southeast territories and between the northwest and central territories. In the RPS/R scenario a more regional condition was set, with each territory required to meet its requirements internally. (Hydro Quebec power could be counted for NYISO and NEISO in all cases.)

Examining the results, it is clear that NEEM did allow capacity to be higher. Table 35 shows the reserve requirement in 2030 for each consolidated region and the actual reserve margin for each of the three final cases studied. In the BAU scenario, almost all regions were at their minimum requirement, but in the subsequent scenarios some regions had higher margins as needed for minimizing costs.

Table 35. Phase 1 Reserve Requirement and 2030 Reserve Margins by Region

Reserve Margin Area	Reserve Requirement	2030 Reserve Margin		
		BAU	RPS/R	CO_2+
MAPP CA	12.0%	12.0%	26.2%	40.8%
MAPP US	14.0%	14.0%	15.9%	15.5%
MISO	17.4%	17.4%	17.4%	20.1%
Non-RTO Midwest	14.0%	14.0%	14.0%	14.0%
PJM	15.3%	15.3%	19.9%	15.3%
IESO	17.0%	23.7%	25.5%	43.3%
NYISO	16.5%	16.5%	16.5%	18.9%
NEISO	16.0%	19.3%	20.4%	16.0%
SPP	13.6%	13.6%	13.6%	13.6%
ENT	14.0%	14.0%	14.0%	14.0%
TVA	15.0%	15.0%	15.0%	15.0%
SOCO	14.0%	14.0%	14.9%	23.5%
VACAR	14.0%	14.0%	21.0%	17.3%
FRCC	16.0%	16.0%	16.0%	28.1%

6.3 Operating Reserves in Phase 2

In Phase 2, the focus in the GE MAPS modeling was on spinning reserves rather than planning reserves. The amounts for each region were based on the EIPC members' stated requirements for each, taking into account loss of the single largest generator, largest generator plus half of the second largest, or percentage of demand. Table 36 is from the Phase 2 final report (EIPC 2012). NYISO includes requirements both for the region as a whole (600 MW) and for subregions (300 MW for zone J-K, 0 MW for zone K). PJM similarly has requirements both for the mid-Atlantic region and the full region. Note that the PJM region has the largest reserve requirement. With a peak demand of 137 GW, its spinning reserve at peak is 11.8 GW, 7.6 times that of SOCO, the next largest, at its peak.

Table 36. Phase 2 Spinning Reserve Requirements

GE MAPS Commitment Pool	GE MAPS Operating Reserve Group	Spinning Reserve Requirement	Spinning Reserve Amount at Peak
NEISO	NEISO	530 MW	530 MW
NYISO	Long Island	0 MW for NYISO-K (Long Island)	0 MW
NYISO	East NY	300 MW for NYISO-G ~ NYISO-K	300 MW
NYISO	NYISO	600 MW for NYISO-A ~ NYISO-K	600 MW
PJM	PJM Mid Atlantic	1150 MW + 7.5% of load	4,844 MW
PJM	PJM RTO	1509 MW + 7.5% of load	11,785 MW
Midwest	MISO	800 MW	800 MW
TVA	TVA	625 MW	625 MW
SPP	SPP	983 MW	983 MW
VACAR	VACAR	2% of hourly load	958 MW
SOCO	SOCO	3% of hourly load	1,542 MW
FRCC	FRCC	350 MW	350 MW
IESO	IESO	225 MW	225 MW

Another factor was the technologies that qualified as spinning reserve and the quantity available from them. According to the Phase 2 documentation (EIPC 2012), only coal, gas/oil steam, CC, and hydro units were available to provide spin. The amount of spin available was calculated on a unit-by-unit basis. The maximum spin from thermal plants was limited to the lesser of the amount of capacity above their minimum amount and 10 times their per minute ramp rate (to reflect a 10 min response.) Because the ramp rates used were 3 MW/min for coal, 6 MW/min for oil/gas steam, and 10 MW/min for CC, the maximum spin was 30 MW from coal units, 60 MW from oil/gas steam, and 100 MW from CC. Also, the reserves were limited to 50% of the unit's capacity.

As an example, a 600 MW CC plant has a minimum capacity of 300 MW. So to provide the maximum 100 MW of spin it must operate at a minimum of 300 MW. To provide 10,000 MW of spin for PJM, assuming 600 MW CC plants, there would need to be 30 GW of CC plants operating. Using this formula, smaller units of 200 MW could run at their minimum of just 100 MW and still provide 100 MW of spinning reserve. (Note: The capacity and operations of specific plants are not available from the results reported, so it is not possible to determine which plants provided spinning reserves.)

Besides thermal plants, hydro plants could provide spinning reserves equal to 50% of the difference between the plant's capacity and the month's average generation. So for example, a 300 MW hydro plant operating at 100 MW on average for a given month could provide 100 MW of spin. For many of the regions, hydro capacity could provide a large portion of the spin requirement. Table 37 shows the amount of spin required and available by month for the CO_2+ scenario. Six of the regions have sufficient hydro to provide all of their spinning reserve; two others have more than half provided by hydro. Only PJM and FRCC require significant spinning reserve from thermal resources.

Table 37. Regional Average Spin Requirements and Contributions from Hydro

	NEISO	NYISO	PJM	MISO	TVA	SPP	VACA	SOCO	FRCC	IESO
Average Spin Required	530	600	7,665	800	625	983	520	889	350	225
Average Spin from Hydro	1,303	652	1,621	632	1,507	527	596	1,324	24	2,320
Ratio	246%	109%	21%	79%	241%	54%	115%	151%	7%	1031%

One sensitivity was run on the CO_2+ scenario that relaxed several variables relative to reserve requirements. The "Hi-Spin" sensitivity implementation included the following.

- Reduce spinning reserve requirements in MISO, SPP, PJM and Ontario by 50%.
- All CC units were modeled with a 100 MW/min ramp rate, turndown 14% of base load, minimum runtime, and downtime of 2 h.

Ontario already met all spin requirements from hydro, so the changes had no effect on it. MISO, SPP, and PJM received some of their spin requirements from thermal plants, so a change in their generation was expected because of these modifications. The second step in the sensitivity greatly increased the flexibility and amount of spin from CC plants. Plants could provide up to 1,000 MW of spin based on the new ramp rate, which effectively eliminated that restriction. The earlier example of a 600 MW CC plant could operate as low as 84 MW while providing 300 MW of spin (half of its capacity), so 10,000 MW of spin would only need 2,800 MW of CC operating at minimum power. This is less than 1/10 of the amount needed under the original specification. Furthermore, the minimum runtime and downtime of 2 h are much less than the base case values of 6 h and 8 h for minimum runtime and downtime. These combined changes reduced the need for CC plants and also allowed for their shut down when not needed much more frequently. This resulted in less forced curtailment of wind generation, as discussed in the next section.

6.4 Conclusions

In Phase 1, the regional planning reserve requirement, given a demand forecast and schedule of plant retirements, determines the need for new resource builds. Planning reserves include all generation technologies in the calculation but reduce the capacities of wind and solar to reflect their limited availability during peak demands. Some scenarios (the CO_2+ scenario especially) included large amounts of wind, which contributed only a small fraction toward meeting the planning reserve requirement. Because generation from these sources was often much larger than the reduced amount included in the reserves requirement, there was extra generation for export to other regions if transmission was available but curtailments were necessary (as noted in Phase 2) if not. This is discussed further in Chapter 3.

The Phase 2 calculations used operating reserves in their calculations. The required reserve quantities varied greatly by region, with PJM having the greatest requirements, both in megawatts and as a percentage of demand. In the modeling, only thermal fossil plants (coal, gas steam, and CC) and hydroelectric plants could provide reserves; these plants had to be running at least at their minimum dispatch points and could only provide limited quantities based on their ramp rates. While many regions had sufficient hydro to cover most of their reserves requirement, other regions were forced by their reserves requirements to increase output from the committed thermal units while other lower cost units (most notably wind) were curtailed. A sensitivity was run that reduced the reserves requirement by 50% (to represent DR supply of reserves in some of the regions) and enhanced CC flexibility (minimum power levels, minimum up/down times, and ramp rates). This led to a reduction in the amount of low cost power curtailed, more fully discussed in Chapter 3. During peak times, some regions had to back down their more efficient CC plants to provide reserves and call on more expensive CT units and DR to provide energy, as discussed in Chapter 4.

7. TOPIC 7: WIND CURTAILMENT

7.1 Background of Topic

Wind power is a resource that can provide large amounts of electrical power at very low marginal cost. The variable operating cost is near zero, and with production tax credits (PTCs) the final cost to producers is actually negative. Generally, it is most economic for the sector to take all generation provided from wind. However, there are various reasons why at times the system cannot accept all the wind power available and some wind farms have to reduce power levels. There can be multiple contributing factors to curtailment: there is simply more production than consumers demand at the time; there is insufficient transmission to carry the power to other regions where there is demand; and/or there are other factors such as local reserve requirements, transmission impedance, ramping limitations, environmental regulations, or other low cost resources available. These factors become more of an issue as the fraction of power from wind increases.

In Phase 1 of the EIPC study, there was a brief question about whether any curtailment would occur. An analysis showed that even in the CO_2+ scenario, the level of curtailment was less than 2% in all of the regions. However, in Phase 2 there was a significant amount of wind curtailment in the CO_2+ scenario from the GE MAPS runs, along with some in the RP/R scenario as well. CRA released data that showed the amount curtailed over the course of the year for each region (Table 38).

Table 38. Phase 2 Wind Curtailment Amounts and Percent of Potential Generation

	BAU		RPS/R		CO_2+	
	GWh	% Potential	GWh	% Potential	GWh	% Potential
ENT	0	0%	0	0%	237	30%
MAPP US	1	0%	393	2%	3,894	12%
MISO IN	0	0%	0	0%	521	2%
MISO MI	1	0%	1	0%	35	0%
MISO MO-IL	1	0%	1	0%	8,426	26%
MISO W	123	0%	4,553	5%	65,463	25%
MISO WUMS	0	0%	0	0%	52	1%
NE	0	0%	119	1%	22,417	40%
NEISO	49	0%	2	0%	439	2%
NYISO A-F	11	0%	3	0%	985	5%
PJM E	0	0%	14	0%	47	1%
PJM ROM	3	0%	3	0%	2	0%
PJM ROR	5	0%	444	0%	504	1%
SPP N	1	0%	1,053	3%	21,271	15%
SPP S	1	0%	3,713	4%	4,910	3%
TVA	0	0%	1	0%	-	0%
VACAR	4	0%	19,162	24%	11	0%
IESO	865	5%	528	3%	2,192	13%
MAPP CA	0	0%	25	2%	5	0%
EI	1,066	0%	30,015	5%	131,412	15%

The CO_2+ scenario had the most widespread curtailments and so was the subject of the most scrutiny. The western plains regions had the largest amount of curtailment, although there were pockets of curtailments in other regions as well. In the RPS/R scenario, the largest curtailments occurred in VACAR. These were likely offshore wind curtailments and possibly due to inadequate transmission build-out.

7.2 Estimation of Hourly Wind Schedule and Curtailments

To explore the various reasons for the curtailments it was necessary to determine when the curtailments happened and what the demands and production requirements were across the EI. The Phase 2 reports included hourly output for all types of generation, including wind, for each NEEM region. The reports also included the amount of wind energy curtailed for the year by NEEM region (Table 38). Neither wind curtailments nor wind energy available (also referred to here as potential wind generation) were provided on an hourly basis. Thus, we had to estimate the amount of wind energy available in each hour based on the data available. We created a heuristic and applied it to five specific regions that had high levels of curtailment (MISO MO-IL, MISO W, NE, SPP N, and SPP S). These regions are highlighted in Table 38. MISO MO-IL, MISO W, NE, and SPP N all experienced high levels of wind curtailments in the CO_2+ scenario. SPP S experienced high levels of wind curtailments in the RPS/R scenario. While VACAR also experienced high levels of wind curtailments in RPS/R, an estimated hourly wind availability schedule could not be produced for that region due to inconsistencies in the reported data for wind output and capacity. A comparison of the estimated wind availability to the wind output from the model provided an estimate of hourly curtailments.

Hourly wind availability was estimated using the hourly wind generation information from the CO_2+ and RPS/R scenarios and their sensitivities. Because the CO_2+ and RPS/R scenarios and the CO_2+ sensitivity that had reduced wind capacity have different amounts of wind capacity installed, the hourly wind generation was normalized based on the amount of capacity for each scenario or sensitivity. Thus, the hourly wind generation data were converted from a megawatt basis to a fraction of wind capacity basis. This placed the various scenarios and sensitivities on an equal footing for a direct comparison. The estimated wind availability for a particular hour was determined by taking the maximum of the normalized wind generation levels across the scenarios/sensitivities for that hour. This operation was performed for all hours of the year to find the estimated wind availability schedule.

The estimated hourly wind availability schedule was then converted back to a megawatt basis for the various scenarios and sensitivities. The hourly curtailments were then estimated by subtracting the hourly wind generation from the hourly wind availability.

The estimation method does not capture all of the curtailments but does significantly reduce the amount of unaccounted for energy for all of the regions except MISO MO-IL. (MISO MO-IL experienced significant local congestion in the production costing model that likely caused curtailments across all the sensitivities.) While the estimation method does not exactly recreate the hourly wind availability, it is sufficient to identify specific hours of the year with large curtailment levels. The transmission interchange levels and generation levels of other generation sources can then be examined for these hours to provide insight into the causes of the wind curtailments.

7.3 Timing of Curtailments

A first analysis compares the potential wind generation, wind curtailments, and wind generation by hour of day (Fig. 67). These curves show the average values for all 365 days of the year. Curtailments were highest in the early morning hours, peaking around 5:00 a.m. Because demands are lowest at these times, there is clearly a connection between level of curtailments and demand. While it is also true that potential wind generation is also highest before noon, a clear suppression of demand in the early hours can be seen for most regions examined. SPP-S has a relatively flat and low level of curtailment, so its actual generation stays about the same shape as the potential generation.

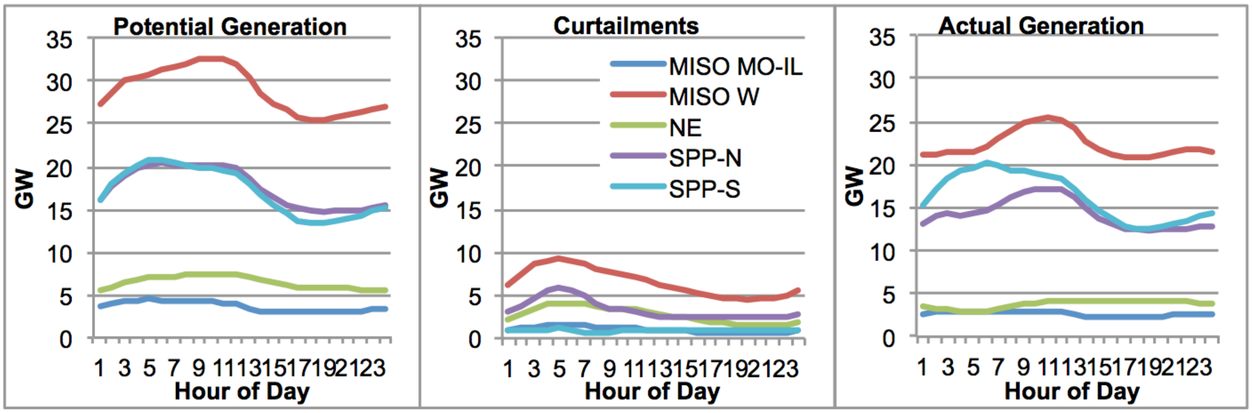


Fig. 67. Potential wind generation, curtailments, and actual generation in the CO_2+ scenario by hour of day.

7.4 Exploration of Peak Curtailment Day

Another avenue of exploration is to examine the transmission flows during an hour of high curtailment to see whether regional transfer capacities are being strained. As an example, April 1 had the highest level of curtailment for the year for those regions in which we calculated hourly curtailments (Fig. 68). There was major curtailment in the early hours and supply was only slightly above the region's demands, so little was exported.

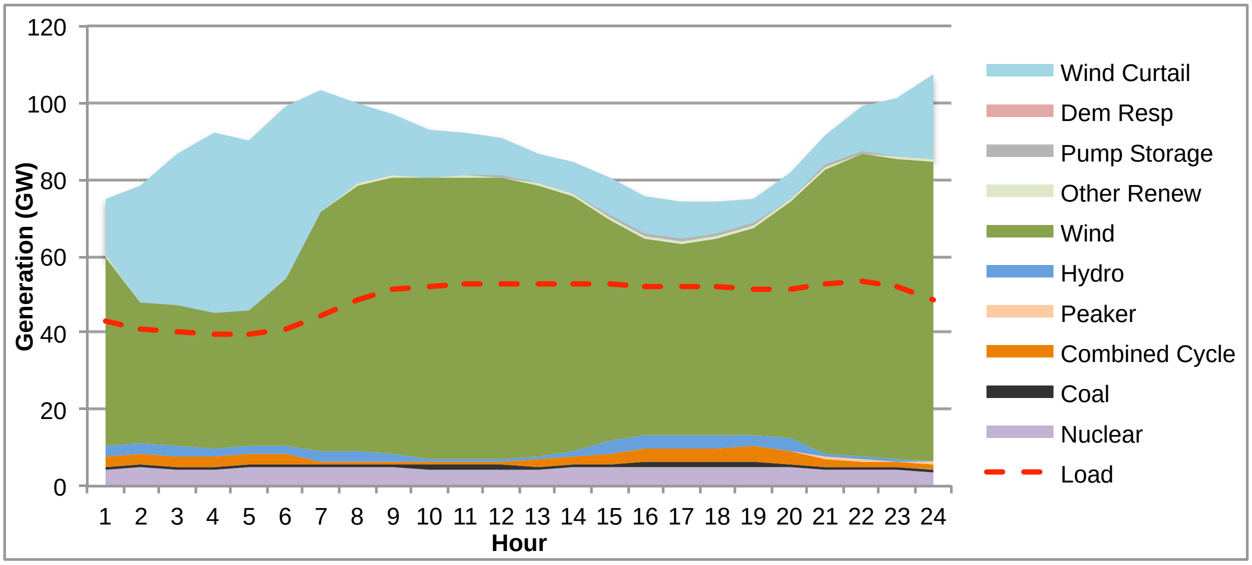


Fig. 68. Supply and demand for major curtailed regions on April 1 in the CO_2+ scenario.

The lack of export is verified by looking at the tie-line flows at 4:00 a.m. for the scenario (Fig. 69). Even the HVDC lines from SPP N and MISO W to PJM were only lightly loaded. (In the detailed reports, one of the four HVDC lines between MISO W and PJM ROR was actually flowing back into MISO W.) PJM and other regions were not able to absorb the extra wind power in this hour.

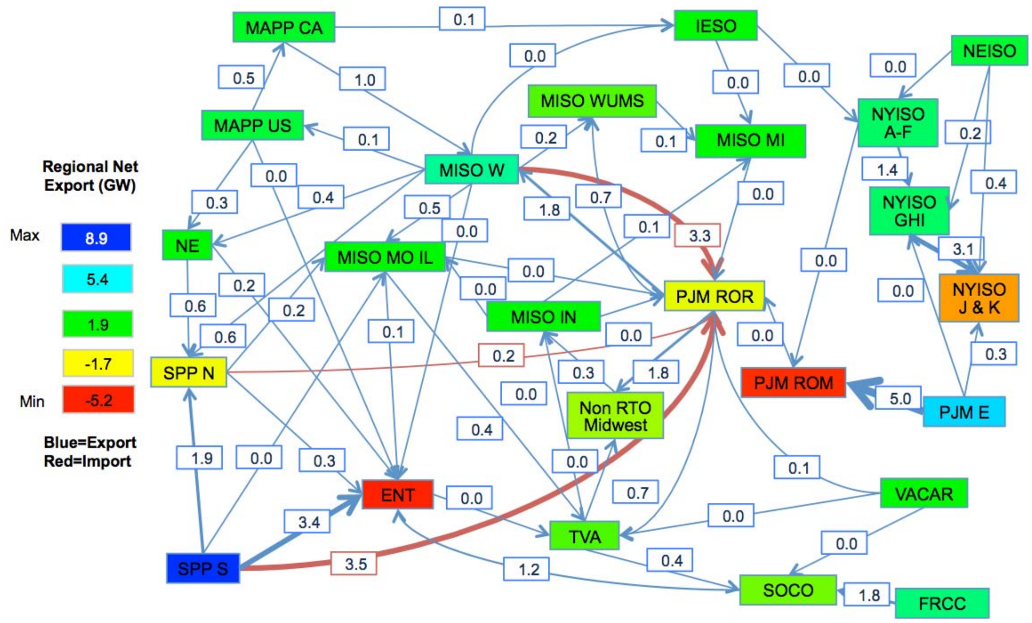


Fig. 69. Tie-line flows on April 1 at 4:00 a.m. for the CO_2+ scenario.

The PJM region could not take additional power because its plants were running at the minimum levels or had to be running to be available in later hours. In Fig. 70, the generation levels by technology are shown for the three PJM regions combined. Note that the CC plants are running at 17,300 MW constantly through the morning. If these were all 750 MW plants running at their minimum of 50% of capacity, then there would be 50 plants running, and they would provide 5,000 MW of reserves. Based on the equation for required reserves, PJM needs 6,200 MW of reserves in that hour. Subtracting 1,400 MW supplied by hydro leaves 4,800 MW of reserves needed, about the same amount as provided by the CCs. So for this hour, it appears that the main cause of the curtailed wind was the reserves requirements and other operating constraints, not lack of transmission.

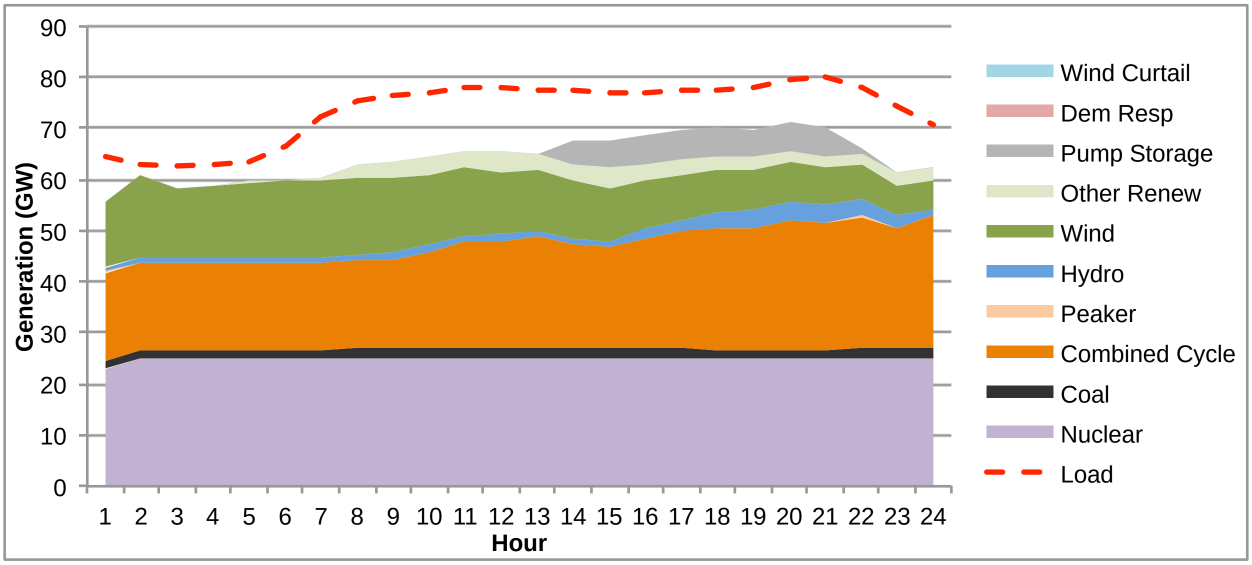


Fig. 70. Generation and loads for PJM regions on April 1 in the CO_2+ scenario.

A further bit of information about the state of the grid at any point in time is the LMPs for the different BAs. CRA reports the hourly prices for 154 different BAs across the EI. These have been mapped to the general location of the areas, although some BAs cover overlapping regions and have their headquarters near each other. Plotting the points and color-coding based on the price shows the span of prices across the EI for the April 1 case (Fig. 71). Most areas have prices at or below \$10/MWh, with some areas even below zero. As all coal and CC plants have variable costs higher than this price, they must be operating at a loss on energy sales and operating because either they are needed for operating reserves or because they will be needed later in the day. (The location in North Dakota with a high spot price appears to be the result of a localized transmission issue resulting in a load pocket.) Sure enough, by 10 a.m. prices have risen across most of the EI to around \$60/MWh.

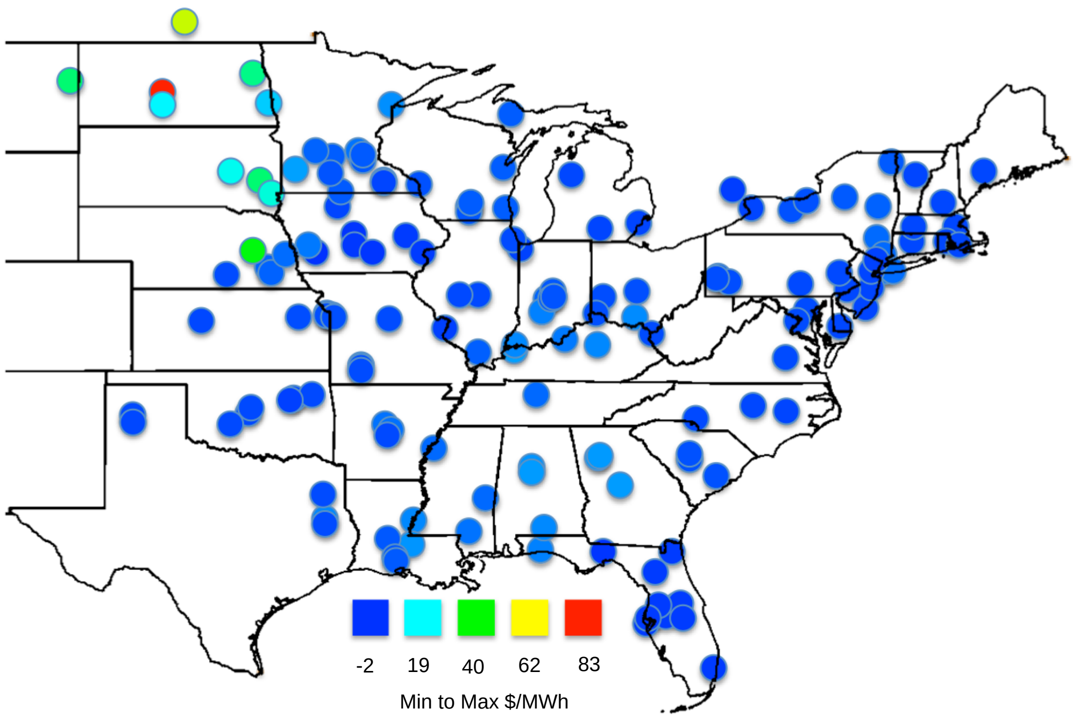


Fig. 71. Locational marginal prices for balancing areas across the EI on April 1 at 4:00 a.m. for the CO_2+ scenario.

7.5 Effect of Reduced Spin Requirements and Flexible Combined Cycle

Another means to examine the question is to evaluate the results from the Hi Spin sensitivity. As mentioned previously, spin requirements were lowered for several regions, while ramp rates (and consequent reserves supply) were increased for several technologies, and the minimum up and down times for these technologies were also reduced. These changes all combined to significantly reduce the curtailments in many of the hours of study. Production levels on April 1 are significantly different for both the curtailed regions and PJM, as shown in Fig. 72 and Fig. 73. Comparing these to Fig. 68 and Fig. 70 reveals a much lower level of curtailment in the curtailed regions and a greatly reduced level of CC production in PJM in the early hours of the day. Clearly the spin requirements and/or minimum up/down times in the base case played a role in the level of curtailments. This is further revealed in the tie-line flows for 4 a.m. across the EI (Fig. 74). The HVDC lines become almost fully loaded and large amounts of power are transferred from MISO W, NE, and SPP N through SPP S to ENT, TVA, and SOCO (as compared to the CO_2+ case in Fig. 69.)

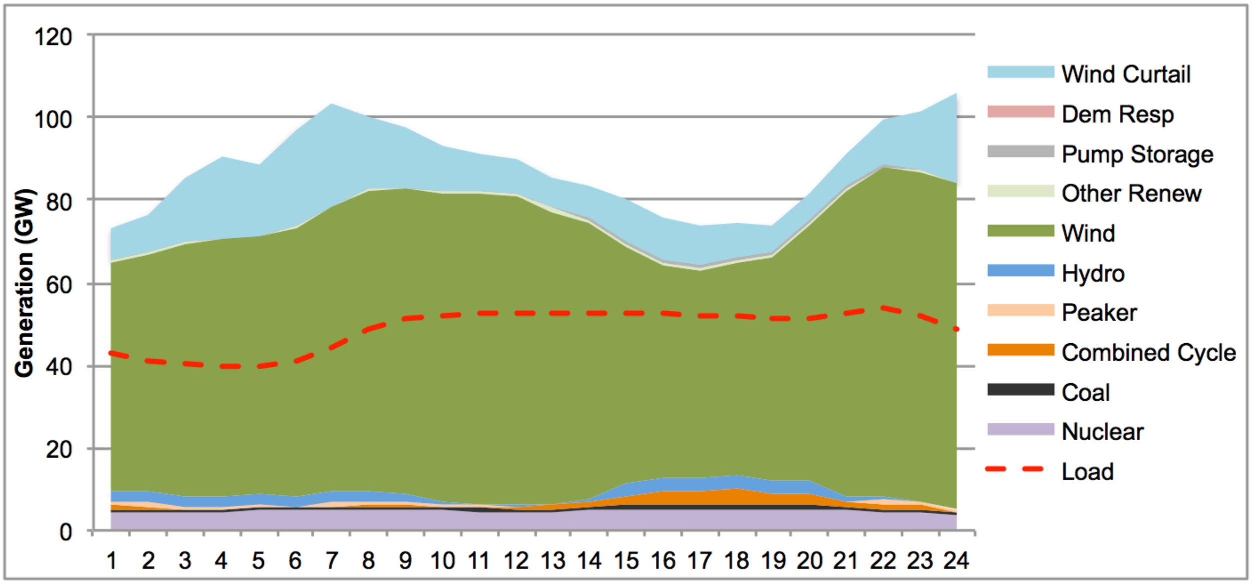


Fig. 72. Generation on April 1 in the curtailed regions in the Hi Spin sensitivity.

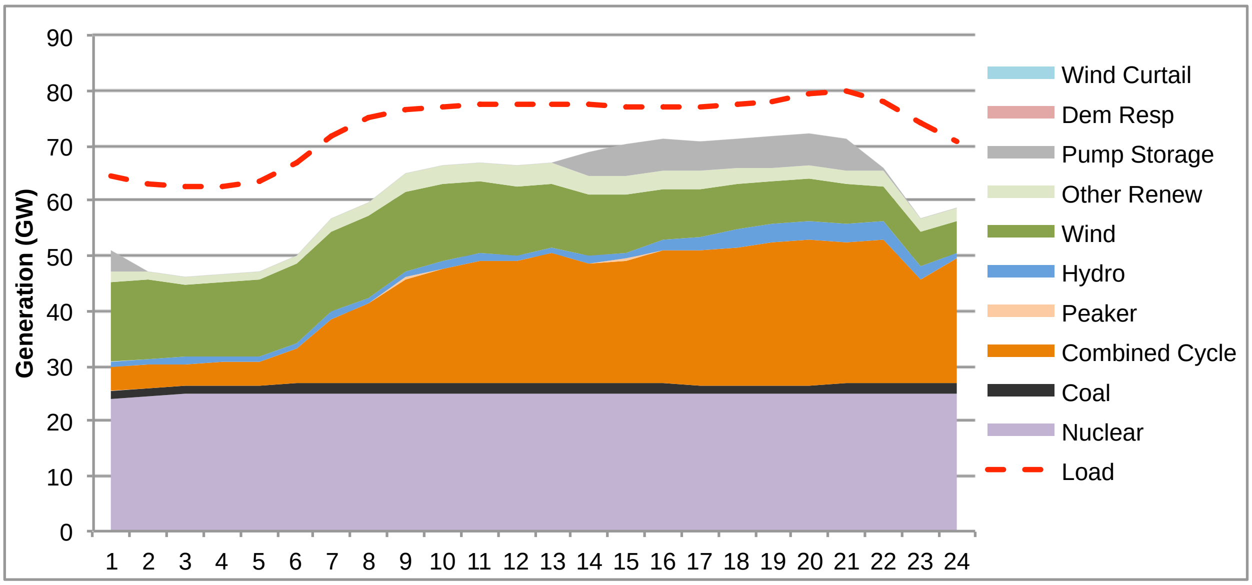


Fig. 73. Generation on April 1 in PJM in the Hi Spin sensitivity.

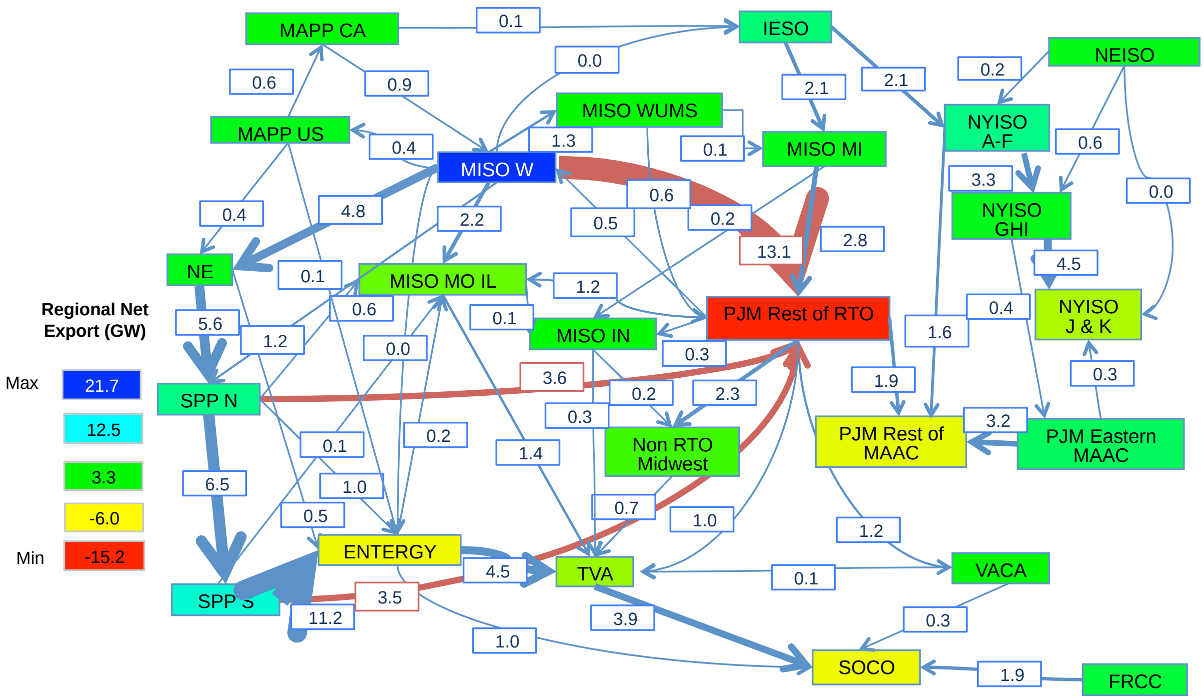


Fig. 74. Tie-line flows on April 1 at 4:00 a.m. in the Hi Spin sensitivity.

While spinning reserve requirements and generating plant parameters had some effect on the amount of curtailment, relaxing those requirements still left most of the curtailments. The total curtailments dropped just 9% from 131 TWh in CO_2+ to 120 TWh in the Hi Spin sensitivity. MISO W curtailments for the whole year dropped just 5%, from 65 TWh to 62 TWh. Spinning reserve requirements do not seem to account for all wind curtailments. We next examined tie-line loading to determine whether those constraints may have resulted in additional curtailment.

7.6 Curtailments Versus Tie-Line Capacity

It is possible that wind is curtailed because there is not enough transmission capacity to transport it to where it is needed. If the curtailments occurred due to tie-lines being fully loaded, then most curtailment should occur during high tie-line activity. We summed the hourly net tie-line flows out of the five curtailed regions for which we calculated the curtailments by hour. We then compared that to the amount of curtailment in these five regions combined. In the CO_2+ scenario there is a general peak tie-line flow out of the curtailed regions of around 40 GW (Fig. 75). The highest curtailments typically occurred when the tie-lines were at this power level, which indicates that curtailments could probably have been reduced with increasing tie-line capacity.

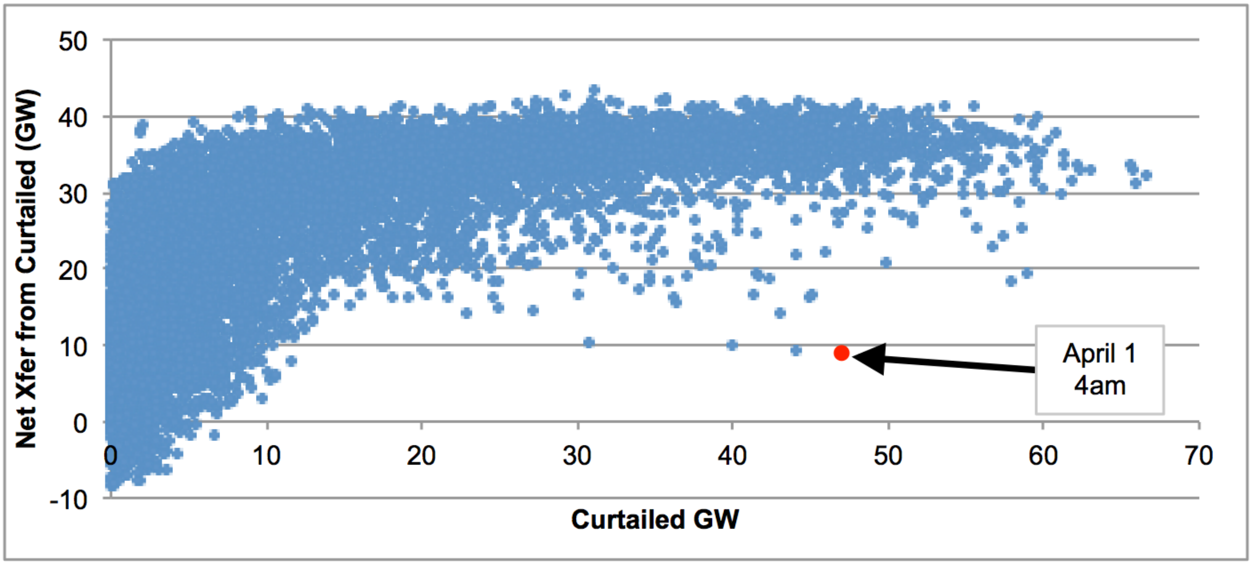


Fig. 75. Net transfer vs. curtailment in the curtailed regions for the CO_2+ scenario.

This is even more apparent when comparing the Hi-Spin sensitivity (Fig. 76). Many of the points with high curtailments but low tie-line flows either increase their flow, reduce their curtailment, or both. Examples include the April 1 4:00 a.m. example, with curtailments and transfers for the two cases shown in Table 39. In those hours affected by the changes in reserve requirements and plant capabilities, the tie-lines were more heavily used and the curtailment amounts went down because the power was used in the other regions.

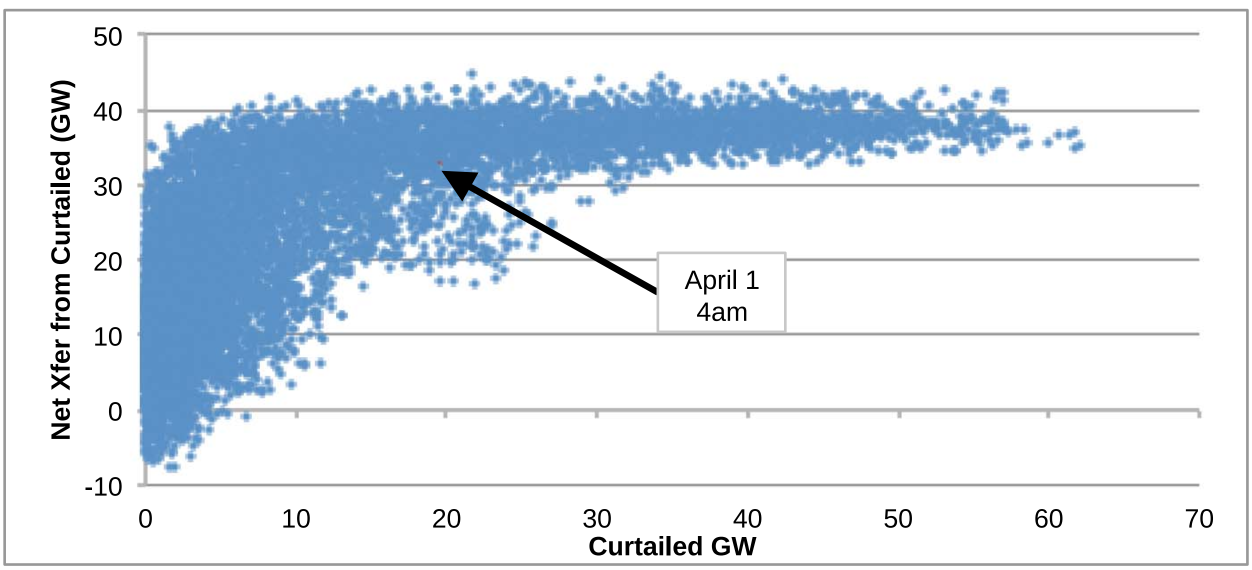


Fig. 76. Net transfer vs. curtailment in the curtailed regions for the Hi Spin sensitivity.

Table 39. Curtailments and Net Transfers
April 1 at 4:00 a.m. for curtailed regions

	Curtailments	Transfers
CO_2+ Scenario	47.0 GW	8.9 GW
Hi Spin Scenario	19.7 GW	33.2 GW

More than half the hours have curtailments below 10 GW in the five regions studied and over 70% of the time curtailments are below 20 GW. Figure 77 is a histogram showing the fraction of the year for different ranges of curtailment levels. There is a slight difference between the CO_2+ scenario and the HI Spin sensitivity, reflecting the shift to lower curtailment amounts with the Hi Spin changes in reserves requirements and plant capabilities.

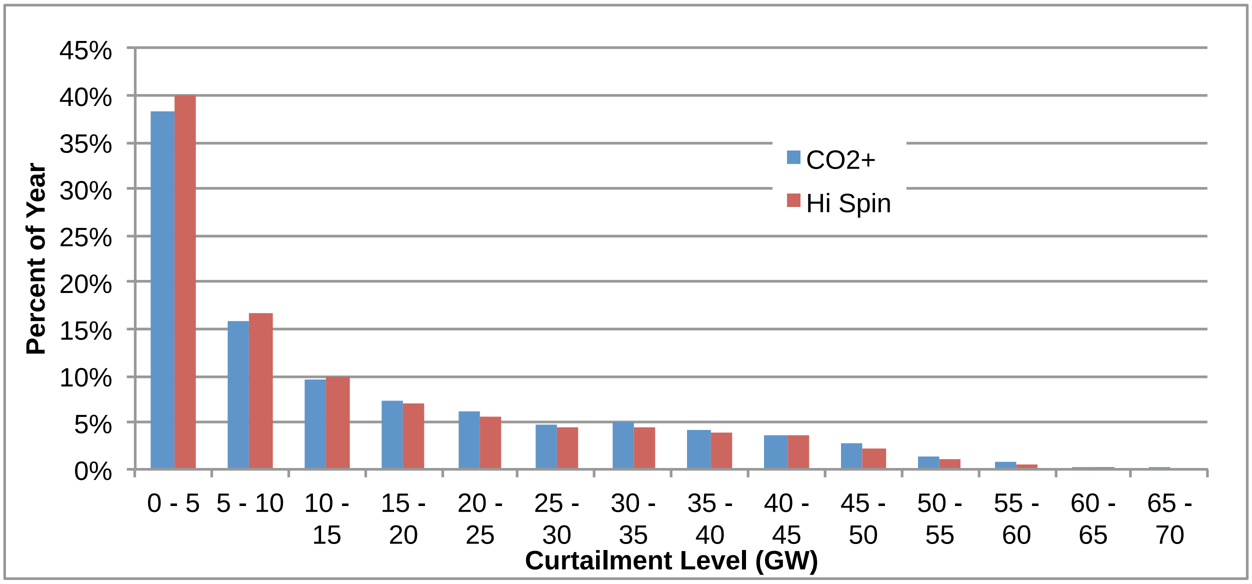


Fig. 77. Percent of year that curtailments in curtailed regions were at different levels.

The amount of curtailments that could be resolved through tie-line improvements is unknown. The CO_2+ scenario included 21 GW of additional HVDC lines (plus a large amount of conventional transmission). As there were still some hours with more than 60 GW of curtailment, adding 4 times as much HVDC capacity as in that scenario might eliminate most but still not all curtailments. Also, their construction would be quite difficult and placement would likely require significant upgrades in supporting infrastructure. The economic rationale for expansion of the grid, which must balance a large number of factors, is thus more complicated than just meeting reliability criteria during peak times (the method used in the EIPC study) or eliminating all wind curtailments.

An examination of the hourly curtailments in the Hi Spin sensitivity reveals that the periods with high levels of curtailments also have high levels of tie-line transfers out of the curtailed regions. Figure 78 shows the curtailments in the curtailed region (MISO W, MISO MO-IL, SPP N, SPP S, and NE) and the net transfer from the curtailed regions to other areas for each hour, the same as Fig. 76. The vertical red line represents the median hourly wind curtailment (7,712 MW). Thus, half of the hourly curtailments lie to the left of the line (lower than the median) and the other half lie to the right of the line (greater than the median). The horizontal red line represents the median hourly net transfer (27,174 MW) from the curtailed region. These lines divide the graph into four quadrants, described in Table 40.

If the two sets of data are independent, roughly the same number of points will lie in each quadrant. If quadrants I and III are overrepresented, the sets of data tend to be correlated. In this case, there are 3,690 h in each of quadrants I and III and 690 h in each of II and IV. This means that 42% of the time both transfers and curtailments are higher than the median, 42% of the time they are both lower than the median, and 8% for each of the other two possibilities. In general, this indicates that high levels of wind curtailments occur when net transfers are high and low levels of curtailments happen when net transfers are low.

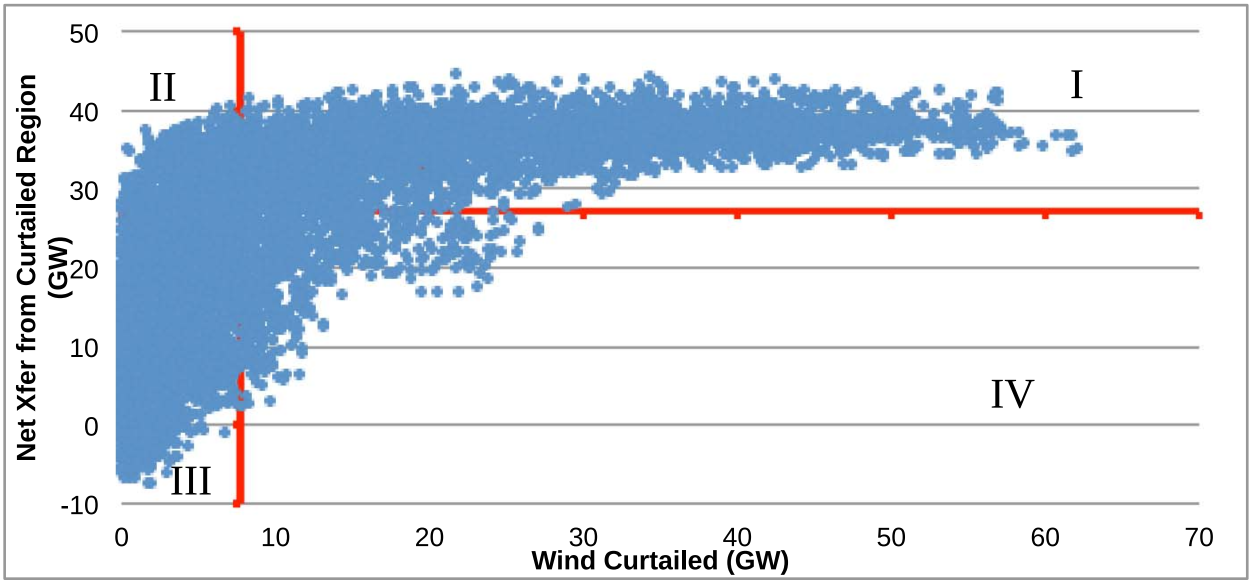


Fig. 78. Net transfer vs. wind curtailment in the curtailed regions in the Hi Spin sensitivity.

Table 40. Curtailment and Transfer Quadrants for the Hi Spin Sensitivity

Region	Transfers	Curtailments	Hours	Curtail TWh
I	> Median	> Median	3,690	96.5
II	> Median	< Median	690	3.1
III	< Median	< Median	3,690	9.4
IV	< Median	> Median	690	8.5

Looking further out toward the extremes, there are 1,390 hours where curtailments exceed 30 GW. Of those, only two occur in hours with less than 30 GW of transfers, and neither of those occurs when transfers are lower than the median. Thus, once we account for the hours where large amounts of curtailments result from spinning reserve requirements by adjusting the spinning reserve requirements and generator characteristics in the Hi Spin sensitivity, the high curtailments occur during hours with high transfers. This indicates that transfer limitations are a major factor.

A final point is that the vast majority of curtailed energy occurs in Quadrant I (last column in Table 40), when both curtailments and transfers are above the median. More than 96 TWh of curtailment from these five regions occurred in Quadrant I in the Hi Spin sensitivity. In the CO_2+ scenario, Quadrant I contained more than 101 TWh. The Hi Spin sensitivity only reduced curtailment by 9 TWh overall, so compared to spinning reserve requirements, the dominant reason for the curtailments was the transfer limitations.

7.7 MISO MO-IL Supply Pocket

There still remain a number of hours in the Hi Spin sensitivity when net transfers are well below the peak amount but curtailments arise. These can occur when there are local pockets of congestion within a region. Wind power is available but blocked behind a bus with inadequate capacity, even though there is capacity available on one of the outbound tie-lines. This occurred in the MISO MO-IL region (as well as the VACAR and MAPP US regions) a significant percent of the time.

Figure 79 is a map of the locational marginal prices at the different BAs on April 1 at 10:00 a.m. in the CO_2+ scenario. The price in the Ameren Corporation control area, located in southwestern Illinois, is

$125/MWh (the highest in the EI), while in the neighboring Columbia Water and Light area (Columbia, Missouri), the price is only $1/MWh (the lowest in the EI) in that hour.

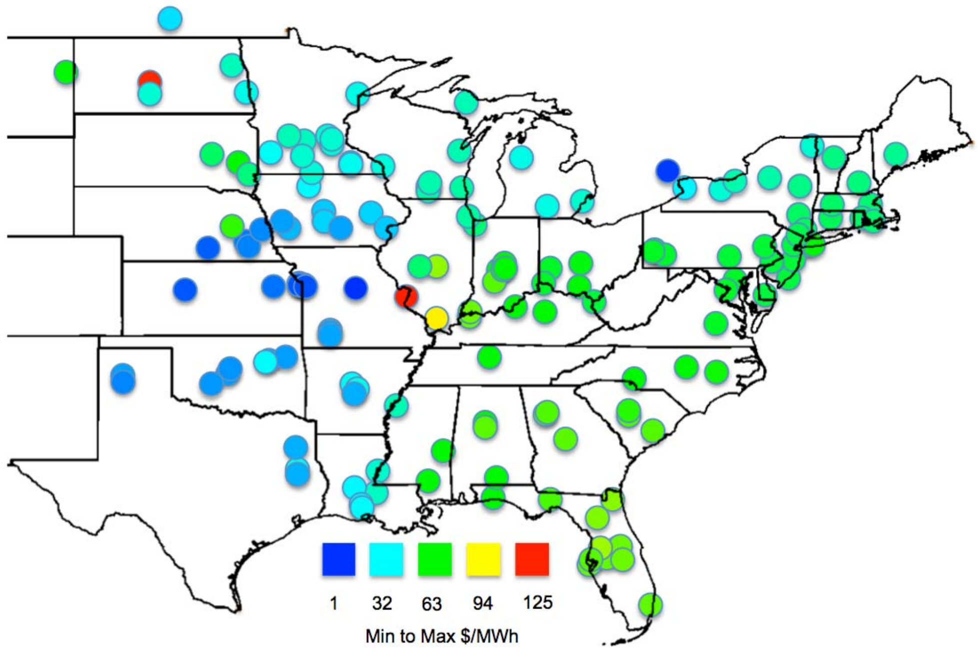


Fig. 79. Locational marginal prices on April 1 at 10:00 a.m. in the CO_2+ scenario.

Wind was curtailed in MISO MO-IL throughout the morning in this scenario, even though MISO MO-IL had to import significant amounts of power after 7:00 a.m. (Fig. 80). Meanwhile, some "peaker" capacity had to be run, especially in the late evening. This indicates that some regions within MISO MO-IL could not access the available power in other parts of the region.

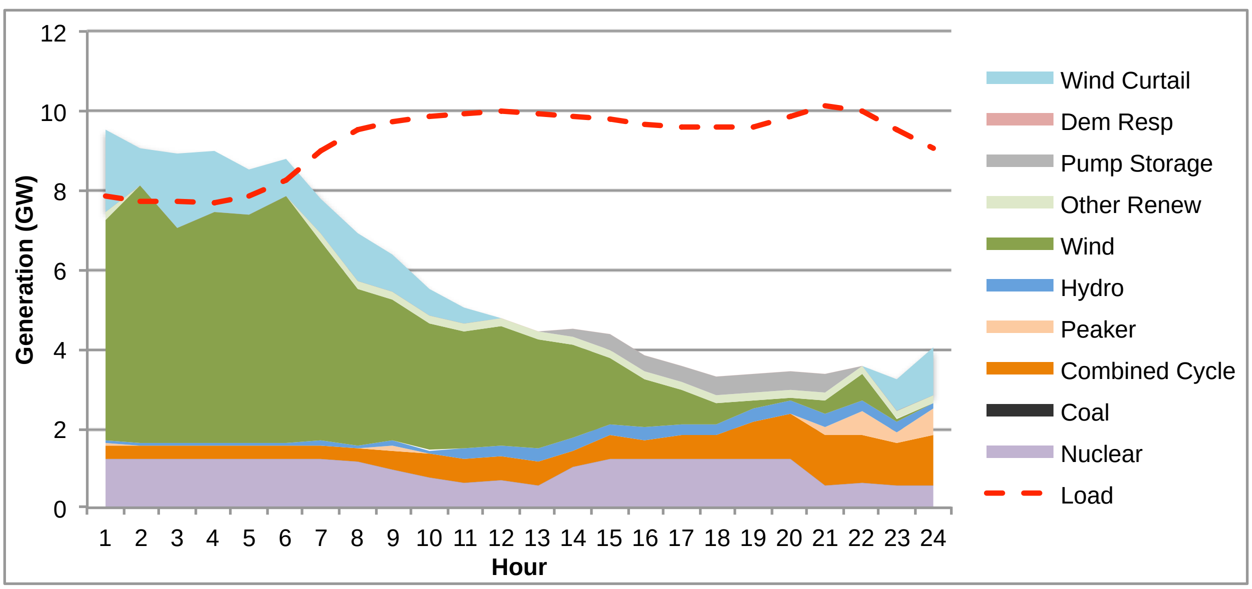


Fig. 80. MISO MO-IL generation and load on April 1 in the CO_2+ scenario.

Discussions with EIPC and examination of the transmission build-out revealed that a significant wind farm (4,000 MW) had been added to the grid in northeast Missouri. Shadow prices between flowgates from GE MAPS show a frequent difference in price between certain buses west of St. Louis. Likely, this bus or tie-line should have been upgraded to open up the curtailed wind to the Ameren control area but was not caught during the first part of Phase 2. It would require further analysis in the PSS/E model to determine appropriate changes and possible consequent changes to other infrastructure.

7.8 Conclusions

The high levels of wind curtailments in Phase 2 occurred because the GE MAPS model was unable to use all of the available wind during a number of hours of the year. The factors driving this inability differed depending on the hour and region being examined. During certain hours, such as the morning of April 1, operating reserve requirements outside of the curtailed region limited the ability to export power even though tie-line capacity was not being fully used. During other periods, tie-line capacity was not sufficient to move the available power to other regions. Finally, local transmission congestion such as within the MISO MO-IL region created a generation pocket from which wind generation could not get out to the rest of the system.

8. TOPIC 8: DEMAND RESPONSE

8.1 Demand Response in Phase 1

DR is a complex collection of programs and technologies that let demand respond to supply, mainly through reduction of demand in the face of supply shortages. The Federal Energy Regulatory Commission (FERC) defines DR as "the changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (FERC 2009). Different DR programs can be automated or not, controlled by the utility or customer, involve direct price incentives or appeals, and apply to different demand sectors. Several studies on DR in the EI were commissioned during the EIPC process.[*] The following are two notable ones.

- Baek, Young Sun, et al. *Eastern Interconnection Demand Response Potential.* ORNL/TM-2012/303. Oak Ridge, TN: Oak Ridge National Laboratory, November 2012.

- Navigant, *Assessment of Demand-Side Resources within the Eastern Interconnection*, prepared for the Eastern Interconnection States' Planning Council, March 2013.

In June 2009, FERC released a study on DR, *A National Assessment of Demand Response Potential,* or NADR (FERC 2009). For the EIPC study, the amount of DR for each region was calculated using the state-by-state projections of DR from the FERC NADR model. The model projects both future DR and future peak demand through 2019 for four different scenarios: BAU, expanded BAU, achievable amounts, and full participation. The state-weighted average ratio of DR to peak demand was found for each NEEM region in the study.

For most of the futures in Phase 1, the SSC decided that the percentage of demand that DR could supply would transition from the percentages of demand in the FERC BAU scenario in 2015 to that of the FERC Expanded BAU by 2025 and then continue with those percentages to the end of the period. For the aggressive DR Future 4, the SSC transitioned from the BAU percentages in 2015 to the full participation percentages by 2025 and then continued those percentages to the end. Some utilities treat DR as an alternative supply (where 1 MW of DR equals 1 MW of supply) and some as a reduction in demand (where 1 MW of DR reduces demand by 1 MW, and so for calculation of the reserve requirement the DR is equal to its capacity times 1 plus the reserve margin). To approximate the variations between regions, the SSC multiplied the DR capacity by one plus half of the required reserve margin for each region.

The calculations fixed the amount of DR capacity that would be added within each region rather than allowing NEEM to select how much DR capacity to build. However, the model could choose to call upon, or dispatch, this power. Within NEEM, CRA modeled DR as a forced-in pseudo-generator with no fixed cost but a high energy cost (and consequent price for dispatch decisions) so that it would only be used when most or all other supplies were deployed. In Phase I of the modeling, the original amount of potential DR from NADR was calculated based on NADR's default ratio of critical peak price (CPP) to average price of 8. With the default ratio of CPP to average price and a rough estimate of average retail electricity price, the average price of dispatching DR was set at $750/MWh. This estimated DR price was applied to all DR supplies in the dispatch process of NEEM. However, in Phase 1 very little DR was dispatched, just 39 GWh in the VACAR and 24 GWh in the FRCC in the CO_2+ scenario and none in the

[*] A similar study (Satchwell et al., 2013) was conducted for the Western Interconnection.

other regions or scenarios. Even so, DR served to reduce the capacity requirements from other resources for all regions because it could be applied in the reserve margin calculations.

8.2 Demand Response Supply Curve for Phase 2

The modeling in Phase 2 allowed a more detailed approach but still treated DR as pseudo-generators within each region. Instead of a single price, there could be up to six supply amounts, each at a different price point. Still, as with NEEM, the GE MAPS model did not limit DR to a maximum number of hours per year or total amount of generation over the year, so the modeling had to use price as a lever to get DR to be dispatched semi-realistically. A more realistic DR supply curve was needed than the single tier at $750/MWh. Therefore, a tiered pricing arrangement or supply curve for DR was calculated, with six different DR price tiers, but still with an average price for DR of $ 750/MWh to match the Phase 1 assumption.

ORNL researchers who conducted the DR study created a national stepwise DR supply curve for 2030 based on the ORNL version of the FERC NADR model (ORNL NADR). Under the full deployment scenario of the ORNL NADR, 30 different cases with a variation of CPP ranging from $50/MWh to $1,500/MWh were run to see how system peak load would respond to changes in CPP (Fig. 81).

Figure 82 shows three supply curves for comparison: a supply curve for pricing-related full DR deployment, the five-tier step function of the same supply curve, and the supply curve used in NEEM for Phase 1. The NEEM curve from Phase 1 was driven based on the FERC 2009 NADR results and shows the maximum DR available in 2030 would be 209 GW.

Actual DR would have a mixture of programs that dispatchers could call upon. Some programs have no specific price but have time or frequency limits. Some allow customers to vary their response at different price points. In addition, the variation in CPP addresses only the impact from pricing programs (Fig. 81 and Fig. 82). To reflect such DR supply from nonpricing programs, ORNL researchers chose to allocate the nonpricing DR amount into each tier proportionally (Fig. 83). Seventy percent of the peak load reductions (PLR) that came from nonpricing DR was distributed into the first five price tiers, and the remaining 30% of PLR was allocated to a new sixth price tier. The price for this last tier was set so that the weighted average of DR price stayed at $750/MWh to maintain consistency with Phase 1.

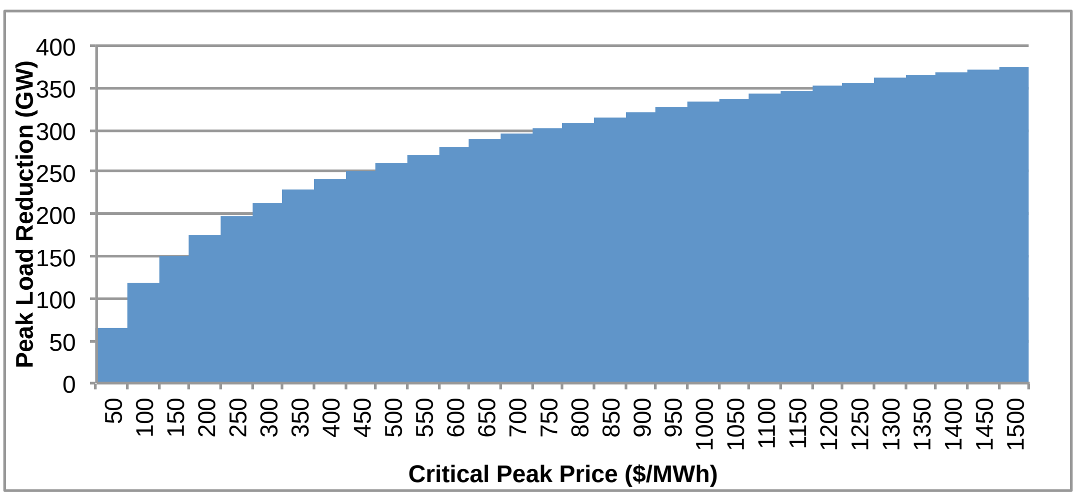


Fig. 81. ORNL NADR runs with variation in critical peak price.

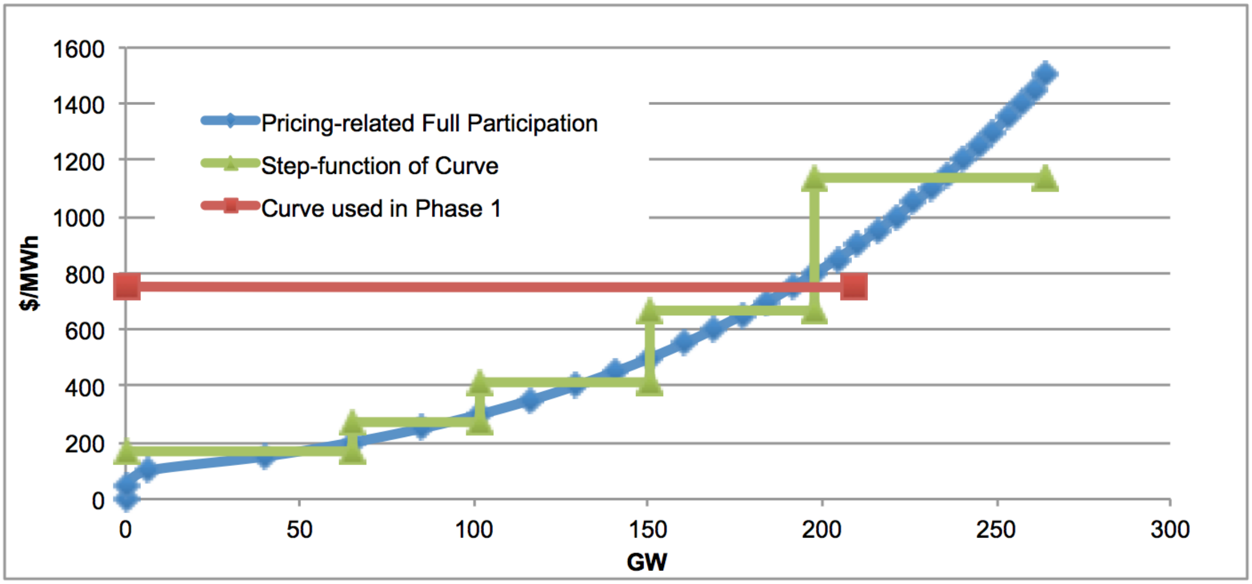


Fig. 82. Supply curve for pricing-related DR programs in 2030. Five-tier approximation and Phase 1 single tier curve also shown.

The lowest tier size was picked so that its average price would be in the neighborhood of the cost of a CT. The lowest cost tier of 22% of maximum DR available in any region could be supplied at the first price tier of $165/MWh, roughly between the efficient and inefficient CT costs, as shown in Fig. 83. This amount of DR could possibly replace CTs in the dispatch process. The last price tier represents exceptionally expensive DR options such as rotational blackouts that involve high societal costs but are not included in the typical DR program categories.

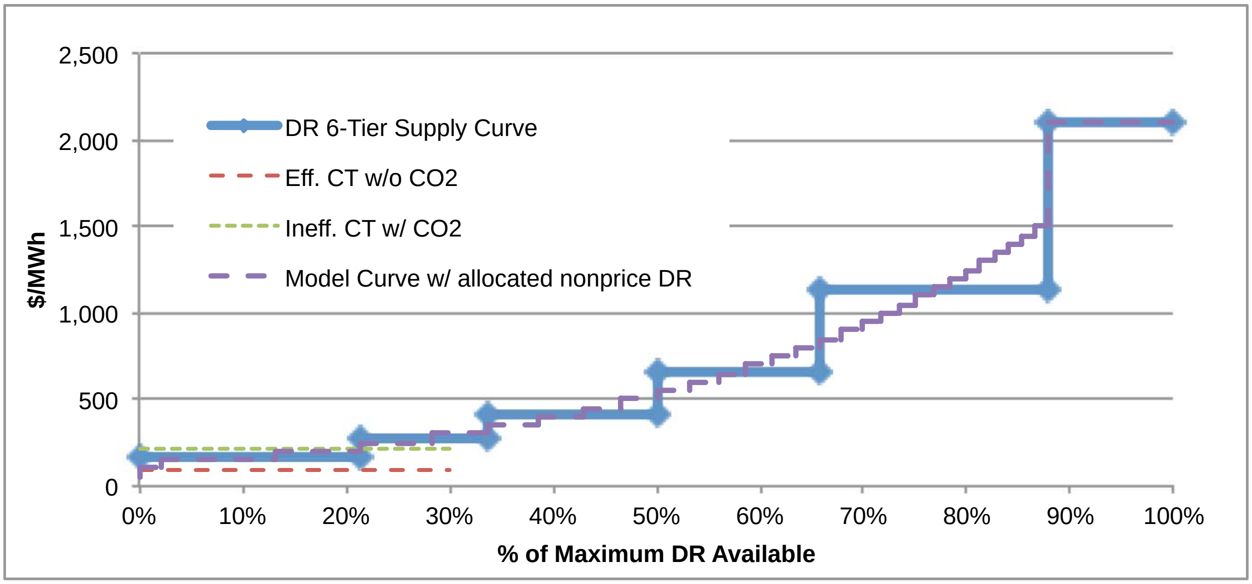


Fig. 83. Six-tier supply curve and model curve with allocated nonprice demand response (DR) in 2030 for Phase 2.

The resulting six tiers with both their price and the fraction of total DR within each region, as used in the EIPC Phase 2 study, are shown in Table 41. Each region's total DR potential for the scenario in question was multiplied by the fractions from the table and priced at the amount shown. This simplified the supply curve for modeling each region's DR amounts for the purpose of the analysis.

Table 41. Demand Response Supply Curve as a Proportion of Total Demand Response Available in Regions for EIPC Study

Tier	Price $/MWh	Percent of Total Capacity	
		Incremental	Cumulative
1	165	22	22
2	273	12	34
3	418	16	50
4	665	16	66
5	1,142	22	88
6	2,100	12	100

8.3 Demand Response Dispatched in Phase 2

As shown in Fig. 64, many of the regions rely on DR to supply some amount of capacity to meet 100% of their peak demand. This is also shown for the CO_2+ scenario in Fig. 84 for all of the NEEM regions individually. The wind and solar capacities are split between the fraction that counts toward the reserve margin and the uncredited capacities that do not contribute to the reserve margin. The red lines show the peak demand for the year in specific regions for the CO_2+ scenario. DR equals a significant fraction of the supply as shown in Table 42 (between 20% and 30% in most regions).

In the BAU and RPS/R scenarios, DR generation is concentrated in the three most southeastern regions (Table 42). Overall DR capacity and generation was highest in the CO_2+ scenario. All regions had at least some small amount of DR use. The most significant use is in two regions with wind power (MISO MO-IL, and MAPP US) where, based on BA prices, there appeared to be some internal load pockets or generation constraints as described in the previous section. The other major area was the Southeast, with FRCC, SOCO, and especially VACAR showing high levels of DR use. These regions do not have easy access to significant amounts of wind power and so must rely on DR to provide power during peaking periods.

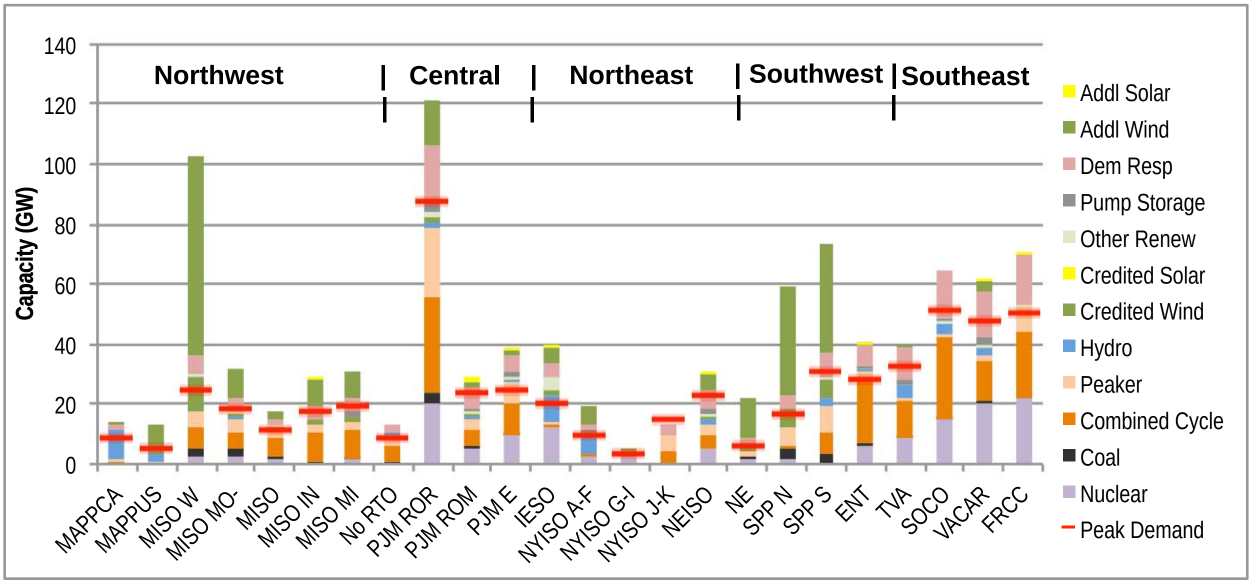


Fig. 84. Capacities and peak demand for each region for the CO_2+ scenario.

Table 42. Phase 2 Demand Response Capacity (in gigawatts and percent of demand) and Generation in NEEM Regions

Region	BAU Capacity (GW)	BAU Capacity (% Peak)	BAU Gener-ation (GWh)	RPS/R Capacity (GW)	RPS/R Capacity (% Peak)	RPS/R Gener-ation (GWh)	CO_2+ Capacity (GW)	CO_2+ Capacity (% Peak)	CO_2+ Gener-ation (GWh)
MAPP CA	0.6	6%	1	0.56	6%	0	1.49	18%	26
MAPP US	0.4	6%	-	0.39	6%	-	0.99	19%	119
MISO W	3.4	11%	-	3.26	11%	-	5.99	24%	3
MISO MO-IL	2.2	10%	-	2.17	10%	0	4.60	25%	139
MISO WUMS	0.8	5%	-	0.67	5%	-	1.80	16%	1
MISO IN	1.5	7%	0	1.83	7%	0	3.93	22%	14
MISO MI	3.1	13%	1	3.06	13%	0	4.04	21%	16
Non-RTO Midwest	0.7	7%	-	0.72	7%	-	2.46	27%	7
PJM ROR	10.2	9%	5	9.54	9%	7	18.79	21%	147
PJM ROM	3.5	12%	5	3.41	12%	4	7.32	30%	69
PJM E	2.5	8%	2	2.44	8%	3	5.85	23%	25
IESO	2.4	10%	-	2.39	10%	-	4.41	22%	0
NYISO A-F	1.2	10%	1	1.11	10%	1	2.14	22%	19
NYISO G-I	0.5	10%	1	0.42	10%	1	0.83	22%	6
NYISO J-K	1.8	10%	2	1.68	10%	2	3.27	22%	26
NEISO	4.3	15%	5	4.35	15%	4	6.28	27%	42
NE	1.0	14%	-	0.97	13%	1	1.75	30%	66
SPP N	1.5	7%	-	1.78	7%	2	3.81	23%	2
SPP S	3.7	10%	81	3.53	10%	5	7.68	25%	2
ENT	2.9	8%	0	2.83	8%	1	7.09	25%	5
TVA	3.4	9%	-	3.45	9%	-	10.49	32%	2
SOCO	7.5	12%	573	7.09	12%	135	15.60	30%	677
VACAR	5.9	10%	212	5.84	10%	64	15.12	32%	1,929
FRCC	5.9	10%	48	5.36	10%	24	16.72	33%	151

8.4 Southeast Demand Response Use and Price Impacts

The lack of local surplus wind and solar in the Southeast is further compounded in that DR cannot be used as reserves, so the regions must run their CC plants at partial load to supply required operating reserves while using DR to supply energy. This is shown for the CO_2+ scenario in Fig. 85 and Fig. 86 for the VACAR and SOCO regions on August 1. Demands increase throughout the day, and various technologies are added (at increasing cost) to respond. However, as demand continues to rise, CC generation declines slightly to provide a compensating supply of reserves. Peakers are added and pumped storage is used, and DR is called upon for a number of hours over the day. The gap between generation and load is supplied by imports. If DR or peakers could be used for reserves, then additional CC capacity could be used for generation. The figures also include the LMP for each region (a weighted average based on the prices and loads in the different BAs within the region.) The rise in prices as DR was called upon is readily apparent. If DR had been allowed to qualify for reserves, then less would have been dispatched and prices would have been lower.

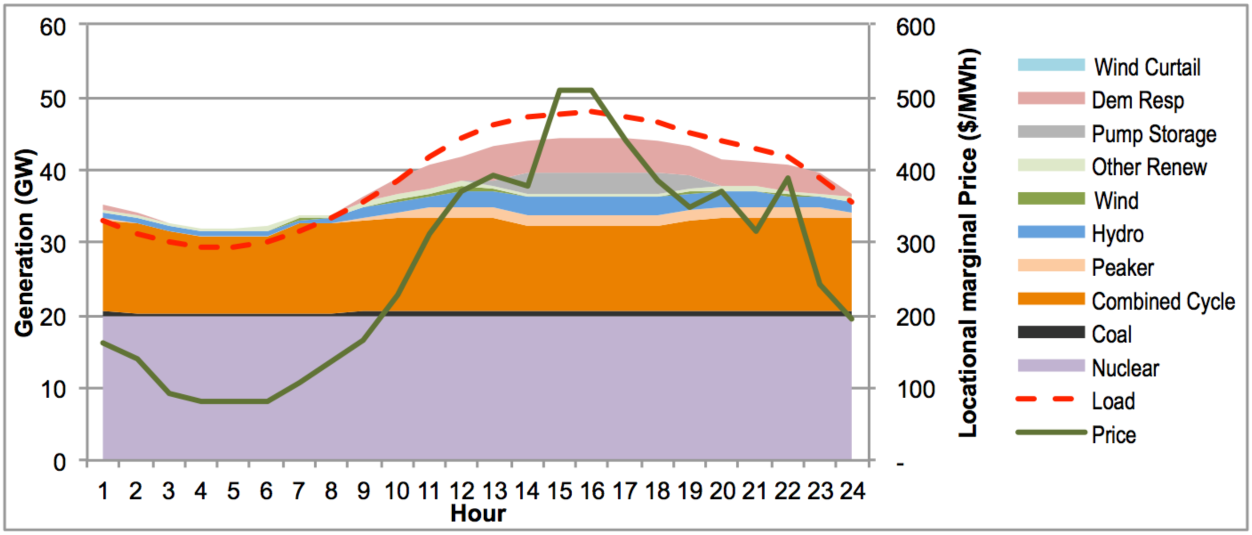


Fig. 85. VACAR generation, load and marginal prices on August 1 under the CO_2+ scenario.

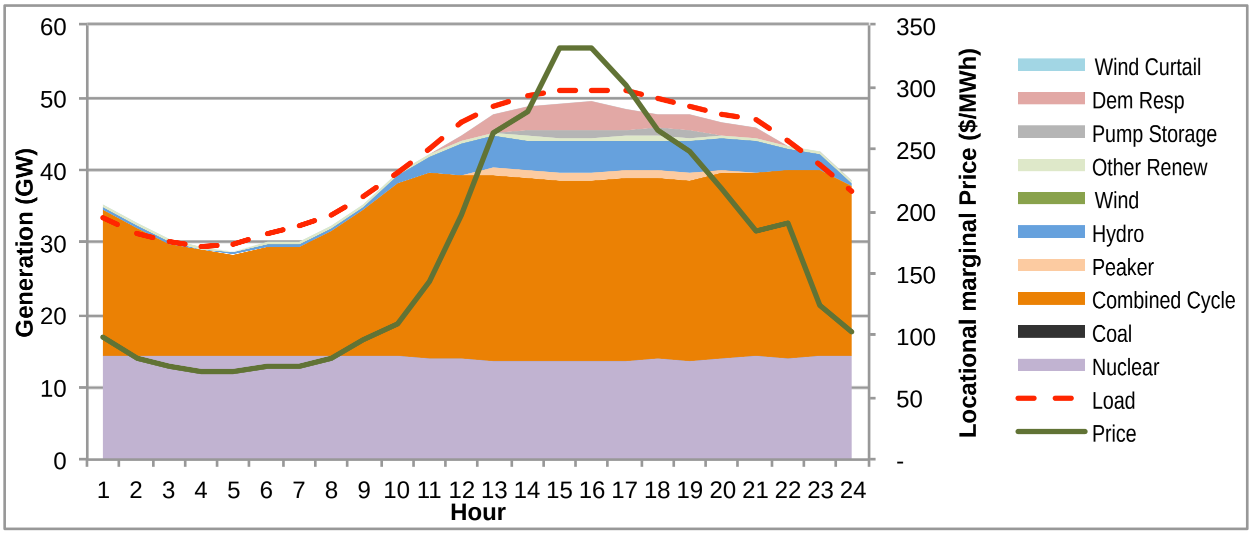


Fig. 86. SOCO generation, load, and marginal prices on August 1 under the CO_2+ scenario.

A key question that arose during the EIPC study was the lack of new lines in the Southeast despite high prices for the region, especially VACAR. The August 1 data are a case in point. VACAR can send and receive power from PJM ROR, SOCO, and TVA. In the scenario represented in Fig. 87, at 4:00 p.m. VACAR is receiving 4.5 GW of power from PJM ROR, which is near the maximum. It also receives a small amount from TVA and actually ships power to SOCO to supply its shortfall. SOCO is also using DR to meet demands while getting power from ENT, TVA, and VACAR and sending power to FRCC.

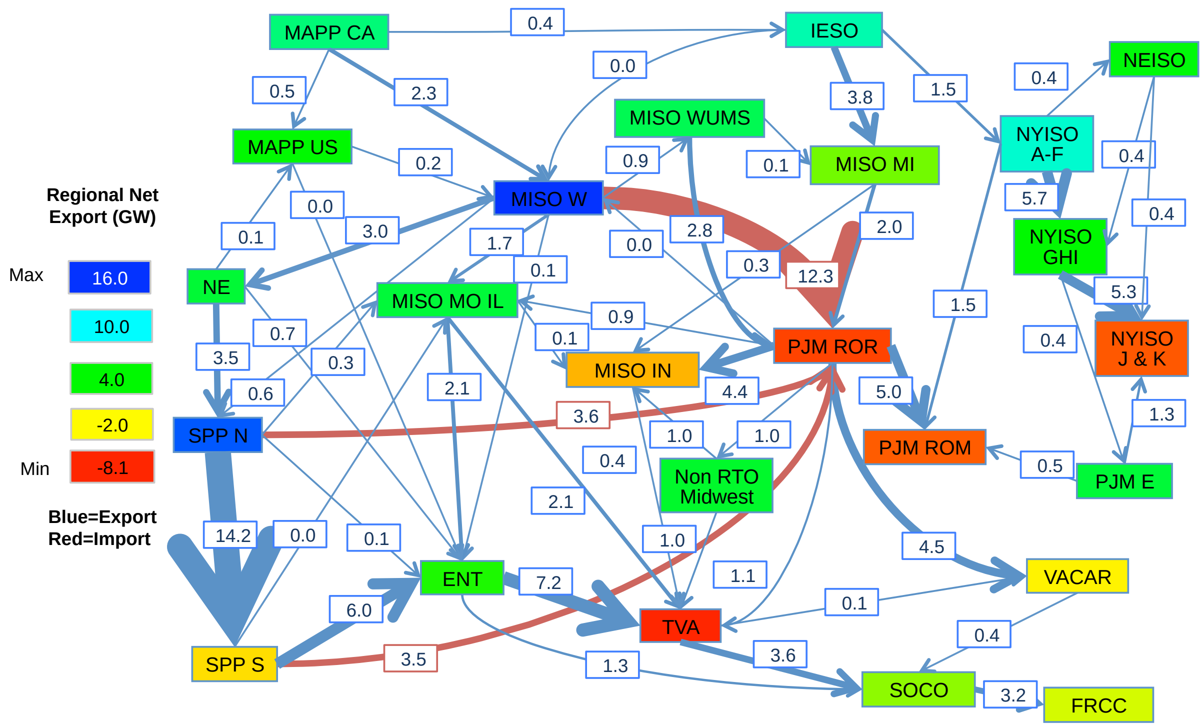


Fig. 87. Eastern Interconnection tie-line loads on August 1 at 4:00 p.m. for the CO_2+ scenario.

An examination of the flows and shadow prices on the individual flowgates to, from, and within VACAR show where some of the congestion occurs. There are three main flowgates from PJM ROR to VACAR; in this hour much of the power is flowing from central Virginia down toward central South Carolina, with a shadow price of $100/MWh. This represents the cost difference for power at either end of the line and indicates a congested line. (Other flowgates from PJM ROR do not appear to have shadow prices and so are not immediate congestion points.) Larger congestion occurs on the lines between SOCO and VACAR. There are three main flowgates between the two. Around 2.7 GW is flowing from VACAR to SOCO on the western link, but power is flowing in the other direction on the eastern two. Shadow prices are high on the line from Plant Vogtle into South Carolina, reflecting this line being highly constrained. A review of the PSS/E results indicates that this line is heavily loaded. There are also a few lines within the state that are congested in this hour, as shown by flowgate shadow prices.

Similar analyses show a mixture of congested lines within SOCO. While there were no shadow prices between it and ENT, within SOCO there were several lines indicating congestion, with marginal prices between $100/MWh and $500/MWh. These would indicate load pockets within the state that caused the dispatch of DR shown in Fig. 86.

As shown in Fig. 83, the DR capacity has a rising price as more is required. The DR was modeled by CRA as being spread across a region in proportion to its peak load, so DR can be called upon in load pockets even if the region as a whole has lower cost capacity available. Because DR generation was only reported at the NEEM region level and marginal prices at the BA level, while potential load pockets were at the bus level, it is difficult to show the relationship between prices and supply. However, by plotting the marginal prices within VACAR vs. the DR amounts a distinct supply curve appears.

Figure 88 plots the marginal prices for each of the six BAs in VACAR versus the total VACAR DR generation in the BAU scenario in the 412 hours where DR was dispatched. Three of the regions [Santee Cooper, Central Electric Power Cooperative, and South Carolina Electric and Gas (SCE&G)] have prices that stair step at DR levels of 300 MW, 600 MW, and 1,200 MW. The last one, SCE&G, is located in the southern part of the state next to Georgia, while the other two are cooperatives that purchase much of their power from the other utilities. As mentioned previously, there appears to be a transmission constraint between SOCO and VACAR, and so these areas are the first to reach constraints and need to dispatch DR.

The last three entries in the legend for Fig. 88 (Progress Energy, Duke, and Greenville Utilities) are located in North Carolina or the northern part of South Carolina. Their prices are lower and smoother than the first three utilities and are likely less constrained by having transmission access to PJM and TVA. The Progress and Greenville prices don't rise above $200/MWh until the total DR generation increases above 1,200 MW. DR for these two utilities starts being dispatched at this time, starting with the lowest cost supply for each. Duke prices are lowest, likely because it has the easiest access to the supplies of other regions. It likely does not start dispatching DR until the others have already begun using theirs. As DR continues to be dispatched, all utilities start to see increasing marginal prices, with some fluctuations at the highest levels where all utility prices become more highly correlated.

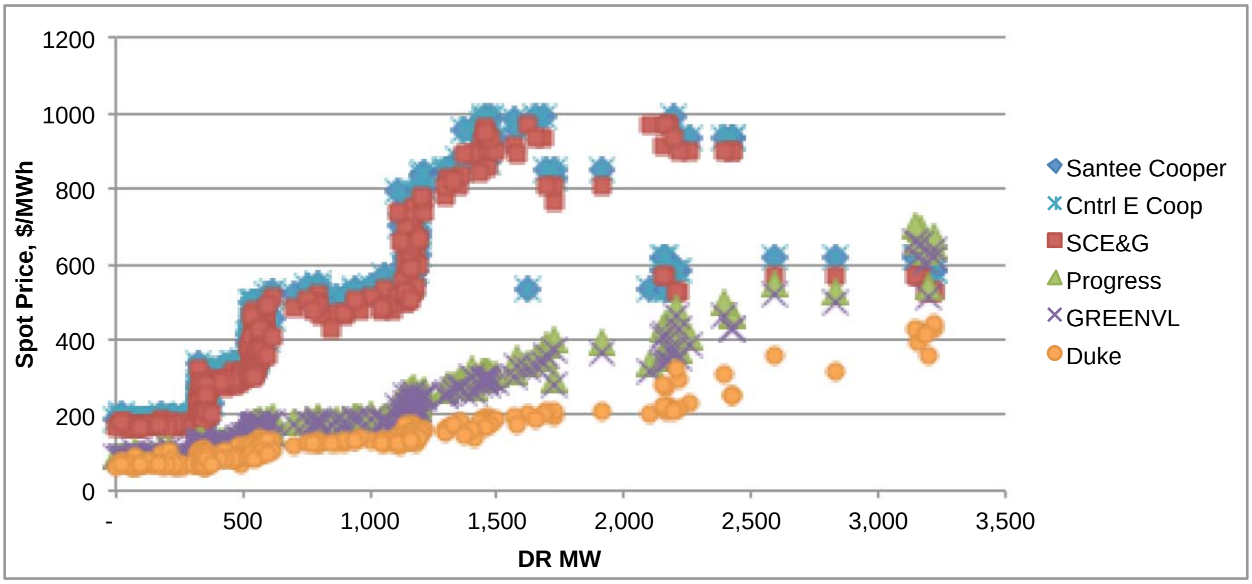


Fig. 88. Marginal prices at six balancing areas versus the corresponding DR demand for all of VACAR in the BAU scenario.

8.5 Southeast Transmission Build-Outs

If DR was needed for a number of hours in these scenarios, why were lines not built during Phase 1? In Phase 1, the initial NEEM run for each future established the marginal prices between regions and the second run calculated "soft" lines between each region based on those prices and the relative power needs. NEEM added soft lines that varied in capacity for each block of each year studied. Because a "real" line had to be set at a constant size for all blocks and years, the SSC had to calculate a representative size to "harden" the lines between regions.

In the case of the southeastern regions, the soft lines added by NEEM were used for roughly 20% of the year, during the peak periods. As an example, Fig. 89 shows the flow duration curves for the PJM ROR to VACAR tie-line in Phase 1 for several different study years. In Phase 1, members of the SSC Modeling Working Group (MWG) developed several complex methods that considered the capacity factors over multiple years to harden the lines. The results of the different methods are the data points on the baseline that represent existing capacity. The soft expansions in the Southeast were not used for a large enough fraction of the year to justify their construction as hardened lines in the Phase 1 modeling. Instead, it was more cost-effective to use DR or peaking plants for the time they would be needed. There could be additional factors such as hurdle rates between the regions or it could simply be due to the “peakiness” of loads in the south with higher summer demand.

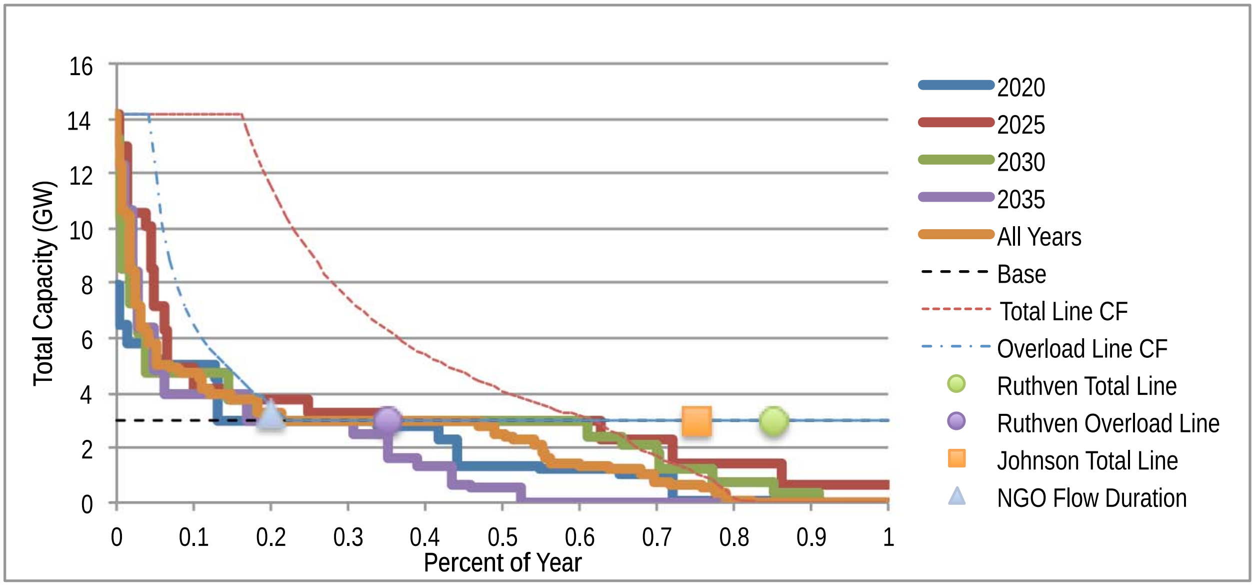


Fig. 89. Phase 1 CO_2+ flow duration curves for the “soft” tie-line between PJM ROR and VACAR.

In Phase 2, the build-out of lines was based on the results from Phase 1 plus the addition of lines solely for reliability purposes during the hour studied. Also, in Phase 2 the interregional flows were based on actual transmission lines and flowgates, so tie-line capacities could be different from Phase 1. Loop flows could also have limited the amount of net power transfer. As an example, Fig. 89 shows the Phase 1 flows with the existing capacity set at 3,000 MW, but in Phase 2 the maximum flow between PJM ROR and VACAR was 5,000 MW. Economics did not play a role in the build-out portion of the study. It was only in the last part when using GE MAPS that the full cost impact over the period was identified. In addition, there were one or two lines between SOCO and VACAR that should have been strengthened during the first part of Phase 2 but were missed by the planners.

8.6 Conclusions

The modeling efforts in this study provide only a rough approximation of the vital role DR can play in balancing supply and demand. The resource had to be modeled as a pseudo-generator with a price set high to model its limited availability. In Phase 1, because only a single price for all DR could be applied, it was set at roughly what the available models represented for the total potential supply. In Phase 2 a more complex supply curve with six price steps provided a more nuanced approach. Because DR was used in meeting the minimum planning reserve margin, some regions relied on it to meet their peak demand. In the CO_2+ scenario DR capacity was highest cost and those regions without access to surplus wind (most notably VACAR) used high levels of DR at consequent high prices. Some of this was due to the differences in the geographic, transmission, and time step detail in Phase 1 and Phase 2 modeling. At times, DR was called on because of transmission constraints that limited the ability to import power from other regions or elsewhere within a region.

9. TOPIC 9: "NO REGRETS" LINES

9.1 Transmission Elements Common to Multiple Scenarios

In Phase 2 a number of transmission components were included in the build-outs of each of the three scenarios to address reliability concerns. Because the scenarios capture significantly different outlooks for the future, there may be value in examining the components that show up in all three scenarios as they potentially represent elements that will be needed under a wide variety of future circumstances. If they were to be constructed, it would not be at the expense of other opportunities or more advantageous outcomes as it appears they will be needed regardless of what happens in the future.

An important consideration when examining the transmission elements that are common to all three scenarios is the development of the SSI in Phase 1. Before the MRN-NEEM runs, stakeholders identified new transmission and generation facilities that were to be included in the models. The SSI would eventually impact the transmission build-outs for all three scenarios as some of the elements common to all scenarios were added to fully integrate the SSI additions rather than strictly for reliability reasons.

Table 43 lists the number of transmission build-out elements that are common to all three scenarios by region and stated reason for inclusion. A large number of the NEISO elements resulted from the inclusion of a number of wind farms in the SSI. A number of lines and transformers were included to interconnect those facilities to the network.

Table 43. Elements in Common Across All Scenarios by Region

Region	Interconnect New Generation	Prevent Overloads	Prevent Low Voltage	Total
ENT		11		11
FRCC		3		3
MAPP CA		3		3
MISO IN		1		1
MISO MI		2		2
MISO W	1			1
MISO WUMS		1		1
NEISO	41	4	1	46
Non-RTO Midwest		1		1
NYISO		1		1
PJM ROM	2	2		4
PJM ROR		5		5
SOCO		3		3
VACAR	5	2		7
TOTAL	49	39	1	89

Of the 89 elements, 49 are new transmission lines, 14 are new transformers or autotransformers, 8 are new reactive support devices (reactors or static var controllers), and 18 are upgrades to existing facilities. A number of the new devices also require modifications to existing facilities (like adding bays to a substation), but they are classified as new here. In some instances, there were two separate circuits added between a pair of buses. Those are treated as separate lines for this purpose. (The appendix to this report is a list of the elements, including a description of the project and reason for its need.)

Most of the costs associated with the common elements are for connecting new generation, much of which is associated with the SSI. Table 44 shows the midrange estimate of the overnight capital costs of the common elements by reason of inclusion and the total costs from the three scenarios [from Table ES-3 of the EIPC Phase 2 Report (EIPC 2012)].

Table 44. Overnight Capital Costs (billions of 2010 dollars)

Costs	Common	CO_2+	RPS/R	BAU
Interconnect New Generation	5.7	49.6	54.3	7.3
Prevent Overloads	2.8	48.4	13.0	7.9
Prevent Low Voltage	0.04	0.5	0.1	0.2

Fig. 90 shows the locations of buses where the common transmission lines have a termination point or where common transformers or reactive support devices are located.

Fig. 90. Locations of buses with upgrades common to all three scenarios.

In some cases, elements were added or upgraded in each of the three scenarios, but the same thing is not done in each one. For instance, while one scenario may add an additional circuit to a transmission line, the others re-conductor the existing circuit. Alternatively, one scenario may include an element with a higher rating. While the stated reason is generally the same across all scenarios, this is not always the case. The scenario that used the least cost method is used for the reason in Table 45.

Table 45. Elements in Common with Different Methods by Region

Region	Interconnect New Generation	Prevent Overloads	Prevent Low Voltage	Total
ENT		1		1
FRCC		2		2
MAPP CA		5		5
MISO MI		2		2
MISO MO-IL			1	1
NEISO	1			1
PJM E	1			1
PJM ROM	3			3
PJM ROR	1			1
SPP S		7		7
VACAR	1	1		2
TOTAL	7	18	1	26

There are also a number of instances where an element shows up in two of the three scenarios. Of the total, 176 elements are common to the CO_2+ and RPS/R scenarios but not the BAU scenario. Many of these are in SPP and MISO as part of the wind collector systems. There are 50 pairs of buses that have entries in common with the CO_2+ and BAU scenarios but not the RPS/R scenario. There are 46 pairs of buses that have entries in common to RPS/R and BAU but not CO_2+.

9.2 Conclusions

There are 89 transmission elements that are common to all three scenarios. In another 26 instances something was done at a bus (or between a pair of buses) under each scenario, but the same thing was not done in all three. In many cases, the elements were included to support new generation that was included by the SSC in the early stages of the Phase 1 process. Those elements would only be “no regrets” if the associated new generation is actually constructed.

10. TOPIC 10: REGIONAL VERSUS NATIONAL IMPLEMENTATION OF POLICIES

During Phase 1 two sets of futures examined the effects of using a regional approach to policy issues versus a national approach. The first set (Futures 2 and 3) examined the impact of a CO_2 cost assigned to emissions; the second set (Futures 5 and 6) examined the implementation of a national RPS, either nationally (RPS/N) or regionally (RPS/R). This chapter examines the impact of a regional implementation in comparison to a national implementation for the CO_2 cost and RPS futures.

10.1 Definition of Superregions

For the two regional implementation futures in Phase 1 (Futures 3 and 6), NEEM regions were grouped into seven superregions. Transfer limits were allowed to increase within a superregion but not between superregions. Furthermore, the superregions formed the basis for the upper limit on the penetration of variable resources like wind and solar. Thus, compliance with national policy goals was forced to occur primarily within each superregion, with little contribution from imports from other superregions. The seven superregions are listed in Table 1. As mentioned previously, the seven superregions are slightly different than the five territories used elsewhere in this and the other reports. The superregions had important distinctions for modeling. Stakeholders wanted to capture the limits in transfer capacities between eastern and western PJM and between Ontario and the Northeast. Also, in Phase 1 the Non-RTO Midwest region was not connected electrically with PJM, so it needed to be included in the Midwest superregion. Territories are more consolidated and just used for reporting purposes.

As opposed to the regional analysis, in the two national implementation futures implementation could be carried out across the EI as a whole (without Canada). Transfer limits were allowed to increase between any adjoining regions regardless of the superregion in which they were located. Also, the CO_2/N (i.e., high CO_2 cost, implemented nationally) future aggregated the EI into four defined regions where each had a maximum intermittency share of 35% (Southeast plus Southwest regions, Midwest plus PJM regions, Ontario, and the Northeast) while the CO_2/R (i.e., high CO_2 cost, implemented regionally) future applied the intermittency limits to the seven smaller superregions.

10.2 Definition of the Two Policies

10.2.1 Carbon Dioxide Prices

Carbon dioxide price penalties for Futures 2 and 3 were developed using the MRN-NEEM model in an iterative fashion to find the CO_2 prices that would lower economy-wide emissions from 2005 levels 42% by 2030 and 80% by 2050. This was done originally for the national implementation (Future 2), and the resulting prices were also used for the regional implementation (Future 3). The resulting CO_2 prices (in 2010 dollars) were $27/ton in 2015, $140/ton in 2030 and $369/ton in 2040, with additional increases afterwards. Further discussion on the CO_2 prices is in Sect. 12.1, where variations on the CO_2 price are examined.

The differences between the national and regional implementation of the carbon constraint futures stem from two factors: limitations on transfer limits between the superregions and the level of aggregation for the intermittent resource penetration limit. While the national implementation allowed all transfer limits to be expanded, the regional implementation did not allow expansion of the transfer limits between superregions. While both imposed a 35% limit on the penetration of intermittent resources, the national implementation applied that limit to each of four larger areas while the regional implementation applied it to the seven superregions. This allowed for a larger penetration of intermittent resources under the national implementation within individual NEEM regions as the overall pool that the region was in was larger.

10.2.2 Renewable Portfolio Standard

The RPS in Futures 5 and 6 requires that 7.5% of overall energy in 2015 be generated from a renewable source, which is defined as biomass, geothermal, hydroelectric, landfill gas, solar, and wind. The RPS requirement increases over time to 30% in 2030.

There are three differences between the national and regional implementations of the RPS. These are the two identified for the CO_2 prices, limitations on transfer limits and level of aggregation for intermittent penetration limits, and the level of aggregation for the renewable standard itself. In the national implementation, the RPS must be met on an EI-wide basis. In the regional implementation, each superregion must supply its own resources to meet the standard within the superregion. In effect, the national implementation allows one superregion to be under the standard as long as other superregions make up the difference (subject to the intermittent penetration limit for each of the four large areas).

10.3 Method of Analysis

This chapter uses the MRN-NEEM results from Phase 1 to examine the effects of regional versus national implementation for the CO_2 cost and RPS futures. A number of sensitivities were developed in addition to the base case for each of the futures in Phase 1. In a number of cases, parallel sensitivities were run for both the national and regional implementation futures using variations in load growth, natural gas prices, carbon prices, and capital costs of specific technologies. However, as the impacts of these variations are covered in other chapters of this report, this chapter focuses on a comparison of the base cases with hardened transmission limits.

10.4 Results

10.4.1 Carbon Dioxide Prices

The national implementation of CO_2 prices resulted in a dramatic shift away from coal toward natural gas and wind, with the retirement of 250 GW of coal-fired capacity in the EI by 2030 and the addition of 299 GW of onshore wind and 118 GW of natural gas CC capacity. More than 70% of the wind generation was located in either the MISO or SPP regions.

While the regional implementation of CO_2 prices also resulted in a shift away from coal toward natural gas and wind, the effect was somewhat altered: 241 GW of coal was retired in the EI by 2030 and only 179 GW of onshore wind was added. Roughly half of the wind capacity was located in MISO and SPP. The amount of natural gas CC capacity increased to 143 GW. The changes were driven largely by a shift from a heavy reliance on wind from the western regions under the national implementation to more local sources in the eastern regions due to the lower transmission limits under the regional implementation.

This resulted in a significant drop in energy from renewables with a correspondingly large increase in energy from natural gas, as is shown in Fig. 91. Use of both coal and nuclear sources also increased under the regional implementation.

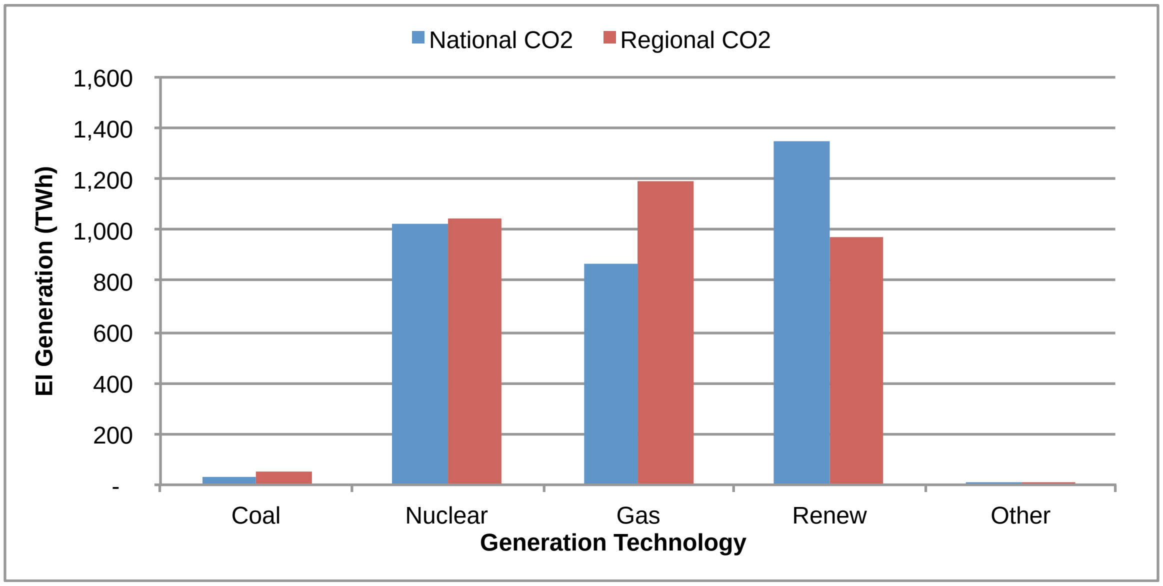


Fig. 91. Eastern Interconnection generation by type in 2030 under CO_2 futures.

As shown in Fig. 92, generation levels in the Southwest and Midwest dropped under the regional implementation (as compared to the national implementation). Generation increased in the Southeast and PJM ROR superregions. The Midwest superregion had less wind, more natural gas, and reduced exports under the regional implementation. The Northeast saw little change between the two, while PJM MAAC saw little change until after 2030. PJM ROR had more wind under the regional implementation and became a net exporter. The Southeast superregion imported less and generated more from natural gas under the regional implementation. The Southwest had much less wind, more natural gas, and no exports under the regional implementation. A visual comparison of the generation sources for each of the superregions over the study period is provided in the appendix of this report.

With the reduction in wind generation and increased generation from natural gas and coal, the regional implementation produced more CO_2 emissions. Because the CO_2 prices were determined based on achieving the desired emissions reduction for the national implementation, this indicates that the regional implementation would not achieve that level of emissions reductions. A higher CO_2 price, at least for some superregions, would need to be implemented to achieve an equivalent level of emissions reduction.

The national implementation resulted in lower fuel costs and emissions costs, as shown in Fig. 93. The regional implementation resulted in lower capital costs and O&M costs. The national implementation showed an annualized net present value of costs that is about $17 billion higher than the regional, when high-level transmission capital costs are included, due to the 40 GW of new transmission capability at $30 billion in that case versus the regional implementation addition of 5 GW at just $2 billion, Thus, the national implementation achieved a greater level of CO_2 emissions reductions, but at a higher cost.

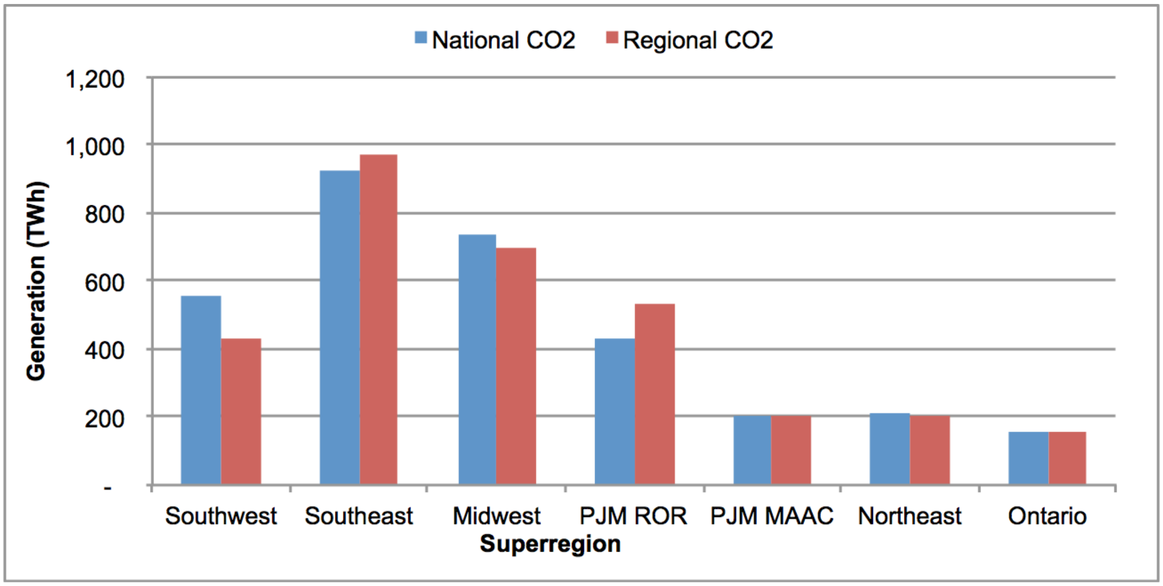


Fig. 92. Eastern Interconnection generation by superregion in 2030 under CO_2 prices.

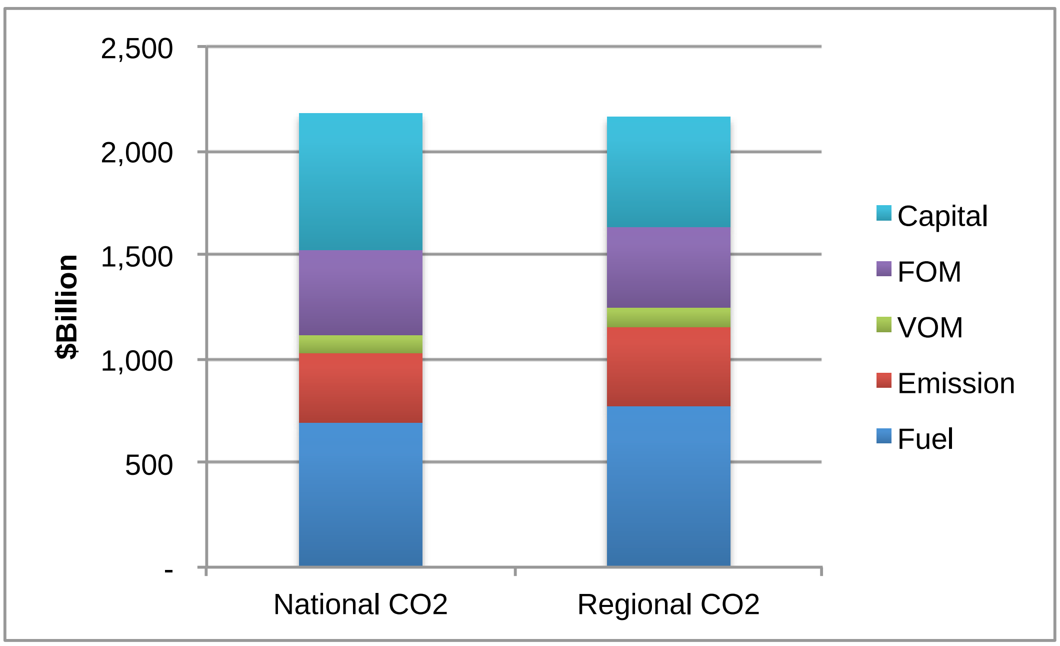


Fig. 93. Net present value costs, 2015–2030, under CO_2 prices.

10.4.2 Renewable Portfolio Standard

Unlike the CO_2 price futures, the impact of regional versus national implementation of an RPS had little impact on coal and natural gas use over the EI. The primary effect was that the regional implementation relied less heavily on wind from the Midwest and Southwest superregions and more heavily on offshore wind and biomass in the eastern portions of the EI.

Coal retirements under both RPS implementations were 102 GW. The regional implementation had less new natural gas CC capacity (30 GW vs. 40 GW) and onshore wind (141 GW vs. 198 GW), while it had more offshore wind (38 GW vs. 1 GW) and other renewables (33 GW vs. 10 GW).

This resulted in very little change in energy from coal and nuclear, as shown in Fig. 94. Natural gas generation was down slightly in the regional implementation. Onshore wind generation was down by 36% in the regional implementation, while both offshore wind and biomass made significant contributions.

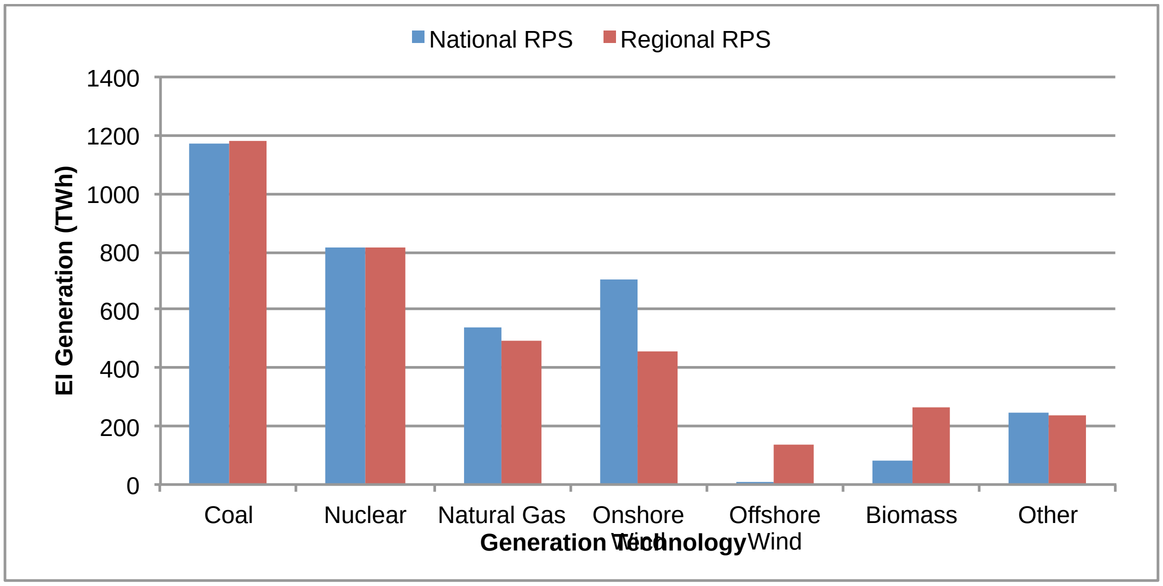


Fig. 94. Eastern Interconnection generation by type in 2030 under the renewable portfolio standard (RPS).

From a regional perspective, the Midwest superregion had less wind, with more natural gas and coal, in the regional implementation than in the national. The Northeast had more natural gas and lower imports in the regional implementation. PJM MAAC had more offshore wind and less generation from coal and natural gas in the regional implementation, while PJM ROR had more onshore wind, less natural gas, and became a net exporter. The Southeast had more offshore wind and other renewables, with less coal and natural gas in the regional implementation. The Southwest had much less wind and more coal and natural gas and did not export in the regional implementation. Figure 95 shows the comparison of total generation under the two implementation strategies, and a breakdown by source is provided in the appendix.

Because it is better able to take advantage of the abundant wind resources in the Great Plains, the national implementation results in lower fuel, capital, and O&M costs as shown in Fig. 96. On a net present value basis, the national implementation is roughly $86 billion lower than the regional implementation. This is despite the fact that the national implementation includes 64 GW of additional transmission capacity at a cost of $36 billion compared to only 3 GW and $2 billion for the regional implementation.

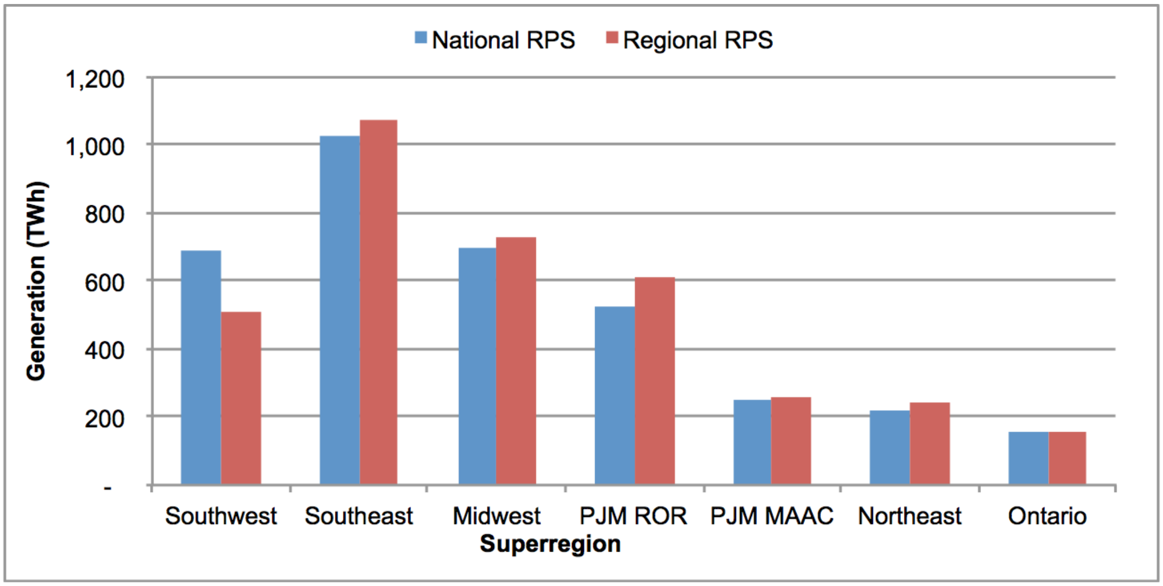


Fig. 95. Eastern Interconnection generation by superregion in 2030 under the renewable portfolio standard (RPS).

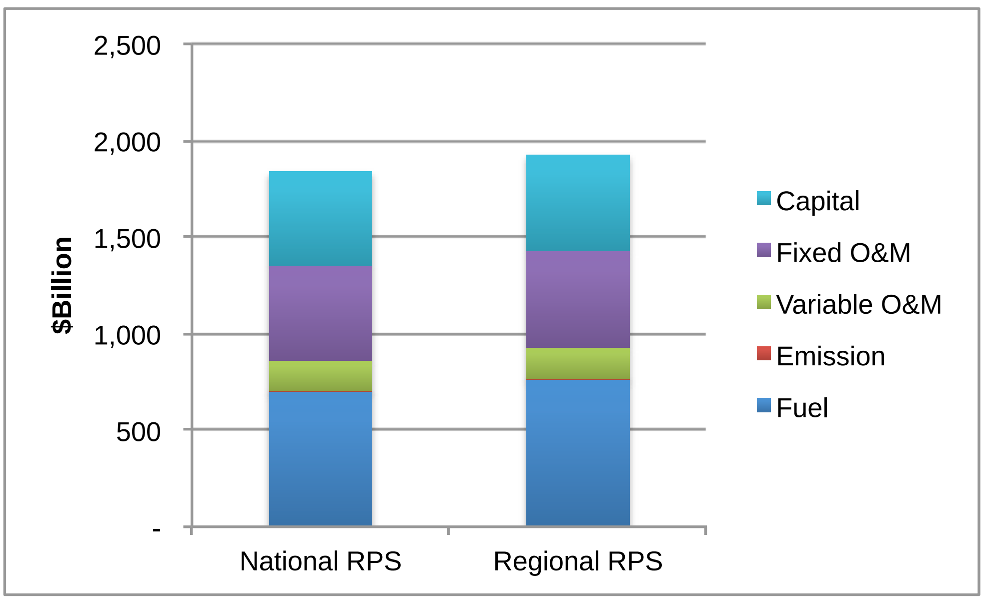


Fig. 96. Net present value costs, 2015–2030, under the renewable portfolio standard (RPS).

10.5 Conclusion

As was intended when the futures were developed, the switch from a national implementation to a regional implementation caused reduced reliance on interregional transfers of energy and increased reliance on local generation. Under both the CO_2 price and RPS futures, wind generation in the Southwest and Midwest superregions were lower for the regional implementation. The replacement for the displaced wind energy was different in the CO_2 price future than in the RPS. The regional CO_2 price resulted in increased use of fossil fuels, especially natural gas, while the regional RPS saw increased use of offshore wind and other renewables such as biomass.

The regional CO_2 price led to greater CO_2 emissions than the national CO_2 price, but at a slightly lower cost. The RPS/R future had higher overall costs than the RPS/N future.

11. TOPIC 11: LOAD GROWTH SENSITIVITIES

11.1 Base Growth Rates

The initial futures had demands based on expected growth rates as determined by the planning authorities and the SSC as shown in Table 46. Those shown are for the BAU future; the other futures began with these values but could vary because the MRN economic model incorporated price elasticity to reduce demands as prices rose. In addition, the EE/DR and CO_2+ futures included a 1% reduction in growth rates to represent the impact of EE programs. Each region can have a different growth rate depending on its expected use patterns and economic growth. Some regions have flat to negative growth (e.g., PJM E and NEISO) based on their existing EE plans.

Table 46. Demand Growth Rates for the Business as Usual Future

NEEM Region	2011 Energy (GWh)	2011–2020 Growth Rate (%)	2020–2050 Growth Rate (%)
MAPP CA	48.1	2.00	0.78
MAPP US	29.8	0.87	0.78
MISO W	137.7	0.85	0.78
MISO MO-IL	96.2	0.87	0.82
MISO WUMS	66.4	1.10	0.66
MISO IN	97.1	1.05	0.61
MISO MI	94.7	0.80	0.79
Non-RTO Midwest	58.1	1.66	0.49
PJM ROR	520.0	0.40	0.61
PJM ROM	144.0	0.86	0.67
PJM E	135.8	-0.98	0.67
IESO	142.3	-0.29	0.67
NYISO A-F	63.3	0.20	0.51
NYISO G-I	19.5	0.14	0.85
NYISO J-K	73.3	0.39	0.88
NEISO	129.8	0.02	0.00
NE	29.5	1.81	0.78
SPP N	76.0	1.22	0.91
SPP S	163.9	1.15	0.64
ENT	159.5	1.37	0.53
TVA	173.6	0.97	0.49
SOCO	249.5	1.94	0.81
VACAR	236.1	1.62	0.96
FRCC	229.0	1.73	1.24
Total EI	**3,173.2**	**0.92**	**0.72**

To examine the impact of growth, sensitivities that either raised or lowered the growth rates were run for many of the regions. The rates were changed by adding or subtracting 1% to the annual rate, so for example, a growth rate of 0.85% became either 1.85% or −0.15% depending on the sensitivity. Load growth sensitivities were run in six different futures: the BAU, CO_2/N, CO_2/R, RPS/N, RPS/R, and NUC. The first three included both high and low load growths, but only high load growth impacts were evaluated for the last three.

The consequent growth rates led to widely different growth levels between 2011 and 2030 for each of the regions (Table 47). Growth was highest in the Southeast territory, followed by the Southwest, Northwest, Central, and Northeast. Under high demand, growth overall exceeded 40% by 2030, while with low growth, the demand in the EI actually shrank.

Table 47. Growth by Region for Base, High, and Low Sensitivities (2011–2030)

NEEM Region	Low Demand (%)	Base (%)	High Demand (%)
MAPP CA	7	29	56
MAPP US	−3	17	41
MISO W	−4	17	41
MISO MO-IL	−3	17	42
MISO WUMS	−3	18	42
MISO IN	−4	17	41
MISO MI	−4	16	40
Non-RTO Midwest	1	22	47
PJM ROR	−9	10	33
PJM ROM	−5	15	39
PJM E	−19	−2	18
IESO	−14	4	26
NYISO A-F	−12	7	29
NYISO G-I	−9	10	33
NYISO J-K	−7	13	37
NEISO	−17	0	21
NE	5	27	53
SPP N	1	22	48
SPP S	−2	18	43
ENT	−2	19	44
TVA	−5	15	38
SOCO	6	29	56
VACAR	5	27	54
FRCC	9	32	60
Total EI	**−4**	**17**	**41**

Growth in demand can influence marked changes in the amount of transmission that is needed for reliability or to improve economics. In many cases higher demand will lead to the need for increased transmission capacity, but not in all cases. There can be occasions where reduced demand near a low-cost resource will lead to calls for increased transmission capacity to facilitate export to distant load centers. Once transmission capacity is constructed, the relative cost differences between regions, including hurdle rates and/or wheeling charges, will determine actual transfers at any point in time.

11.2 Demand Effects on Transmission

In his 2004 paper for DOE and the Edison Electric Institute, Eric Hirst identified four broad reasons for construction of new transmission (Hirst 2004).

- Interconnection of new load or generation: Facilities required to connect to the transmission grid, but not necessarily to transport power across the grid.
- Reliability: Facilities required to meet NERC (North American Electric Reliability Corporation), regional reliability council, and other standards, primarily the NERC (1997) *Planning Standards*.

- Economics: Facilities that lower the cost of electricity production by reducing losses and congestion to permit greater use of low-cost generators to serve distant load centers.

- Replacement: Facilities that replace old, worn-out, and/or obsolete equipment.

In addition, a fifth reason has become more prevalent.

- Environmental: Facilities required to interconnect clean resources such as renewables to load for society to meet portfolio standards or other policy goals.

Demand changes can affect transmission capacity needs in all of these categories.

Interconnection. If demand is lowered or DG increased at the end-user location, then fewer or less expensive interconnections of new load or generation are needed, while increases in demand can increase the interconnections needed.

Reliability. Generation planning reserves are a function of the expected peak demand, so demand changes will raise or lower the need for planning reserves and thereby interconnections. On an operational basis and to meet contingencies, the system must maintain operating reserves based on demands at any point in time. Demand changes will have a direct effect on the transmission and distribution resources needed to support the operational reserves and meet contingencies.

Economics. Demand resources can compete with supply both indirectly as customers invest in EE and directly as DR bids into the wholesale markets in several regions of the country. Their deployment near loads reduces the capital cost of transmission and the transmission losses from bringing power from more distant plants. Increased demands raise the amount of generation required. If the new generation comes from distant sources then transmission will be needed. However, if the generation uses fuel sources that can be more easily or cheaply transported (e.g., natural gas through pipelines), then new transmission will less likely be needed.

Replacement. EE and DR reduce demand, so they may reduce the need for or size of replacement capacity when equipment becomes worn-out. However, this effect may be limited on the distribution side depending on how local power companies size their replacements. DG may similarly reduce the need, but because it can feed power back into the grid, upgrades to the local distribution system may be required. DR and DG also require enhanced communication capabilities (i.e., smart grid) for them to be used to full effect. This may lead to making some equipment obsolete and requiring earlier replacement.

Environmental. Reduced demand will help to avoid emissions from generation and avoid land and water impacts from generation and transmission capacity. Many portfolio standards and other policies recognize the benefits of increased EE in the establishment and calculation of standards. However, there can be an increase in transmission demand if the lowered demand is near environmentally attractive or economic generation resources that are limited geographically. These freed up generation resources may need added transmission resources to carry their production to more distant loads.

11.3 Key Impacts

For every future the transmission system was only expanded during development of the base scenario. A three step process consisting of the following was used (1) run the MRN-NEEM with the input assumptions for the future and no change to the transmission system, (2) use the consequent regional cost differences to allow the model to build variable capacities of transmission between regions, and (3) harden the sizes of the resulting transmission to be the same over the study period. This method was not applied to each sensitivity, since sensitivities by definition are modest changes to one or a few inputs without major changes to the future as a whole.

11.3.1 Transmission Changes

Because transmission capacity between regions was not changed with the increase or decrease in growth rates, there was little actual change in the amount the transmission grid was used despite the change in demand; either the maximum interregional flow or total energy transferred over the system. Figure 97 shows both of these factors as x-axis and y-axis values for the base and sensitivities with load changes. The clumping together of similar future results (shown by the colors of the data points) indicates that neither the total energy transferred nor the peak amount during the year varied greatly within the future.

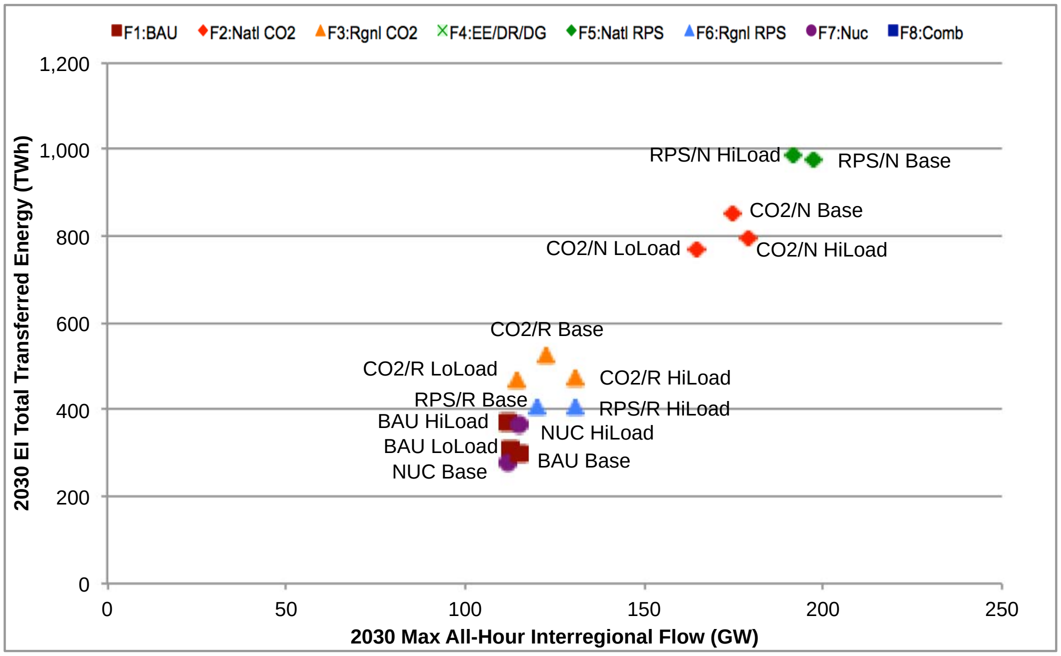


Fig. 97. Eastern Interconnection (EI) total interregional transfers (TWh) versus peak flow (GW) in 2030 under different load growth scenarios.

The nationally implemented RPS cases had the highest amount of flow, both peak and summed over the year (green diamonds in Fig. 97). This future had the largest amount of transmission capacity added in the base scenario, 64 GW, of the futures. The high load sensitivity had higher overall flows but lower peak flows than the base case for that future. Both of the CO_2 futures had their peak flows consistent with load levels, but in terms of overall energy flow, the base cases were the highest. Other futures showed a mix of increases or decreases that were not necessarily correlated with the load levels.

11.3.2 Supply Mix Changes

Fig. 98 shows the EI generation amounts in 2030 by technology for the base case and sensitivities. As shown in Table 48, the total generation amounts changed by less than 25% up or down. Natural gas generation shifts the most between the base and sensitivities for each future with variations ranging from +90% to −49% in the high and low load sensitivities. Coal as a percentage change was quite high in the two CO_2 futures, but that is not significant because the amount of coal generation is near zero in those cases. Renewable amounts change roughly in line with the total percentage change, while nuclear generation changes little. Changes to renewables in the RPS futures would of necessity change at about the same rate as the total as their share of the market is defined by the RPS.

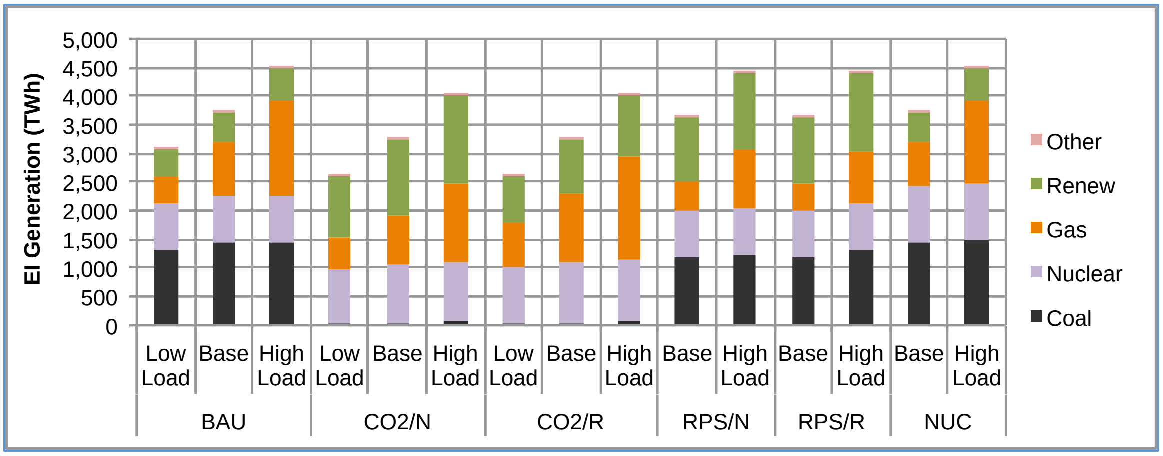


Fig. 98. Eastern Interconnection (EI) generation by technology in 2030 under different load growth scenarios.

Table 48. Percent Change in Generation from Base Scenario for Each Future by Technology

Future	Sensitivity	Coal	Nuclear	Gas	Renew	Other	Total
BAU	Low Load	−9	0	−49	−8	−33	−17
	High Load	2	0	73	8	3	21
CO_2/N	Low Load	−44	−5	−36	−20	−20	−20
	High Load	123	4	57	15	27	24
CO_2/R	Low Load	−55	−3	−35	−16	−13	−20
	High Load	38	2	51	13	49	24
RPS/N	High Load	5	0	90	20	20	21
RPS/R	High Load	12	0	84	19	37	21
NUC	High Load	3	0	93	7	−15	21

11.3.3 Regional Changes

Most regions had similar changes in generation levels as demand increased or decreased (Fig. 99). With no change in transmission capacity and little change in actual transfers between regions, it follows that each region increased or decreased its generation to meet the change in demand. However, in a few futures, certain regional changes stand out. These are highlighted in Table 49, which shows the percentage change for each territory from the base scenario of each future. In the CO_2/N future, the Central region (mainly PJM) had bigger swings in its generation levels than the other regions. In that future, the region imported large amounts from the Midwest, and as shown in the previous study (Hadley and Gotham 2014), the transfers between the regions hit the capacity limits much of the time. With the demand increased, the region had to generate proportionately more to meet demand. Conversely, with lower demands the lines between the regions were constrained less frequently and more power could transfer from the Midwest, further reducing the need for generation in the Central region.

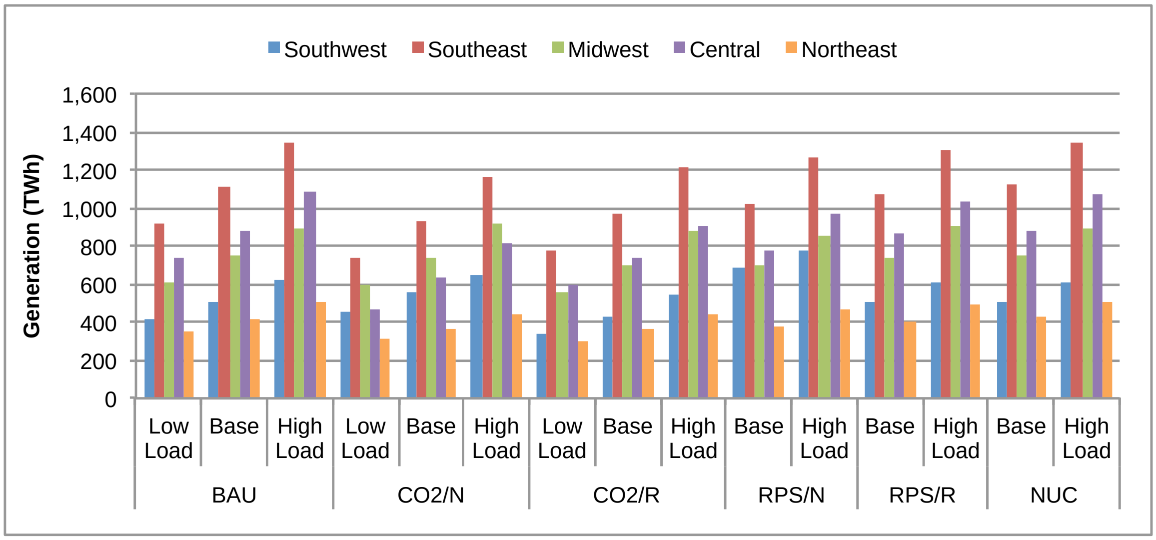


Fig. 99. Eastern Interconnection generation by territory in 2030 under different load growth scenarios.

Table 49. Percent Change in Generation from Base Scenario for Each Future by Territory

Future	Sensitivity	Southwest	Southeast	Midwest	Central	Northeast	Total
BAU	Low Load	−19	−18	−19	−16	−16	−18
	High Load	22	20	18	23	22	21
CO_2/N	Low Load	−17	−20	−19	**−25**	−16	−20
	High Load	17	26	24	**29**	20	24
CO_2/R	Low Load	−20	−20	−21	−20	−16	−20
	High Load	26	25	25	23	21	24
RPS/N	High Load	**13**	24	22	25	23	22
RPS/R	High Load	21	22	23	19	24	21
NUC	High Load	21	20	20	23	20	21

In the RPS/N future, the effect on the Southwest was opposite that on the Central region. It exported significant amounts of power to the Southeast and Central regions. The lines were fully loaded much of the time; under higher demands they could not ship proportionately as much power to the east. As a consequence, its percentage increase in generation was lower than that of the other regions.

11.3.4 Regional Cost Changes

Costs of course increase with higher demands and decline with lower demands. Figure 100 shows the cost by territory for the base and load growth sensitivities. The Southeast, Midwest, and Central territories dominate the costs, although the Southwest has relatively high costs, especially in the RPS/N future where it provides its most significant contribution through wind generation. (These costs are those calculated within the MRN-NEEM model and do not include transmission and distribution, EE/DR, and a few smaller cost components calculated externally to the model.) The percentage changes from the base future are shown in Table 50. The Southwest territory generally sees smaller differences in cost as demand increases or decreases. Transmission limits constrain higher generation and costs for supplying exports to other regions, while declines in demand free up transmission space for increased exports. On the other hand, the Central and Northeast regions have larger increases in costs than the average with higher demands because they must generate more of their own power. Because much of that power will be either gas generation or higher cost renewables, their costs will go up proportionately. In addition, the transmission constraints mean that imports will be a smaller proportion of their total generation so that internal generation costs rise proportionately.

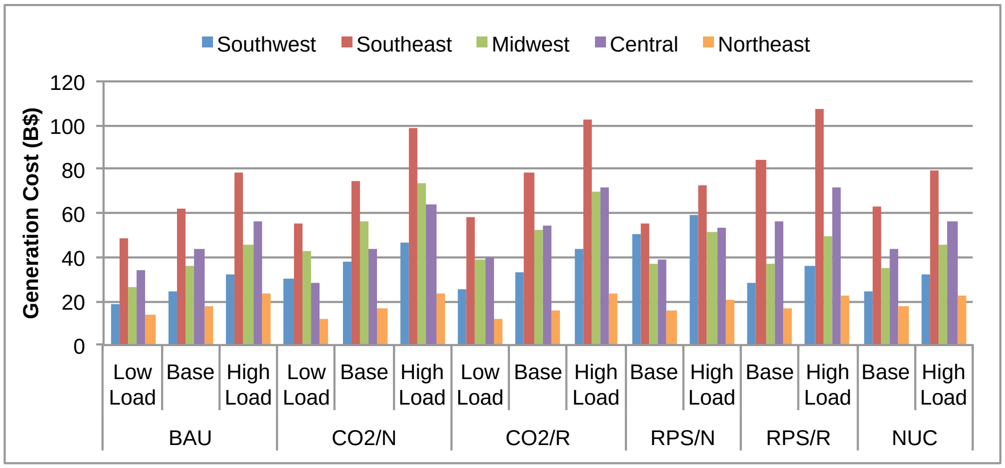


Fig. 100. Eastern Interconnection generation cost by territory in 2030 under different load growth scenarios.

Table 50. Percent Change in Cost from Base Scenario for Each Future by Territory

Future	Sensitivity	Southwest	Southeast	Midwest	Central	Northeast	Total
BAU	Low Load	−25	−22	−27	−22	−22	−24
	High Load	32	26	28	30	33	29
CO_2/N	Low Load	−20	−25	−25	−36	−26	−26
	High Load	23	33	31	45	44	34
CO_2/R	Low Load	−24	−25	−25	−27	−24	−25
	High Load	31	31	32	32	46	33
RPS/N	High Load	17	31	39	38	34	30
RPS/R	High Load	27	28	34	28	34	29
NUC	High Load	29	26	30	31	31	29

11.4 Conclusions

Because load growth changes were made to the different futures after the transmission capacity between regions was set, there was little change in the amounts transferred between regions. Rather, natural gas generation, which was modeled as available in any region, was most often added or subtracted in each region as needed. Those constraints meant that regions that exported significant amounts could not increase their exports in line with the growth in demand and so did not have as strong a growth in generation, while importing regions had to expand their internal generation proportionately more. Cost changes tended to mirror generation changes but with some amplification because higher cost generation was the marginal amount added.

12. TOPIC 12: ENVIRONMENTAL POLICY SENSITIVITY IMPACTS

A large number of the futures and sensitivities were defined to explore the effect of different environmental policies. The futures themselves looked at the major policies of CO_2 price inclusion, aggressive EE/DR/DG, RPS, NUC, or a combination of these factors. Within each, as well as the BAU, environmental policies were strengthened, reduced, or combined. This chapter looks at the effects of these modifications to the environmental policies in place in the different futures.

12.1 Carbon Pricing

Carbon pricing was a major component for three of the futures (CO_2/N, CO_2/R, CO_2+) and a sensitivity in the NUC future. This section focuses on the effect of the different CO_2 price penalties within each policy and not the effects between futures. Five sensitivities allow a check on changing CO_2 prices compared to their bases. Table 51 shows the mix of capacities for the EI in 2030 in those different scenarios. “Other” includes both pumped storage and DR, which were put into the model and did not vary in the cases shown in the table.

Table 51. Capacities in 2030 by Technology for Base and CO_2 Sensitivities of Three Futures (GW)

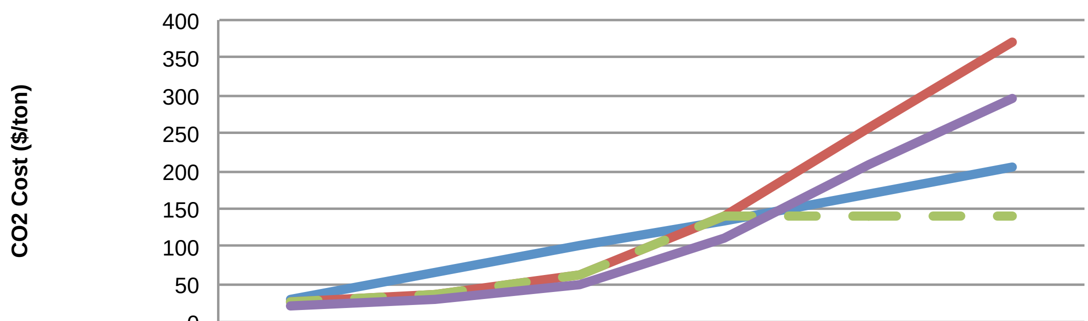
Case	Coal	Nuclear	Gas	Renewables	Other
CO_2/N Base	31	131	364	398	88
CO_2/N Flat CO_2	12	127	388	392	88
CO_2/N Low CO_2	34	114	383	358	88
CO_2/R Base	39	134	372	280	88
CO_2/R Flat CO_2	12	133	402	267	88
CO_2/R Low CO_2	33	112	402	251	88
NUC Base	199	129	340	142	88
NUC CO_2 added	63	191	409	195	88

The goal of the futures involving CO_2 prices was to lower economy-wide emissions from 2005 levels 42% by 2030 and 80% by 2050. Rather than attempt a long series of automated iterations to establish a price for each year studied, the SSC set initial prices at \$30/ton in 2015, increasing by \$7/year, and then let CRA adjust them to meet the goals. CRA had to run the MRN-NEEM several times to establish a price curve that met the requirements. One outcome was that in the years up to 2030 most carbon reduction came from the electricity sector so that while the economy as a whole had a reduction of 41% in emissions, the electricity sector had a reduction of 78%. By 2040, the electric sector was essentially “decarbonized.” Table 52 shows the CO_2 emissions for the United States as a whole and for the US electric sector from the BAU base case and the initial CO_2/N case. (Electricity transfer capacities were subsequently hardened to create the CO_2/N base case.)

The resulting CO_2 price curves are shown in Fig. 101. The preponderance of reductions in the electricity sector makes sense as the substitutes for CO_2-emitting generation are relatively well known and inexpensive. Other sectors, notably transportation, may have a difficult time making reductions as significant as these, at least as modeled in MRN-NEEM.

Table 52. US CO_2 Emissions in the Business as Usual and CO_2/N Base Scenarios (billion tons)

United States Economy as a Whole								
	2015	2020	2025	2030	2035	2040	2045	2050
BAU Base	5.7	5.6	5.8	5.9	6.2	6.5	6.9	7.3
CO_2/N Base	4.9	4.4	4.0	3.5	2.9	2.3	1.8	1.2
Percent reduction from BAU	13	21	31	41	54	64	75	84
Target emissions				3.5				1.2
US Electric Sector								
	2015	2020	2025	2030	2035	2040	2045	2050
BAU Base	2.1	2.0	2.2	2.2	2.4	2.6	2.9	3.2
CO_2/N Base	1.60	1.1	0.7	0.5	0.3	0.1	0.1	0.04
Percent reduction from BAU	25	47	67	78	89	96	98	99



	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

Fig. 101. Carbon dioxide price curves used in study.

The later years saw rapidly increasing CO_2 prices, with the cost by 2045 at \$553/ton and by 2050 at \$942/ton (beyond the scale in Fig. 101). This was a result of the extreme amount of CO_2 emissions reductions required and possibly because the model had few levers to drastically change CO_2 emissions in the transportation or other sectors. High prices and resulting economic impacts were the major tools available. To see the impacts of the CO_2 price levels, two sensitivities were developed. In one (Low CO_2), CO_2 prices in all years were reduced by 20%. This demonstrated the effect of CO_2 costs over all years. In the other (Flat CO_2), the 2030 price was held constant from 2030 on. This just demonstrated the effect on the electric sector if those prices were not high in the later years. The MRN was not rerun for sensitivities, so economy-wide changes due to flat CO_2 prices were not examined.

For the two CO_2 futures, the Flat CO_2 sensitivity had only a small impact on generation in 2030 (Fig. 102) because CO_2 prices were the same up to that point. Capacity changes were similarly small by this point in time. By 2050 capacity and generation types and quantities differed greatly from the base scenario with its higher CO_2 prices, but results post-2030 were not a focus of this analysis. The Low CO_2 sensitivity resulted in more natural gas–fired generation and less generation by renewable sources, which would be expected with a decrease in CO_2 price. The base NUC future did not include a CO_2 price so coal generation was extensive in it. Adding the base CO_2 price curve to the NUC future created a large change in generation and capacity, with the practical elimination of coal and large increases in nuclear power and gas-fired and renewable generation. This sensitivity had by far the largest use of nuclear power of all of the cases in Phase 1, with 191 GW in place in 2030. Figure 103 shows the amount of nuclear capacity in those regions that had changes from the BAU future. Note that the Southeast had most of the growth in nuclear, both when going from the BAU to the NUC base and from the NUC base to the NUC CO_2 sensitivity. Florida (FRCC) had the most significant changes.

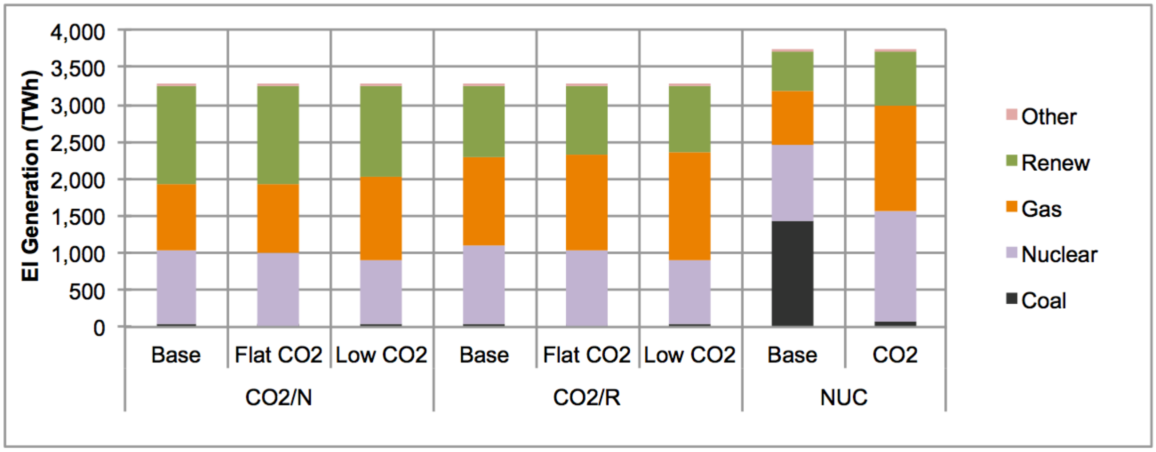


Fig. 102. Eastern Interconnection (EI) Generation in 2030 by technology for CO_2 price sensitivities.

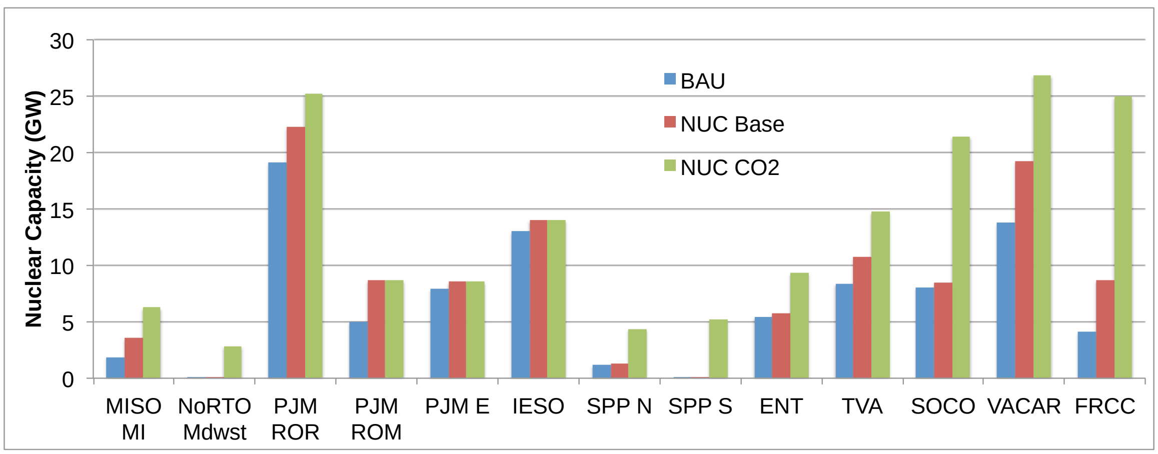


Fig. 103. Nuclear capacity in 2030 for the business as usual (BAU) and nuclear resurgence (NUC) futures and nuclear resurgence–carbon dioxide (NUC CO_2) sensitivity.

12.2 Delayed Implementation of Environmental Policies

The base cases of the different futures included the expected EPA air and water regulations affecting power plants, including the Transport Rule, Utility Mercury and Air Toxics Standards Rule, Utility New Source Performance Standards Rule, Coal Combustion Residuals Rule, and Cooling Water Intake Structures Rule. Also examined were the PTC and existing state RPS rules. While many of the sensitivities increased the attractiveness of renewables, five sensitivities were run in the BAU future that examined downgrading environmental policies through delays in implementation or removal entirely (Table 53).

Table 53. Generation by Technology in 2030 Under Different Delayed Environmental Policies (TWh)
(Base row shows generation amount while other rows show difference from base.)

Case	Description	Coal	Nuclear	Gas	Renew	Other
Base	Business as Usual	1,428	818	956	505	10
Reduce RPS/EE/DR requirements	Reduce existing state RPS by 5% in absolute terms within the time frame specified by each state's RPS requirement. Reduce EE/DR requirements (in states that have them) by 5 percentage points each by end of study period.	44	0	138	−53	−2
Delay EPA 5 years	Less-aggressive implementation of upcoming EPA regulations by delaying implementation 5-years	26	0	−26	0	0
Delay EPA	Delay implementation of new noncarbon EPA regulations beyond period of study	121	0	−117	−4	0
No PTC no RPS	No policies/regulations continued past current expiration (PTC/ITC, etc.); RPS requirements removed.	18	0	85	−104	0
No PTC No RPS High Load	No PTC/RPS plus high load growth.	30	0	842	−103	0

The first sensitivity listed reduced the RPS and EE/DR requirements that states currently have in place. Coal and gas generation increased while renewable generation decreased in response to these changes. Total generation increased by 3.4% due to the removal of EE requirements. Delaying implementation of the EPA rules by 5 years increased coal production relative to the base at the expense of gas-fired generation. Delaying implementation of the rules beyond 2030 increased coal generation even more, again at the expense of gas. Removing the PTCs once they expire and any RPS requirements shifts generation from renewable (−104 TWh) to gas (85 TWh) and coal (18 TWh). Most of the higher demand in the last sensitivity was met by gas-fired generation; coal use increased slightly.

12.3 More Stringent Environmental Policies

Most of the futures had some form of environmental policies in place, but sensitivities were added that increased the level of these policies. In the BAU future, the state-level EE and renewable energy requirements were raised by 5% each. The resulting generation in 2030 was reduced and also had an increase in renewable generation (Fig. 104). These both served to reduce the amount of gas-fired generation.

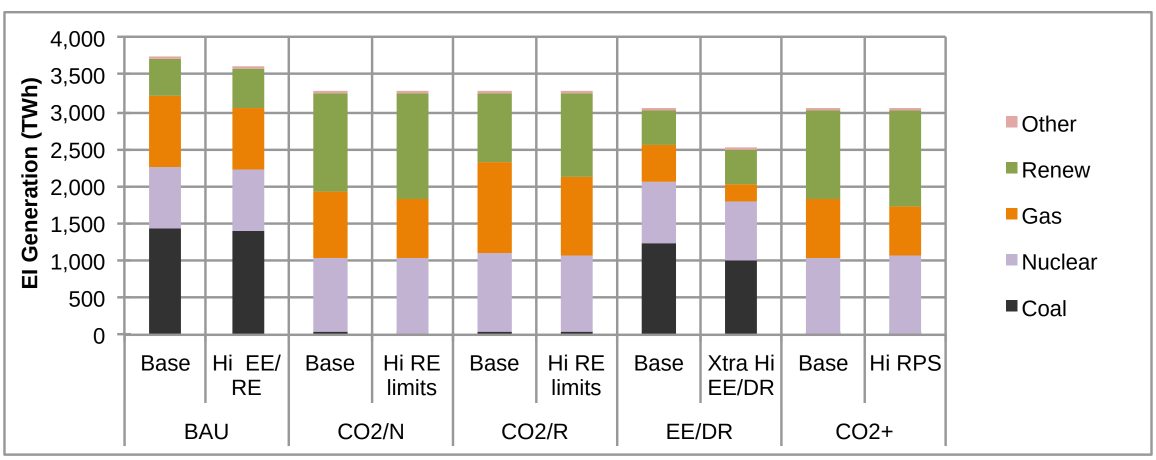


Fig. 104. Eastern Interconnection (EI) generation in 2030 by technology for increased environmental policy sensitivities.

In all futures, the base scenarios had a ceiling on the amount of variable generation (wind + solar) of 35% of the total generation. A sensitivity was run in the CO_2/N and CO_2/R futures that increased this limit to 50% of generation. This increased the EI's variable generation in the CO_2/N future from 30% to 33%. (The total is below the ceiling because the constraints were applied to groupings of regions such as the northeast, south, or central states. The ceiling could be binding in one region without reaching it in another.) Further, the ceilings were not reached until 2035 for CO_2/N (with its larger territories) but were reached by 2025 in the CO_2/R future.

The sensitivity in the CO_2+ future was similar. It raised the RPS from 30% to 40% and the variable generation limit to 40% as well. This increased the renewable generation from 39% to 43% of the total. Variable generation went from 28% to 31% of total demand in 2030.

The aggressive EE/DR future base case did not modify the RPS or CO_2 price, so renewables had a small proportion of total generation while coal remained significant. Rather, it increased the effect of EE by a 1% reduction in the annual demand growth rate along with an increase in the available DR for each region and a further reduction in demand through DG. The sensitivity within this future further increased the EE impact with an additional 1% reduction in growth rates and DR expansion beyond the full participation amounts reported in the FERC national assessment of DR (FERC 2009). The result of this sensitivity was a further decrease in coal- and gas-fired generation (Fig. 104).

12.4 Clean Energy Standard

An interesting variation on the RPS was the modeling of the federal administration's Clean Energy Standard (CES). The standard was a requirement on the ratio of qualified generation to total generation. It broadened the category of fuels that qualify for the standard from just renewables to all that lower or eliminate CO_2 emissions, including nuclear and gas-fired CC. The gas-fired generation was credited at only half of its generation since it still releases CO_2 but at about half the rate of coal-fired generation. The standard increased over time using the percentages in Table 54.

Table 54. Fraction of Electricity from Clean Sources by Year Required for the Clean Energy Standard

	2020	2025	2030	2035
Clean Energy Fraction	50%	60%	70%	80%

In the national implementation future (RPS/N), the standard was applied to all parts of the EI as a whole, while in the regional implementation (RPS/R), each region was expected to meet the standard. Some trading of credits between regions could alleviate that segregation however.

As can be seen in Fig. 105, the CES sensitivities dramatically reduce coal-fired generation as compared to the base scenario in each future. Gas-fired generation expands greatly, but generation from renewable sources does not grow as much as in the base. Figure 105, which includes the BAU future, also shows that even though the CES sensitivities do not have as much renewable generation as the base (with a 35% RPS), there is still much more than in the BAU. Furthermore, CO_2 emissions are dramatically less in the CES sensitivity than in the RPS base scenarios, as shown in Table 55. The base scenarios in the RPS futures only reduce CO_2 emissions by 24% from the BAU in 2030 while the CES sensitivities reduce it by 50%. The 2015–2030 CO_2 impacts are less because the early years have little change, but the difference grows over time.

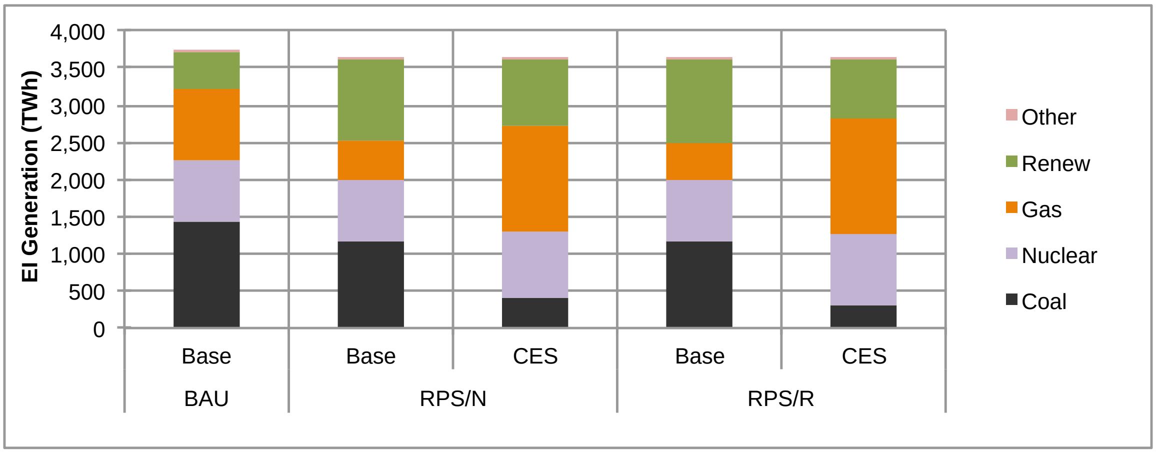


Fig. 105. Eastern Interconnection (EI) generation in 2030 by technology for Clean Energy Standard sensitivities.

Table 55. Carbon Dioxide Emissions (2015–2030 sum and 2030 alone) for Base and Clean Energy Standard (CES) Scenarios

	BAU	RPS/N		RPS/R	
	Base	Base	CES	Base	CES
EI 2015–2030 CO_2 Emissions (MMT)	26,031	23,272	20,697	23,012	19,791
EI 2030 CO_2 Emissions (MMT)	1,716	1,310	864	1,316	826

12.5 Conclusions

The high CO_2 prices in the three CO_2 futures greatly decarbonized the electric sector, especially post-2030. Lowering the CO_2 prices by 20% lowered the amount of renewable and nuclear capacity, with gas-fired capacity increasing. Of all policies, CO_2 price additions, in conjunction with other factors such as lowered capital cost, most incentivized nuclear capacity increases. Lowered nuclear costs by themselves had little effect on increasing nuclear share.

Reductions in stringency of or delays in implementing environmental policies generally increased the amount of coal-fired generation at the expense of gas-fired or renewable-source generation. Reducing current state RPS, EE, and DR goals allowed the increase of both coal- and gas-fired generation, with a smaller reduction in renewables such that overall demand increased. Simple delays in the current EPA requirements increased coal-fired generation at the expense of natural gas–fired generation, while elimination of the PTC and state RPS requirements lowered generation from renewable sources in favor of coal and gas, even with high load growth.

On the other hand, more stringent environmental policies generally reduced the amount of fossil fuel–fired generation through increases in EE, use of renewables, and/or DR. Lifting the original ceiling on variable generation from a maximum of 35% to 50% only increased total renewable amounts by 3%–4% because only the central and southwest regions could take advantage of this raised ceiling. Increasing the EE and DR programs resulted in lower fossil fuel–fired generation.

The CES program was intermediary between the base CO_2 and RPS cases. By setting a standard for all carbon-reducing technologies there was a significant reduction in coal-fired generation and carbon emissions without the impact of added CO_2 costs.

13. TOPIC 13: TECHNOLOGY SENSITIVITY IMPACTS

A number of the sensitivities involved changes to the various technologies (e.g., price, cost, efficiency, or availability). These were to explore the robustness of results under uncertainty as to how these technologies would perform in the future. Gas price sensitivities are included in this category because a main driver for projections of future gas prices is the continued feasibility of hydrofracturing technology and sufficient transportation infrastructure.

13.1 Gas Prices

The base gas prices followed a trajectory based on the reference case from the EIA's 2011 AEO (early release) (EIA 2011a). To explore the sensitivities of high and low gas prices, the SSC developed three other trajectories. The high gas price used the high gas case from the AEO 2010 (EIA 2010), with a composite between the two scenarios in the years before 2025. An extra high gas price trajectory that accelerated the rise in prices but was the same price as the high gas price trajectory by 2030 was also used. A low gas price trajectory was set at a flat $4.50/mmBtu. While these prices were the foundation for the modeling, they were adjusted in the inputs to reflect price differences between regions and between seasons. Figure 106 shows the price curves used for the base and sensitivities. It also shows the latest gas price forecast from the AEO 2014 (EIA 2014). The reference case in the AEO 2014 projects a price roughly $1/mmBtu lower than the EIPC study base but still higher than the study's low gas price sensitivity for most years.

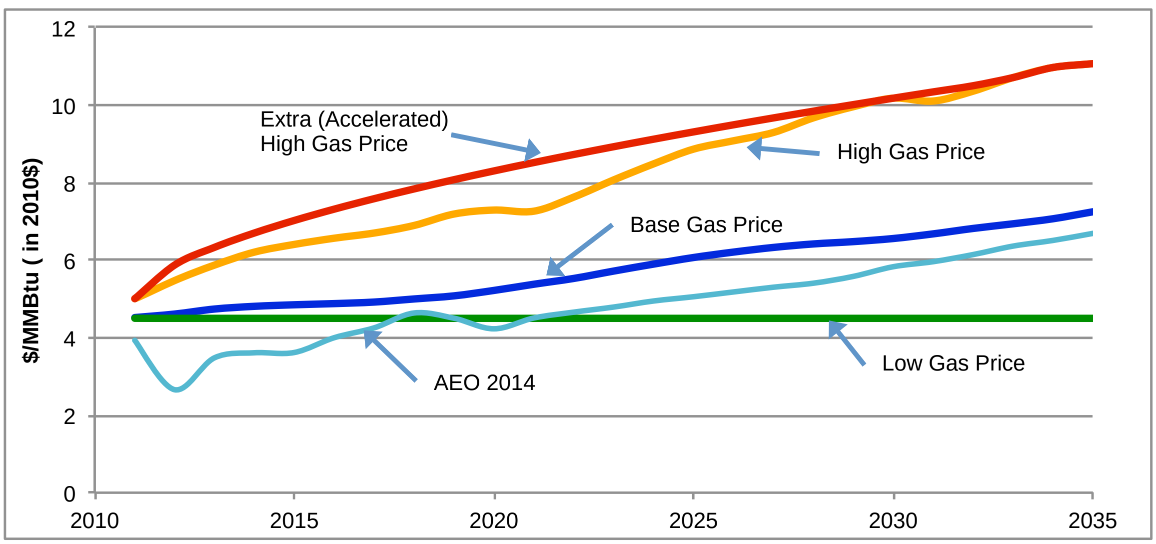


Fig. 106. Henry Hub gas price inputs to the MRN-NEEM model.

Five futures included gas price sensitivities. The BAU scenario included the high gas price and extra high gas price curves from Fig. 106 as sensitivities. The two CO_2 scenarios included the low gas price and extra high gas price curves as sensitivities, while the two RPS scenarios just used the high gas price sensitivity.

The generation shares in 2030 for each major technology group for the entire EI are shown in Fig. 107. In the BAU future with high gas prices coal retirements decrease and new coal and wind capacity is constructed. Fewer CC plants and CTs are constructed, and more steam oil/gas plants retire. With extra high gas prices, 2030 results are very similar to the high gas price sensitivity, as gas prices are the same by 2030.

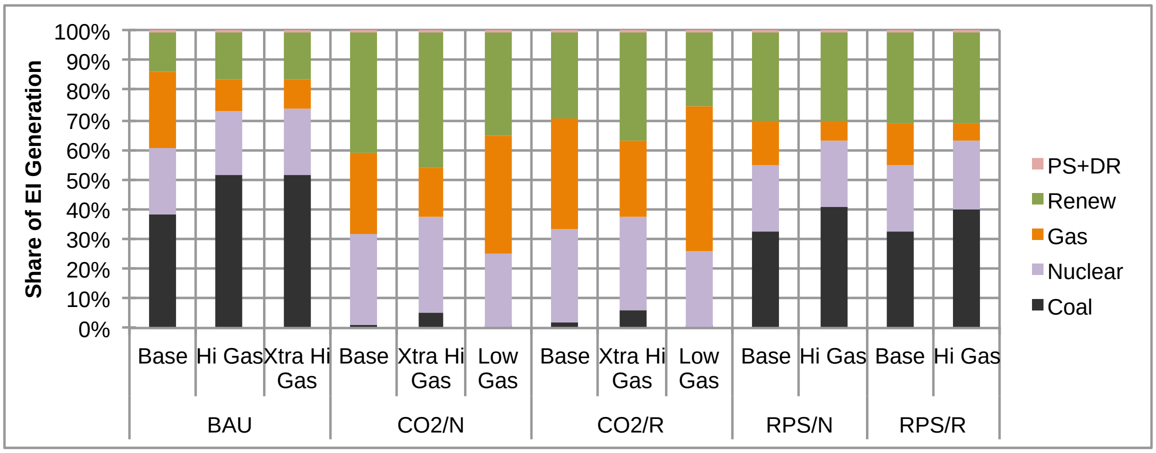


Fig. 107. Eastern Interconnection (EI) generation production share by technology for gas price sensitivities.

In the CO_2/N future, extra high gas prices lead to a 10% reduction in the gas-fired generation share (from 27% to 17%), with wind and coal making up most of the difference. The low gas price sensitivity had a 14% increase in the gas-fired generation share (from 27% to 40%), with reductions in renewable (6%), nuclear (6%), and coal-fired (1%) generation. Coal was reduced to almost no production.

In the CO_2/R future, extra high gas prices had about the same effect as in the CO_2/N future but started from a higher share, going from 37% to 26% of generation. Coal-fired generation increased 4% while renewables increased 7% to be 37% of generation. The low gas price sensitivity had gas-fired generation increase to 49% of generation, with nuclear going from 32% to 25%, renewables from 30% to 25%, and coal from 2% to 0%. The lack of transmission expansion meant that natural gas–fired generation was higher in the base case versus the CO_2/N future (see Chapter 2), and in the low gas price sensitivity, gas-fired generation had its highest market share of all cases.

In the RPS/N and RPS/R futures, the high gas price lowered the gas-fired generation share by 8%, with coal-fired generation replacing it. Because renewables were to meet the portfolio standard of 30%, they were only slightly affected by the gas price changes.

13.2 Renewable Technology Costs

The BAU future had a sensitivity that lowered the capital cost of renewables by 20% and one that lowered costs by 32.5%. The two CO_2 futures each had a sensitivity with the extra low costs for renewables, while the CO_2+ future ran the sensitivity with only a 20% reduction. These sensitivities were not included in the other futures because the SSC felt that lowered cost would not be a major driver for increased renewables or it was not the focus of the future.

As seen in Fig. 108, there is a small but noticeable increase in renewable generation with the lower costs. Table 56 provides more detail on the capacity levels for renewables in the different cases. Onshore wind makes up the bulk of renewables. A small amount of growth in offshore wind and hydro also occurs with the reduction in renewable costs. The biggest change is in the CO_2/R future, where the lower costs lead to large increases in offshore wind and other renewables. Since transmission is not available to transport onshore wind to coastal areas and the Southeast, offshore and other renewables become a cost-effective solution with high CO_2 costs.

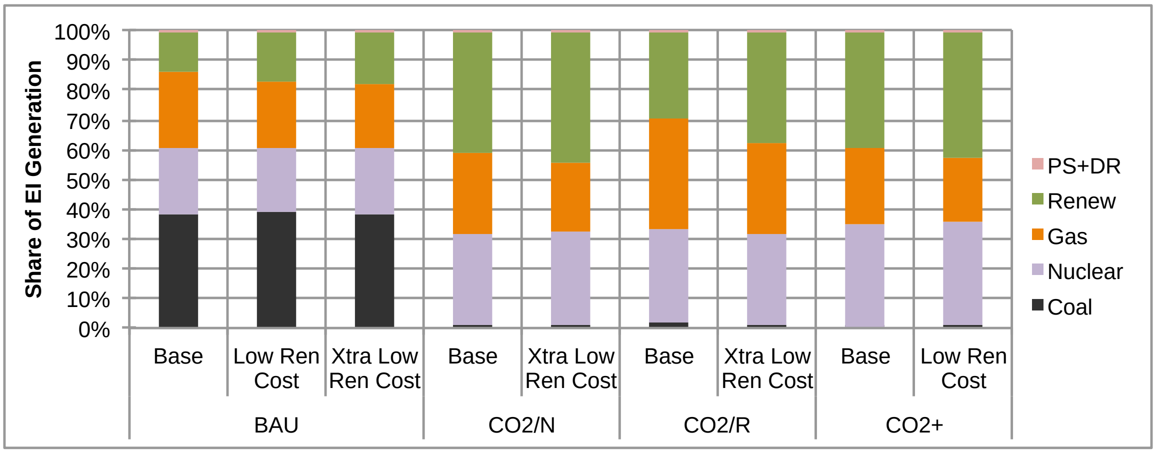


Fig. 108. Eastern Interconnection (EI) generation share by technology for renewable cost sensitivities.

Table 56. Renewable Capacities in 2030 (GW)

	Hydro	Onshore Wind	Offshore Wind	Other Renew	HQ/ Maritimes
BAU Base	45	68	2	16	9
BAU Low Renew Cost	45	108	4	15	9
BAU Extra Low Renew Cost	45	120	4	15	9
CO_2/N Base	51	317	2	16	12
CO_2/N Extra Low Renew Cost	52	357	3	15	12
CO_2/R Base	52	197	2	16	13
CO_2/R Extra Low Renew Cost	53	215	59	30	13
CO_2+ Base	50	261	2	15	14
CO_2+ Low Renew Cost	51	294	3	15	14

13.3 Plug-In Electric Vehicle Advances

The electricity demand from a small number of plug-in electric vehicles (PEVs) was built into the base demand assumptions because demand was largely from the EIA AEO 2011 that includes them. To explore the impact of a possible expansion of PEVs, the SSC increased the quantity of PEVs in 2030 by 10 times over that in the base, resulting in 25 million PEVs on the road in 2030. The expansion factor over the base grew over time, with 3 times in 2015, 6 times in 2020, and 9 times in 2025. Figure 109 is a chart of the PEV fleet size used in the analyses. The base case amount is from the AEO 2011 results, and the power demands are assumed to already be included in the base demands. Vehicle numbers are adjusted to reflect the quantity in the EI, including Canada. The base has 2.5 million vehicles by 2030, while under high growth the total is 24.6. So the high growth sensitivity includes an additional 22.1 million PEVs.

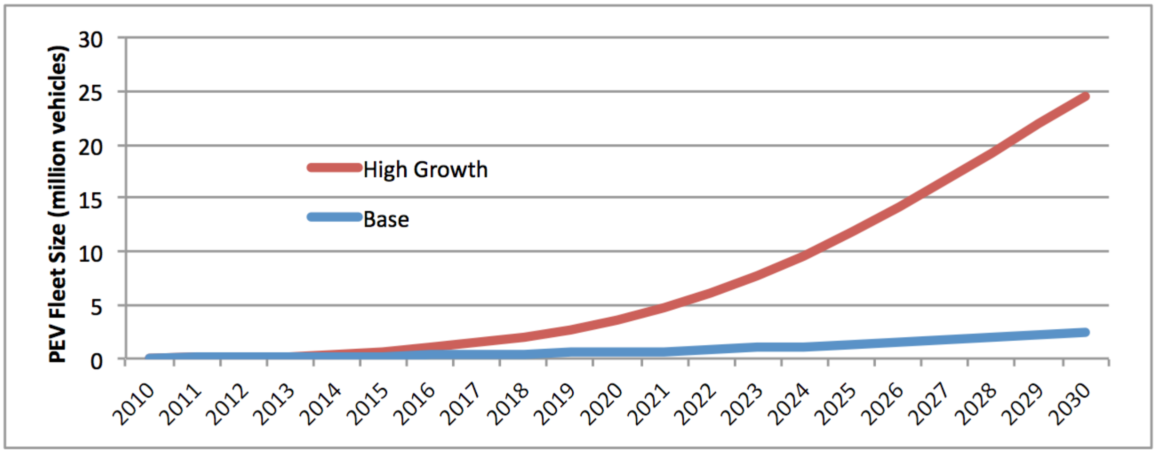


Fig. 109. Projected plug-in electric vehicle (PEV) quantities in the Eastern Interconnection.

The timing of PEV battery charging can have a major impact on the amount and type of capacity needed on the grid. If drivers charge their cars during the early evening when they return home, they will be using capacity at peak times. If they wait until later at night, the demand can be met during off-peak times when there is spare capacity. Two demand profiles were developed for vehicles, using a mixture of daily charging schedules and power levels based on an ORNL study (Sikes, et al. 2010). Figure 110 shows the load curves over 2 days when 10% begin charging between 5:00 p.m. and 7:00 p.m. (night) and when 50% begin charging during those times (peaking).

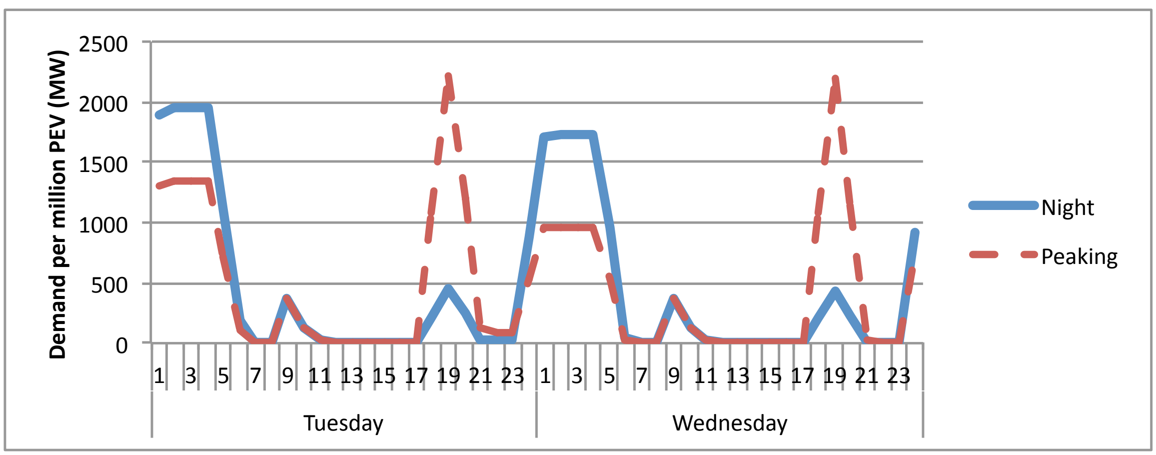


Fig. 110. Hourly demands from 1 million plug-in electric vehicles (PEVs) under the night and peaking demand cycles.

These were applied to the vehicles in each region to create demand profiles for each year. Because the base amounts were already included in system demands, just the demands from the additional vehicles were added to the system demands. The consequence of the two demand schedules can be seen in Fig. 111. If charging at nighttime using a smart grid, the impact on peak demands is only 5 GW. In the peaking scenario, 50% of vehicles begin charging upon return home between 5:00 p.m. and 7:00 p.m., and demand during the system peak is 27 GW by 2030. Translating into average capacity per vehicle, the night-dominant charging raises peak demand by just 0.1 kW/vehicle, while the peaking-dominant charging raises system peaks by 1.2 kW/vehicle.

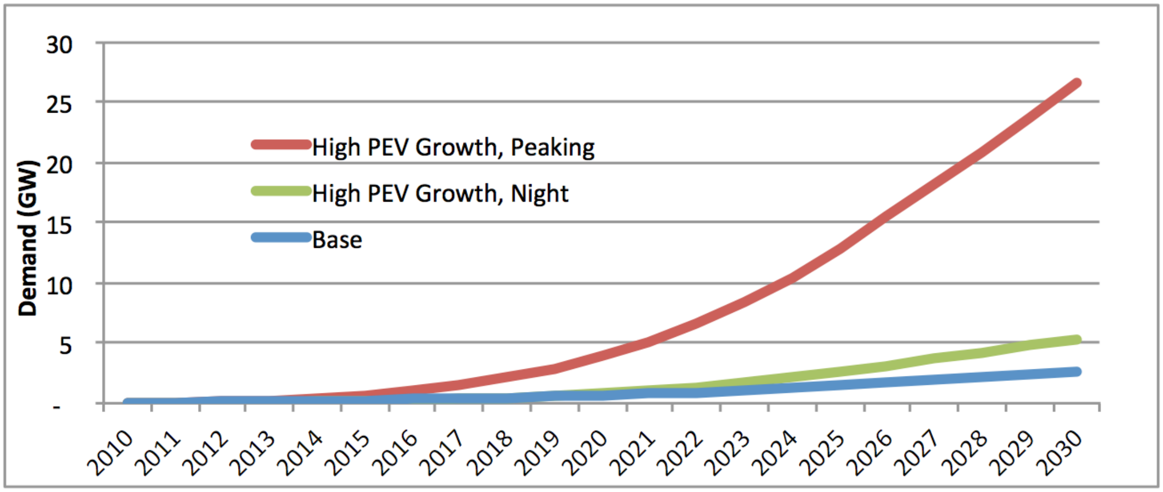


Fig. 111. Peak demand increases in the Eastern Interconnection due to base and high plug-in electric vehicle (PEV) growth.

Increased PEV market sensitivities were included in the BAU, EE/DR, RPS/N, and RPS/R futures. In all of the futures, adding PEVs increased the total generation for the EI by about 77 TWh (Fig. 112), or 3.5 MWh/vehicle. The BAU, RPS/N, and RPS/R futures all modeled just the peaking PEV charging behavior, while the EE/DR future had sensitivities for both the peaking and the night (smart grid) PEV charging. Figure 112 identifies the marginal generation used to meet the PEV demands. For the BAU future, added demand for PEV charging was almost totally provided by natural gas–fired generation, either CC or CT. The EE/DR future included coal as a marginal provider because demands were low enough that some charging was during periods when coal capacity was available. Note that in Fig. 113 the capacity added for the PEV night charging sensitivity is significantly less than that for the peak charging sensitivity. Gas-fired capacity was actually less than the base case despite the increase in demand. The RPS futures had coal, gas, and renewables as marginal providers because, as shown in Fig. 113, renewable capacity was added in the PEV charging sensitivity over and above what was added in the base RPS futures.

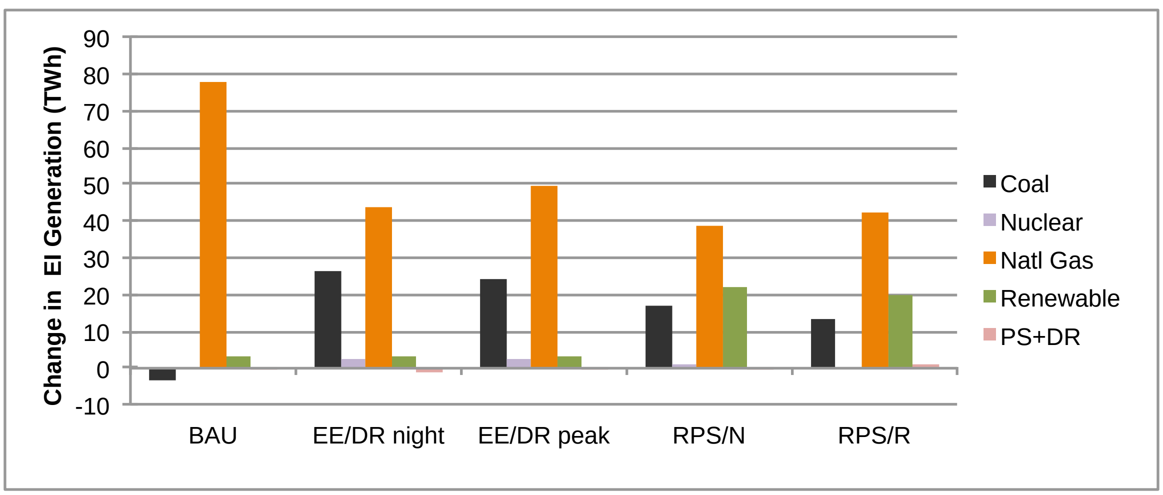


Fig. 112. Changes in Eastern Interconnection (EI) generation between the base scenario (BAU) and plug-in electric vehicle (PEV) sensitivity for three futures. The energy efficiency/demand response (EE/DR) future had two sensitivities: one with more PEV charging at peak times and one with charging at night (off-peak).

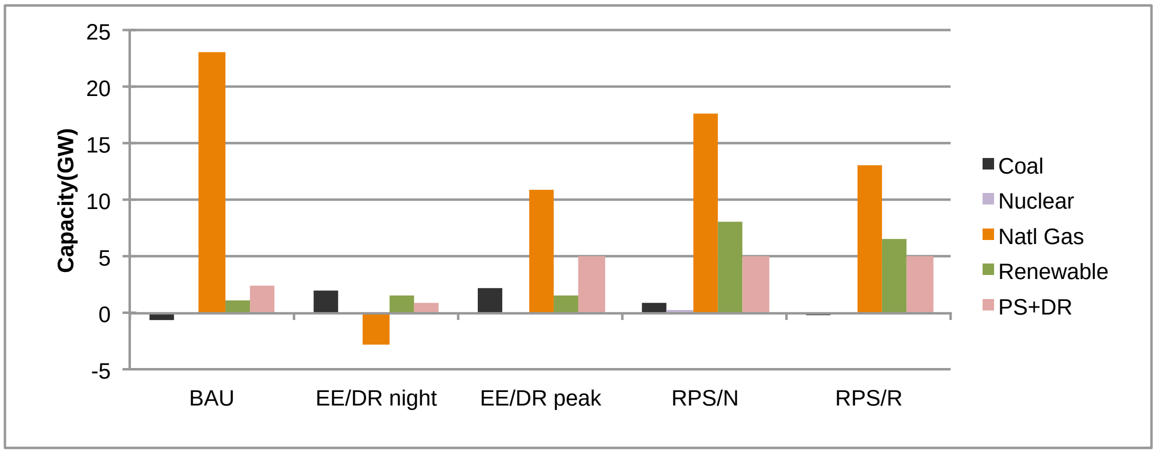


Fig. 113. Capacity changes between the base scenario (BAU) and plug-in electric vehicle (PEV) sensitivity for three futures. The energy efficiency/demand response (EE/DR) future had two sensitivities: one with more PEV charging at peak times and one with charging at night (off-peak).

13.4 Small Modular Reactors

The NUC future was used to examine the possible effect of policies and technologies that might increase the use of nuclear power in the EI. One sensitivity examined the effect of increasing the availability of small modular reactors (SMRs) as a viable alternative to large nuclear plants. The mechanism to model the difference was to decrease the capital cost between 2011 and 2025 by 15% instead of 10% in addition to using the 20% reduction in nuclear capital cost as in the base NUC future. The overnight capital costs used in the other futures, the NUC base, and the SMR cases are shown in Table 57.

Table 57. Nuclear Capital Costs[a]

	AEO: Base Overnight Costs in 2011	Learning by 2025	Base Overnight Capital Costs in 2025	Other Overnight Capital Costs	All-in Capital Cost in 2025 w/o IDC
Base	5,339	10%	4,805	276	5,081
Nuclear resurgence (20% reduction)	4,271	10%	3,844	276	4,120
Small modular reactors	4,271	15%	3,631	276	3,906

[a] All costs are in 2010 dollars per kilowatt.

Despite the lower capital cost, there is no change in the nuclear capacity built between the nuclear resurgence base and the SMR sensitivity through 2030. There is a $2 billion levelized cost saving from 2015 to 2030 for the SMR sensitivity but this is less than 0.1% of total costs. The savings reflect both the lowered capital cost of new nuclear plants built in the cases and minor variations from modeling.

13.5 Offshore Wind

The base case for all scenarios except RPS/R included 1,569 MW of offshore wind forced into the model: 1,100 MW in PJM E, 468 MW in NEISO, and 1 MW in VACAR. In these futures the offshore wind capacity increased in the sensitivities with lower renewable costs. In the CO_2/R with extra high gas prices, the combination of the two cost changes also led to some increase. The RPS/R future showed increased capacities in all cases except the CES sensitivity because it allowed a broader range of technologies to qualify for the standard. Table 58 lists the different scenarios with the amount of offshore wind capacity in 2030 by region. The main regions that expanded resources were VACAR (the Carolinas), and PJM E

(New Jersey). The model added some capacity in PJM ROM (Maryland and Delaware) in a couple of sensitivities once VACAR and PJM E had reached their capacities. All other additions were input into the model by the SSC to reflect expected additions under different scenarios.

Table 58. Offshore Wind Capacity in 2030 for Different Sensitivities (MW)

	MISO MI	PJM ROR	PJM ROM	PJM E	NYISO J-K	NEISO	VACAR	Total
BAU, CO_2, EE/DR, RPS/N, CO_2+ Base (plus all other sensitivities not listed)	-	-		1,100	-	468	1	1,569
BAU Extra Low Renewable Cost	-	-	-	1,100	-	468	2,672	4,240
BAU Low Renewable Resources Cost	-	-	-	1,100	-	468	2,654	4,222
CO_2/N Extra Low Renewable Costs	-	-	-	1,100	-	468	1,155	2,723
CO_2/R Extra high natural gas price	-	-	-	1,100	-	468	8,073	9,641
CO_2/R Extra Low Renewable Costs	-	-	10,010	9,600	-	468	39,250	59,328
RPS/N High Offshore Wind	250	2,125	-	5,624	4,500	5,968	2,000	20,467
RPS/R Base	-	-	-	9,453	-	468	28,546	38,467
RPS/R High Load Growth	-	-	1,976	9,600	-	468	39,250	51,294
RPS/R High Natural Gas Price	-	-	-	9,600	-	468	28,890	38,958
RPS/R Higher Canada Hydro	-	-	-	9,453	-	468	28,886	38,807
RPS/R Higher PEV Levels	-	-	-	9,600	-	468	29,026	39,094
RPS/R High Offshore Wind	250	2,125	-	9,453	4,500	5,968	28,764	51,060
CO_2+ Low Renewable Cost	-	-	-	1,100	-	468	1,081	2,649

13.6 Conclusions

The base case of each future resulted in generally different mixes of generation. Changing gas prices within each future had the expected effect: lower prices led to increased gas use while higher gas prices reduced the gas-fired capacity and generation. Similarly, renewable capital cost reductions result in increases in renewable capacity. Onshore wind is the main beneficiary of the lower costs, though in the CO_2/R future, the lower costs also increase the offshore wind, PV, and hydro capacities.

PEVs could raise peak demands and consequent capacity requirements, with the impact strongly depending on the timing of the charging. If charging is prominently at peak times, then the system peak increases by 1.2 kW/vehicle. If charging is delayed to nighttime (such as through smart grid implementation), then the peak only increases by 0.1 kW/vehicle. Marginal generation to meet the added demand comes from natural gas, with some coal and renewables under the RPS futures.

Offshore wind capacity could be selected in all cases but was only selected in sensitivities with lower renewable capital costs or in the RPS future with regional response (RPS/R). In this study, the preferred location for offshore wind was in VACAR, followed by PJM E, and then PJM ROM. Other regions had offshore wind forced in, but capacity did not grow beyond the input amounts.

14. TOPIC 14: CHANGE IN KEY INPUTS BETWEEN 2011 AND 2014

The input assumptions used in the EIPC study were 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 topic 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. [Note that changes in gas prices since the time of the EIPC study are discussed under Topic 13 (Chapter 13).]

14.1 Capital Costs

The capital costs of new generation resources such as CTs, CC facilities, and wind power facilities are a key determinant in the type of new generation that will be constructed in the model. 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 EIA's AEO 2011 (EIA 2011b). Because of this, updated EIA capital costs were obtained from AEO 2014 (EIA 2014), and the comparison to the EIPC study assumptions is provided in Table 59. Also shown are the cumulative additions by 2030 for each capacity type in each of the three EIPC Phase 2 futures.

Table 59. 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 59 would not have had much impact.

One key change is in the projected capital cost of 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.

14.2 Distributed Solar

14.2.1 Distributed Solar Modeling

Generator modeling in the MRN-NEEM model focused on central station facilities rather than end-user-owned DG. To model the accelerated acceptance of DG for the EE/DR/DG and CO_2+ futures, the SSC 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 AEO 2011 early reference case (EIA 2011a). 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 114 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 NEEM regions. The AEO 2011 reports the amounts for each of the 22 regions used in its model, called Electricity Market Module regions. 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 disaggreation 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 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.

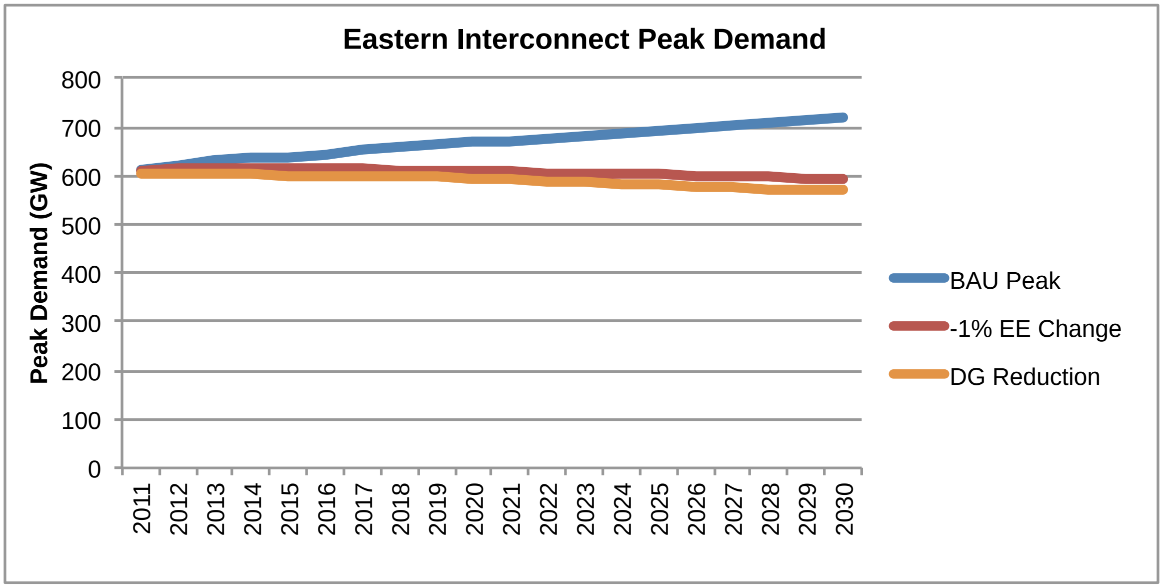


Fig. 114. Eastern Interconnection peak demand in the BAU and EE/DR/DG (and CO_2+) futures before and after DG reductions.

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.

14.2.2 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 60. 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 60. 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.

14.3 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 115 and Table 61 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).

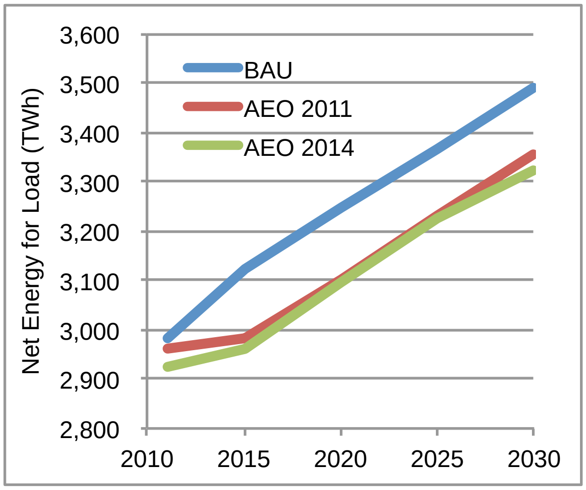


Fig. 115. Energy demand in the US EI regions from the BAU and AEO reference cases.

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 61.) 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 61. 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%

14.4 Environmental Policies

14.4.1 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 62 lists the EPA rules that were included in the EIPC analysis and summarizes their current status.

Table 62. 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.

14.4.2 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 63 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.

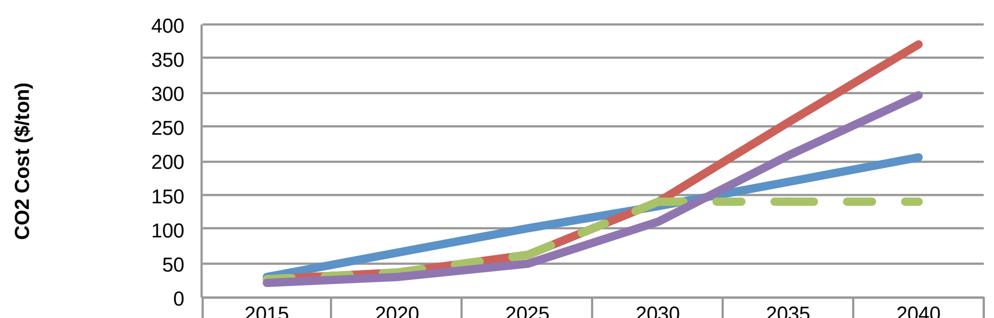
Table 63. Modifications to State Renewable Portfolio Standards

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

14.4.3 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 116 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

Fig. 116. 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 117 shows the CO_2 emissions reductions at the EI level for the BAU and various sensitivities that produce significant CO_2 emissions reductions.

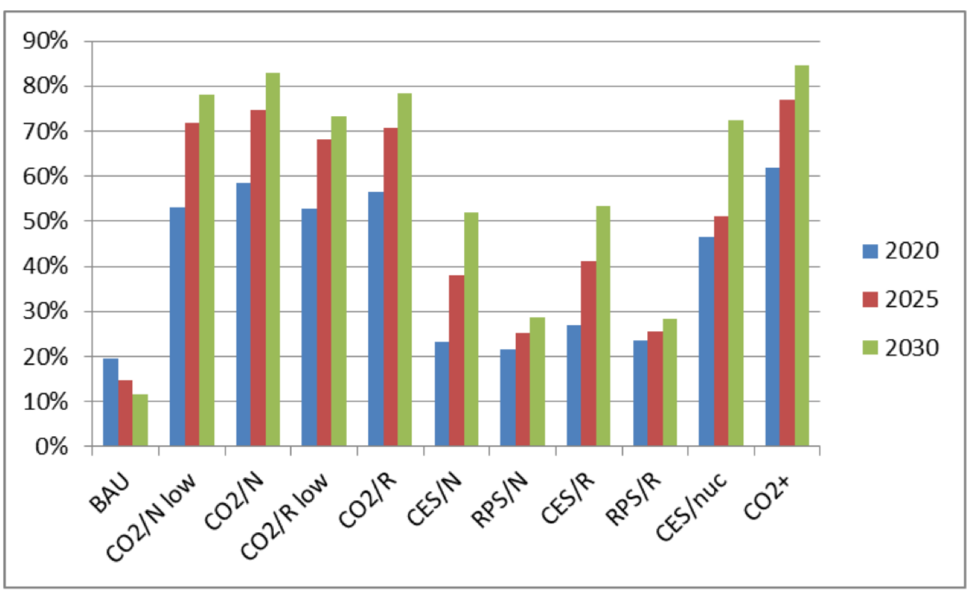


Fig. 117. Carbon dioxide emissions reductions relative to 2005 levels for the BAU scenario and various sensitivities.

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 Fig. 118 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.

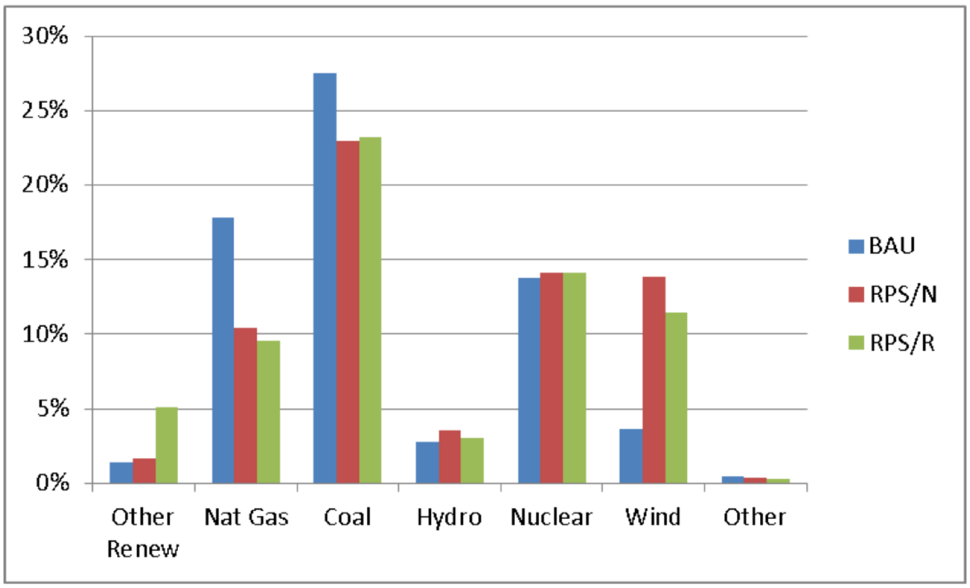


Fig. 118. Eastern Interconnection electricity generation sources under the BAU and RPS sensitivities in 2030.

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 Fig. 119, 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 120 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.

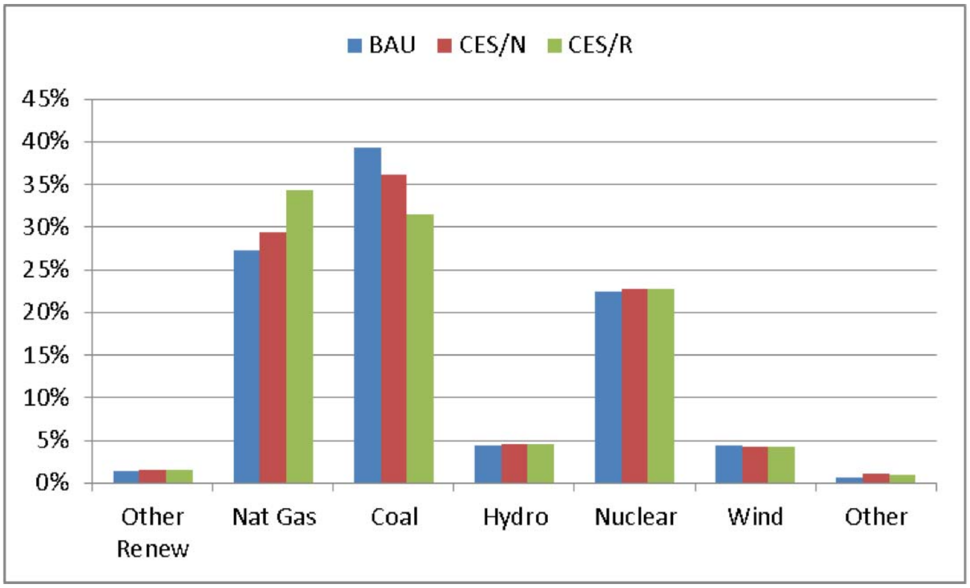


Fig. 119. Eastern Interconnection electricity generation sources under the BAU and CES sensitivities in 2020.

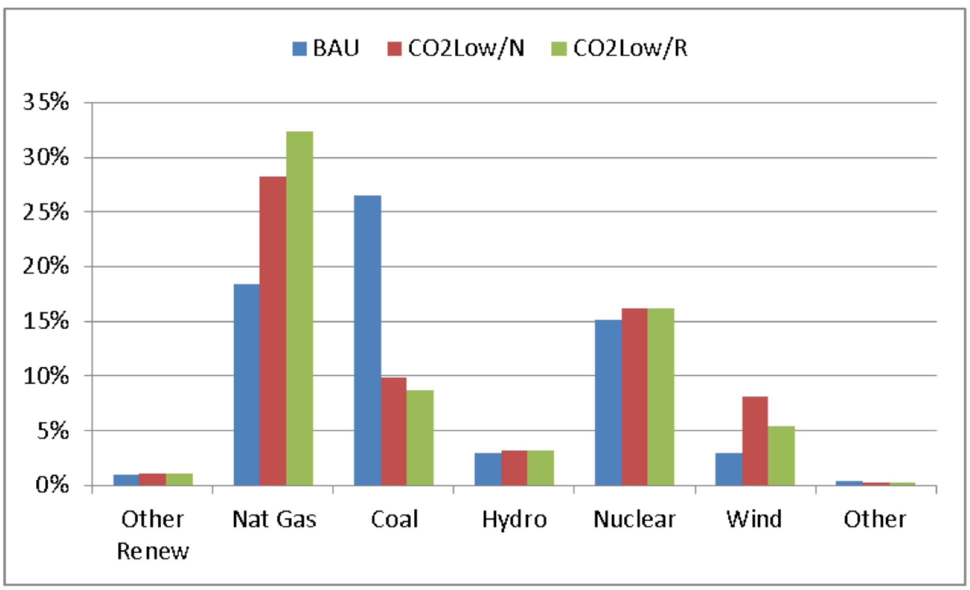


Fig. 120. Eastern Interconnection electricity generation sources under the BAU and CO_2 low sensitivities in 2020.

As was seen in the discussion of Topic 11 (Chapter 11), 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. Figures 121-123 show the ratio of CO_2 emissions levels in 2030 to the 2005 amounts for the two implementation strategies by NEEM region.

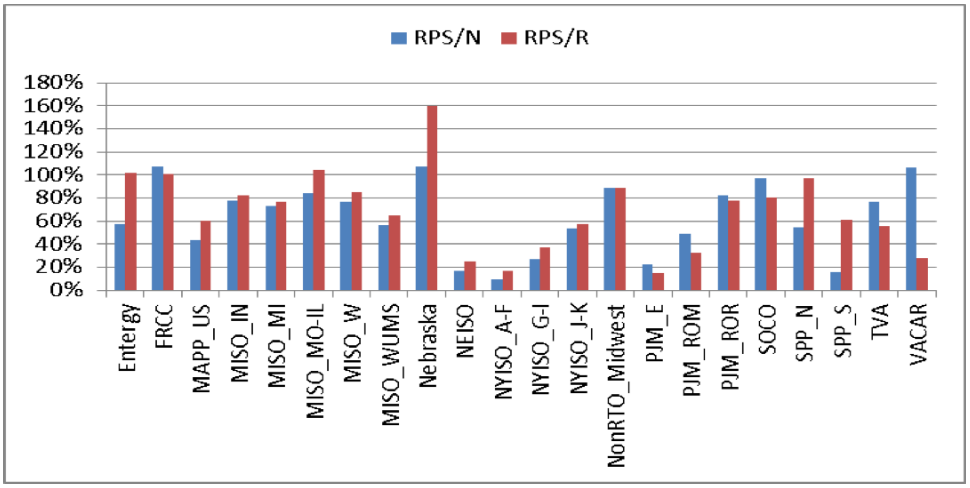


Fig. 121. 2030 CO_2 emissions levels relative to 2005 by NEEM region under RPS.

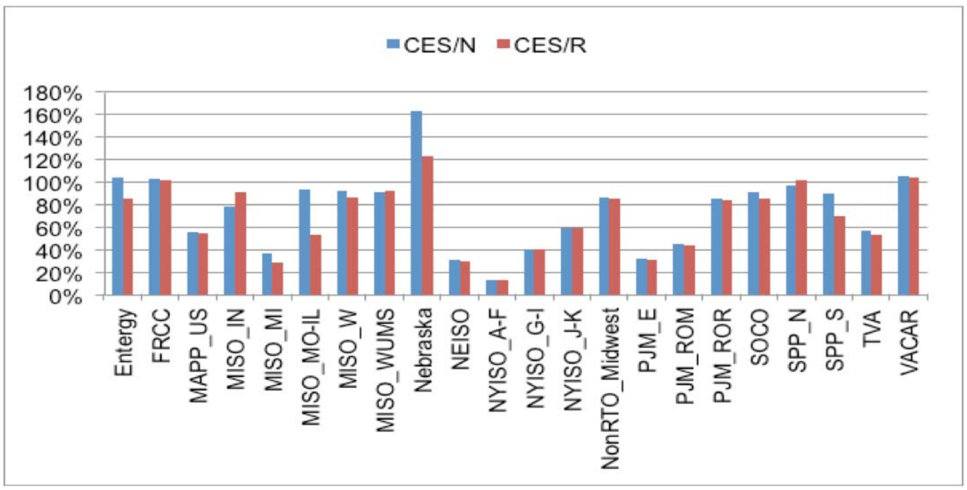


Fig. 122. 2020 CO_2 emissions levels relative to 2005 by NEEM region under CES.

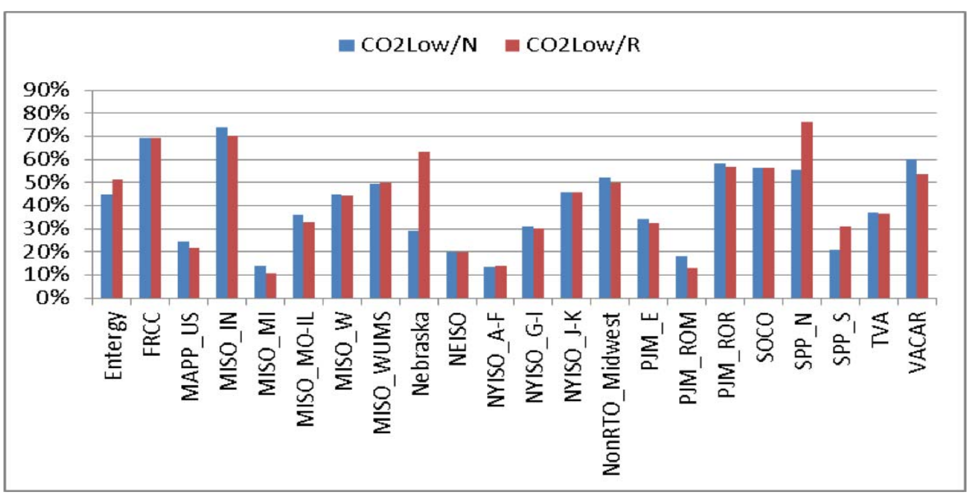


Fig. 123. 2020 CO_2 emissions levels relative to 2005 by NEEM region under low CO_2 prices.

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.

14.5 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.

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EIPC data documents on their website:

- Phase 1 Modeling Results: http://www.eipconline.com/Modeling_Results.html.
- Phase II Modeling Inputs: http://www.eipconline.com/Modeling_Inputs.html.
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APPENDIX A. COST, CAPACITY, AND GENERATION BY REGION

EASTERN INTERCONNECTION

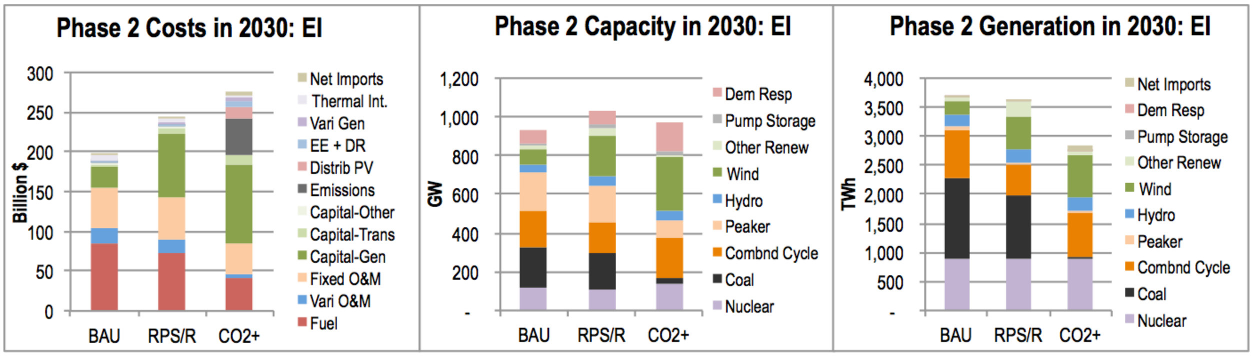

Fig. A-1. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Eastern Interconnection

NORTHWEST TERRITORY

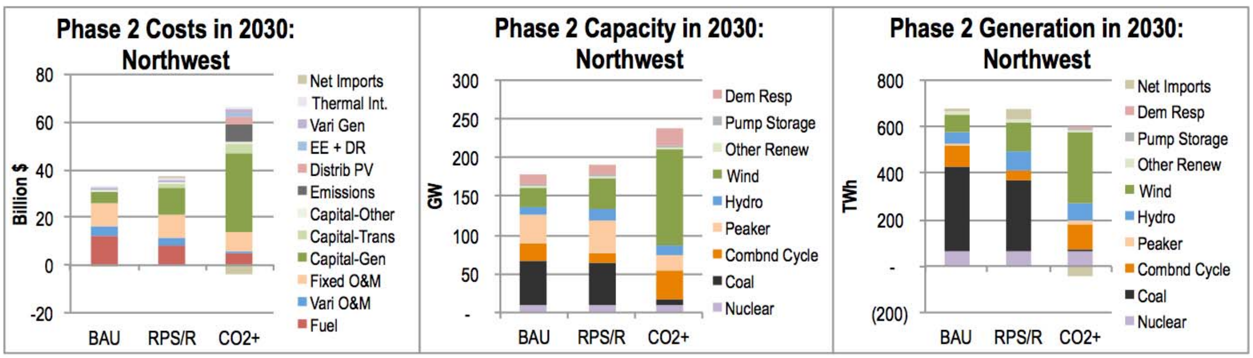

Fig. A-2. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Northwest territory

Regions

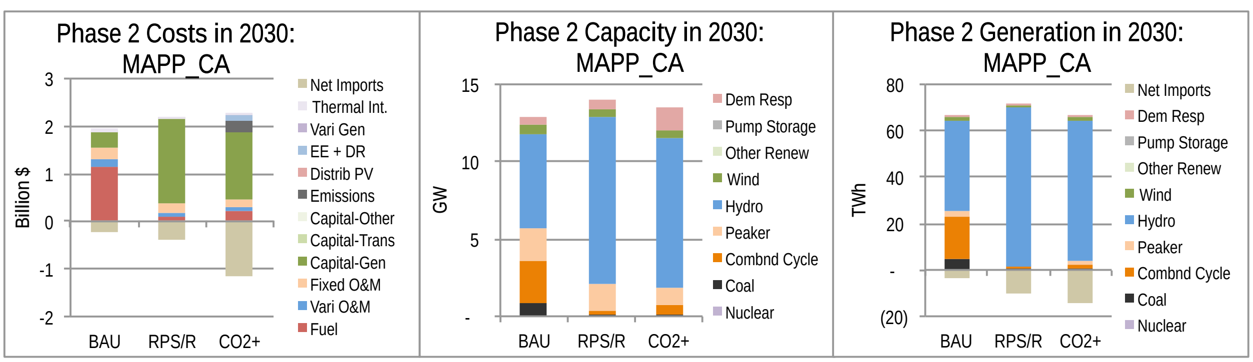

Fig. A-3. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MAPP CA region

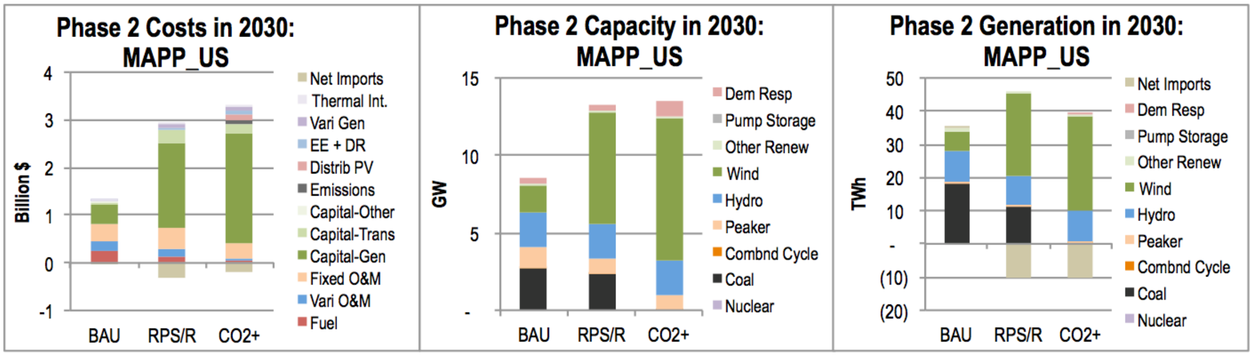

Fig. A-4. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MAPP US region

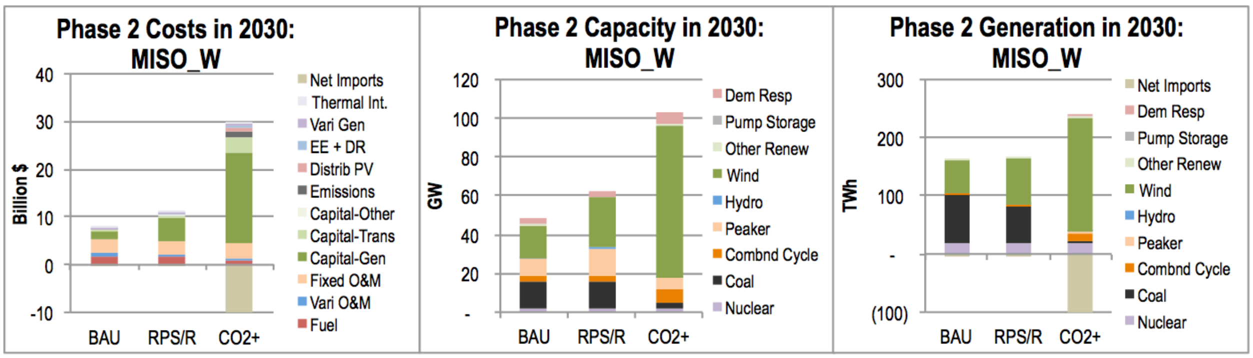

Fig. A-5. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MISO W region

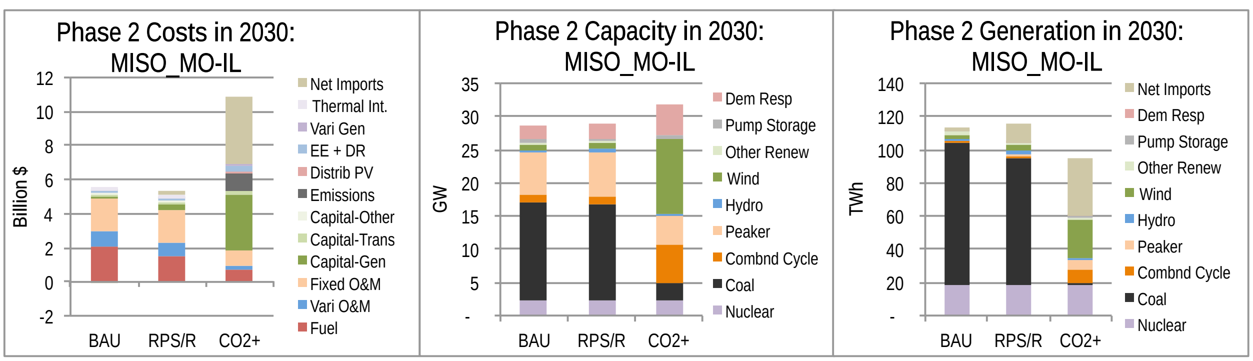

Fig. A-6. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MISO MO-IL region

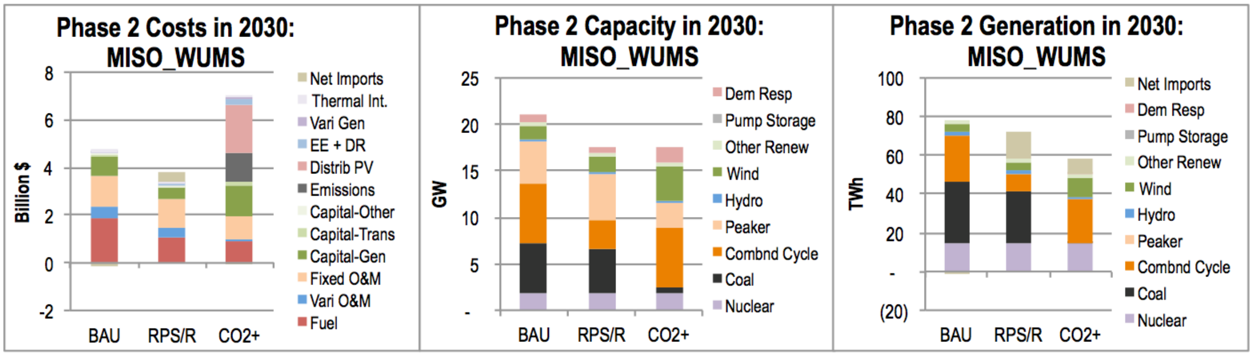

Fig. A-7. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MISO WUMS region

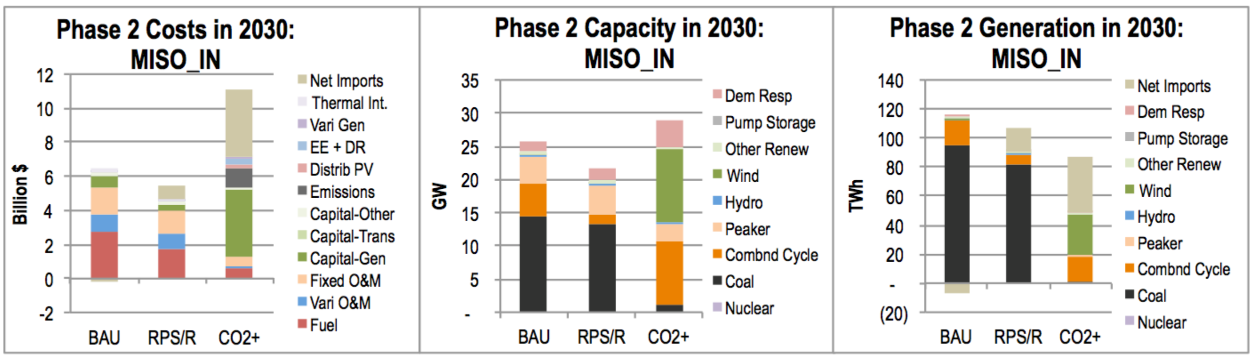

Fig. A-8. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MISO IN region

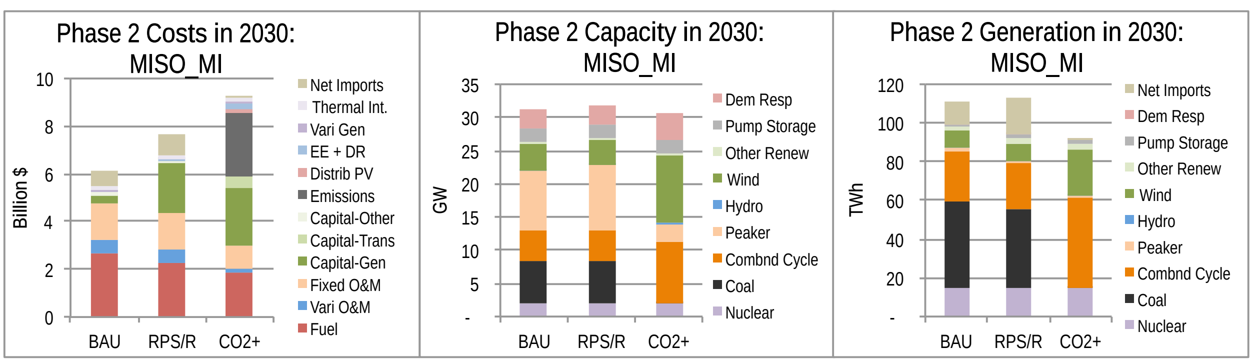

Fig. A-9. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the MISO MI region

CENTRAL TERRITORY

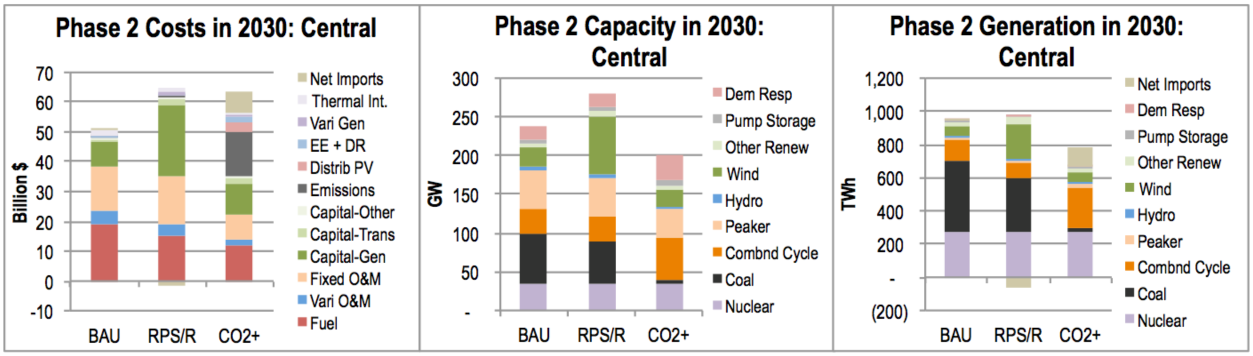

Fig. A-10. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Central territory

Regions

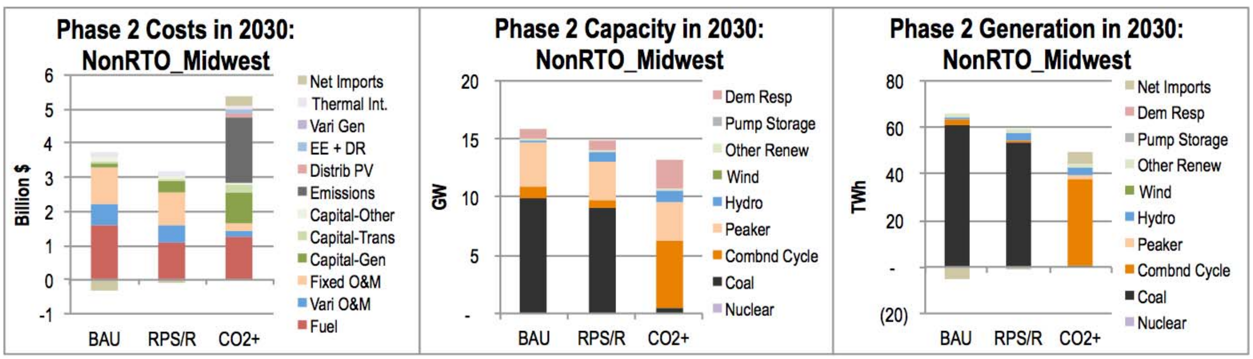

Fig. A-11. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Non-RTO Midwest region

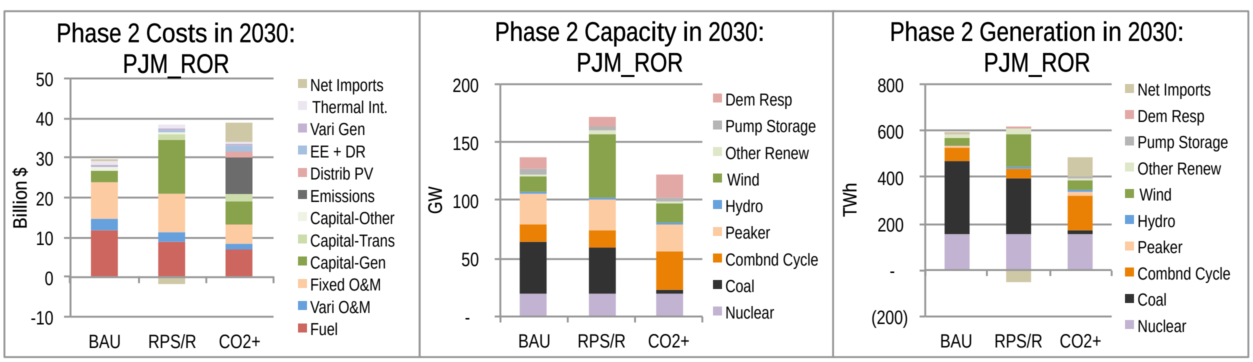

Fig. A-12. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the PJM ROR region

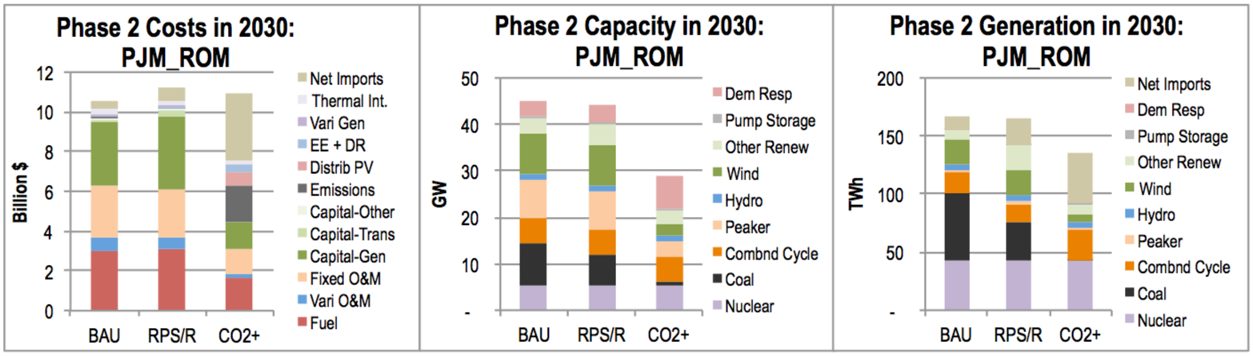

Fig. A-13. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the PJM ROM region

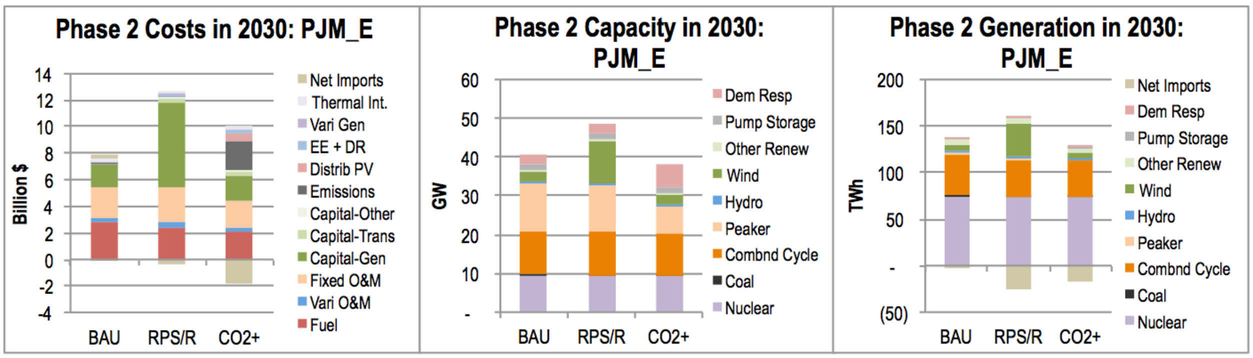

Fig. A-14. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the PJM E region

NORTHEAST TERRITORY

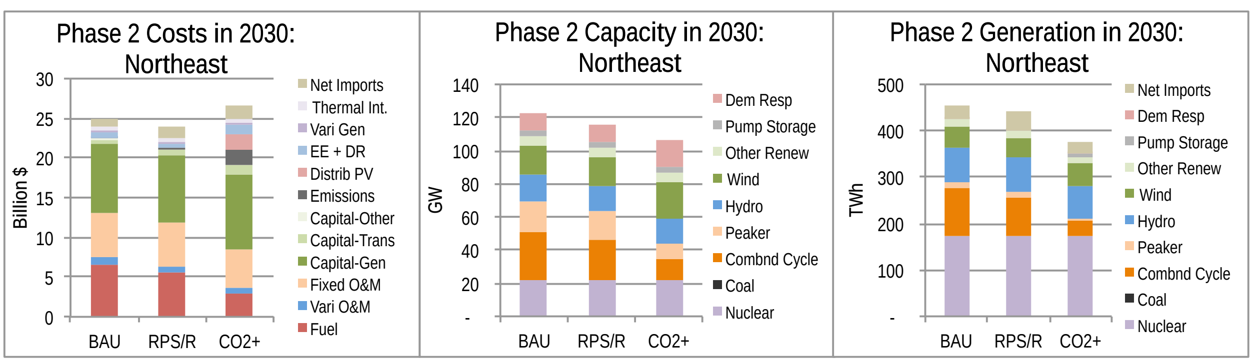

Fig. A-15. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Northeast territory

Regions

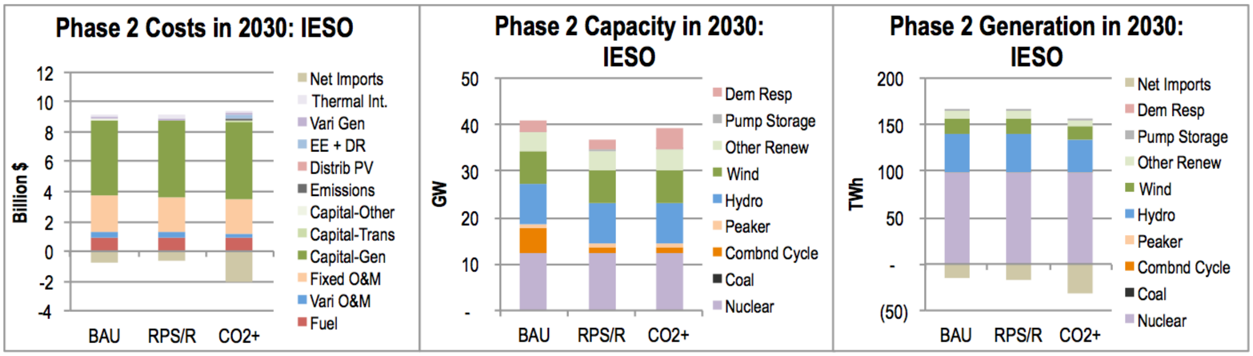

Fig. A-16. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the IESO region

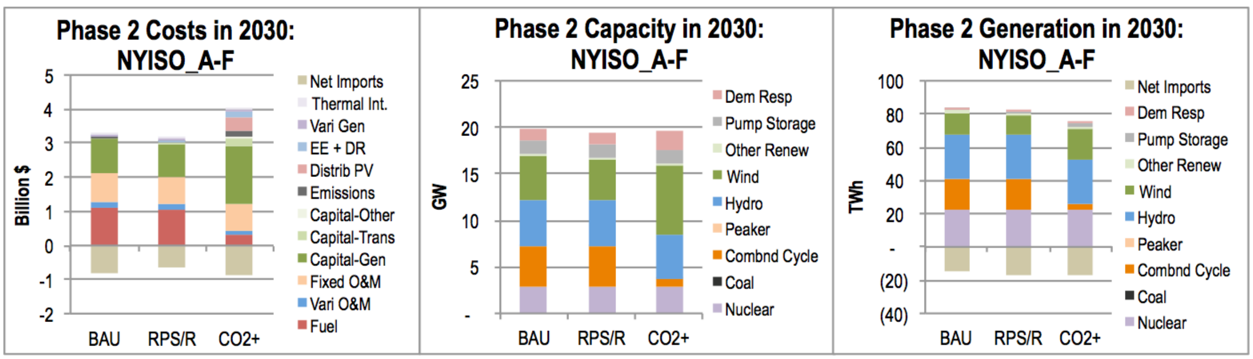

Fig. A-17. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the NYISO A-F region

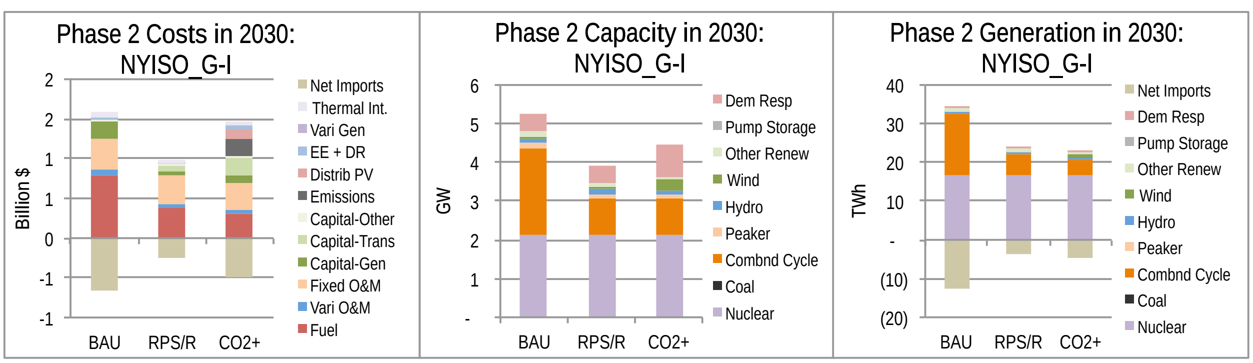

Fig. A-18. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the NYISO G-I region

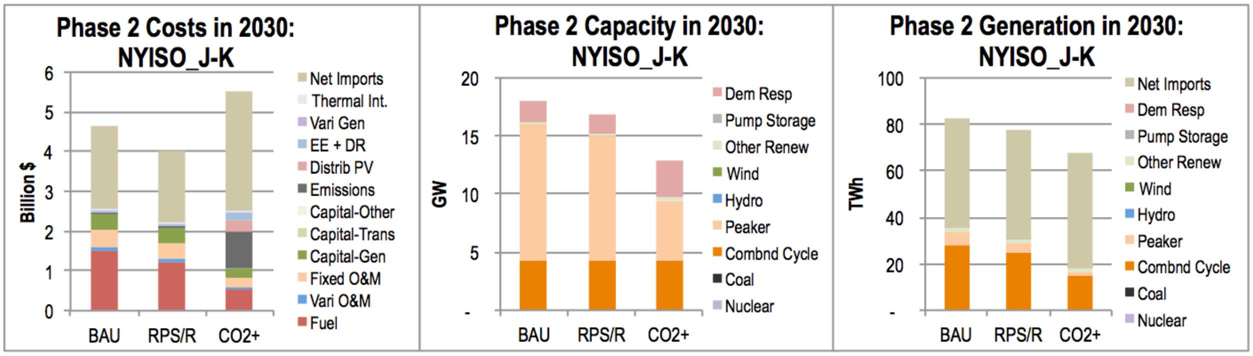

Fig. A-19. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the NYISO J-K region

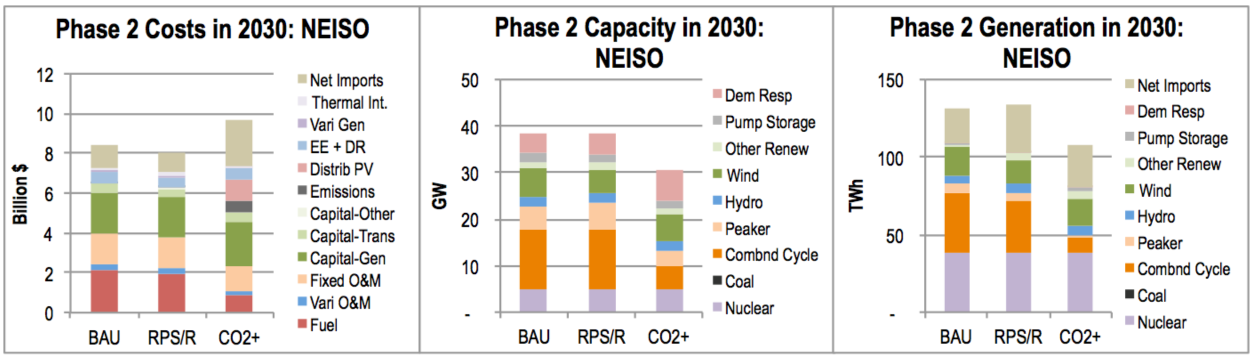

Fig. A-20. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the NEISO region

SOUTHWEST TERRITORY

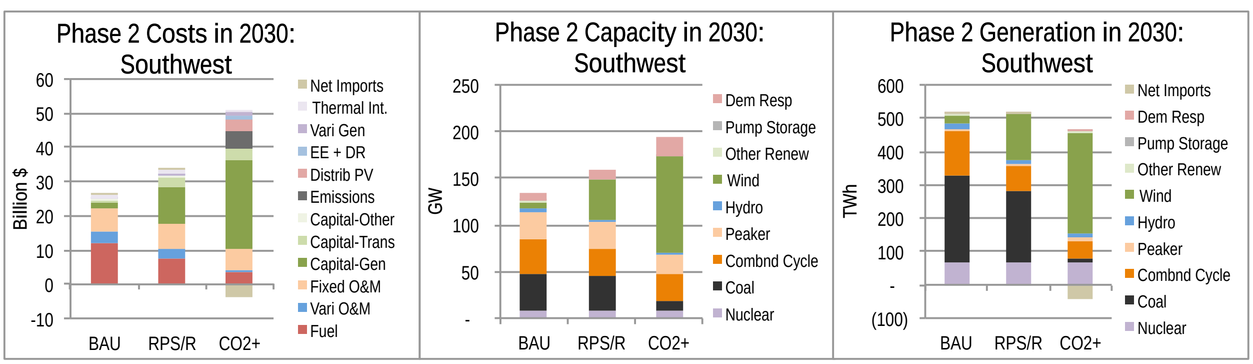

Fig. A-21. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Southwest territory

Regions

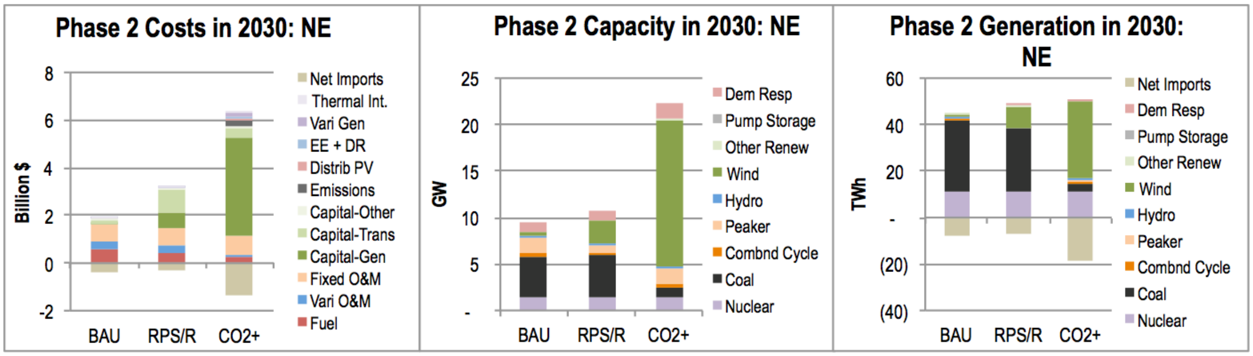

Fig. A-22. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Nebraska region

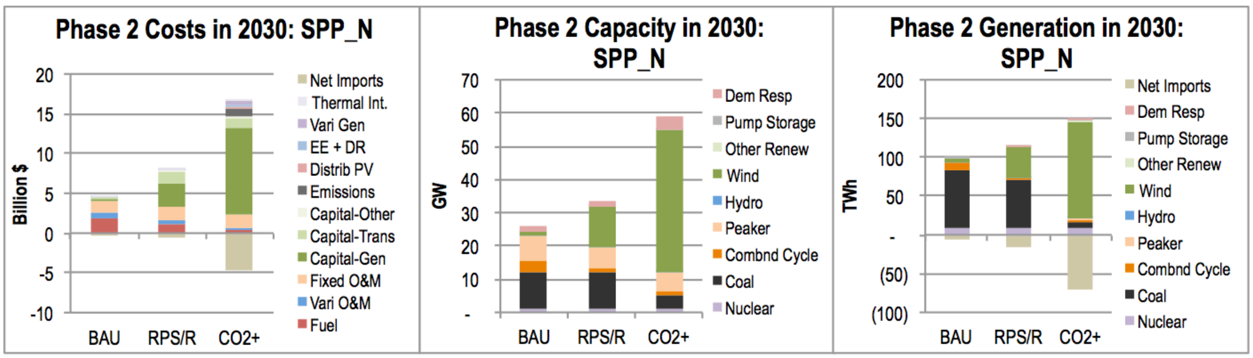

Fig. A-23. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the SPP North region

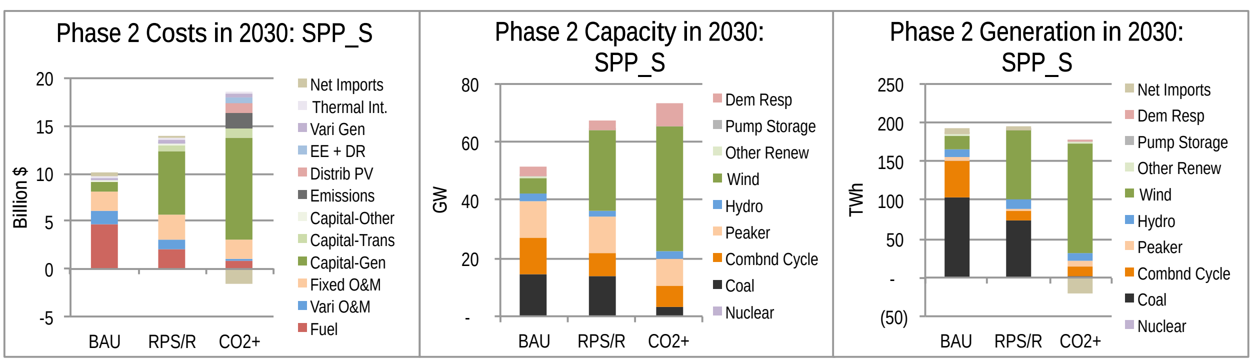

Fig. A-24. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the SPP South region

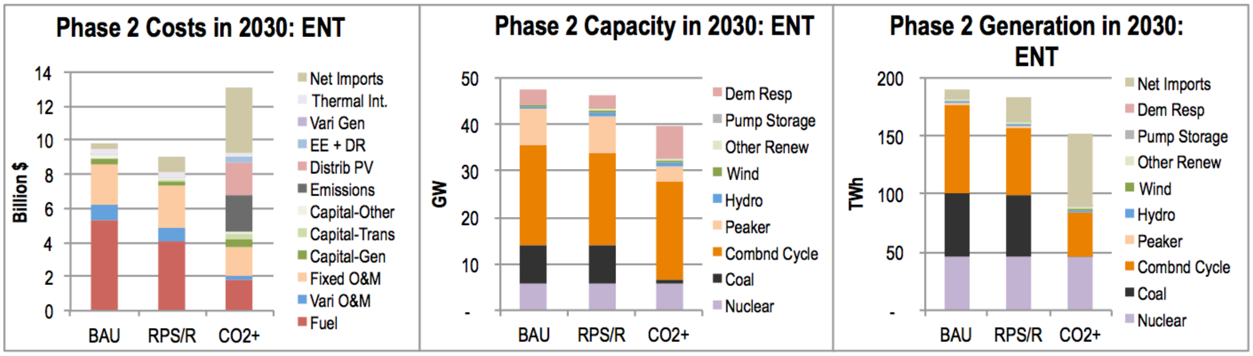

Fig. A-25. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Entergy region

SOUTHEAST TERRITORY

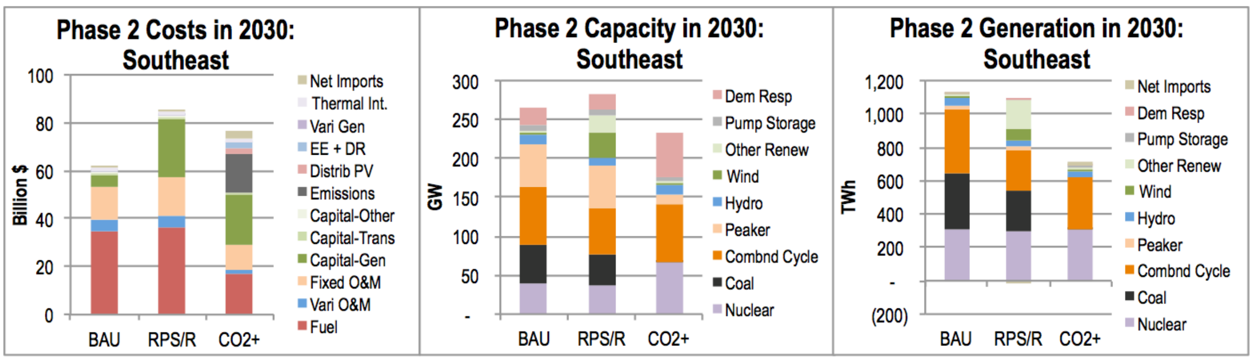

Fig. A-26. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the Southeast territory

Regions

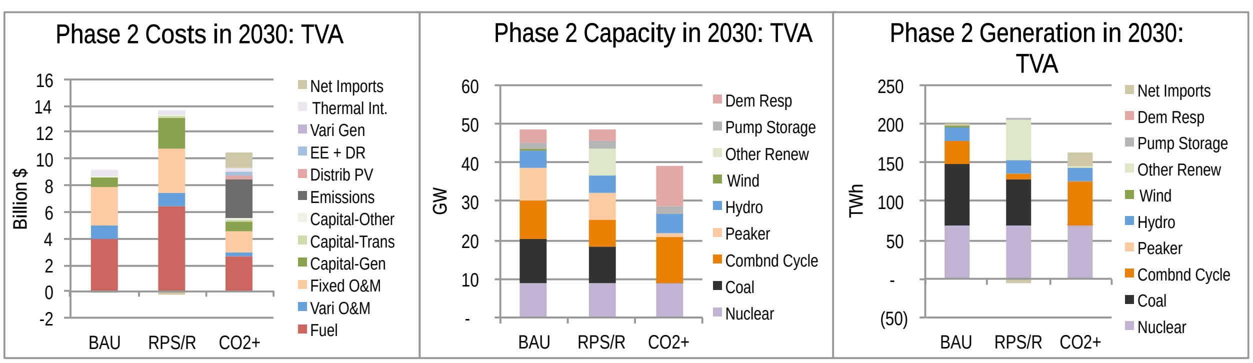

Fig. A-27. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the TVA region

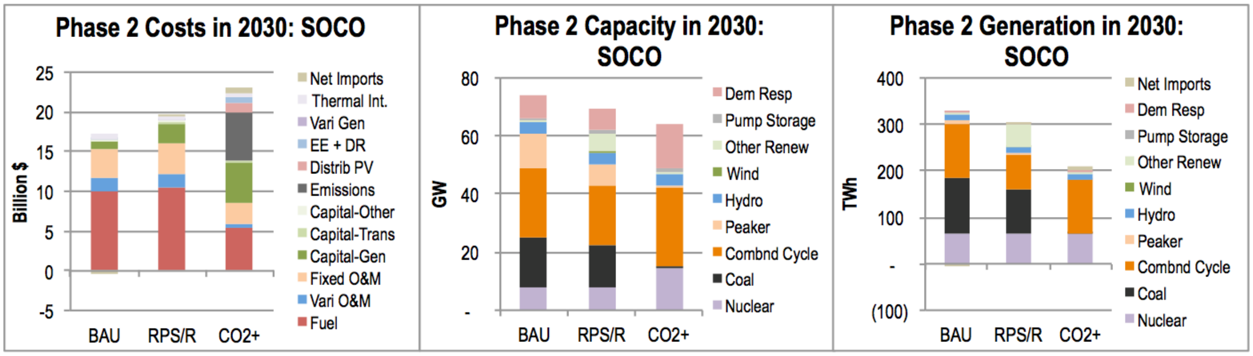

Fig. A-28. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the SOCO region

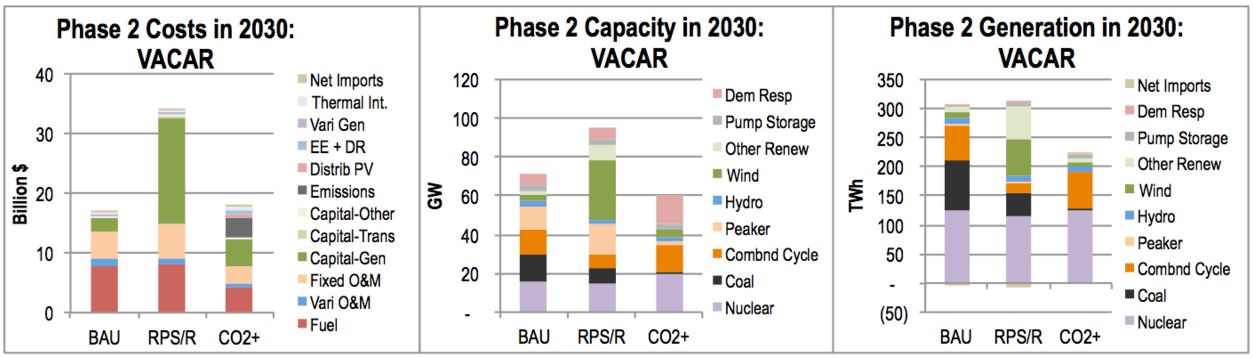

Fig. A-29. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the VACAR region

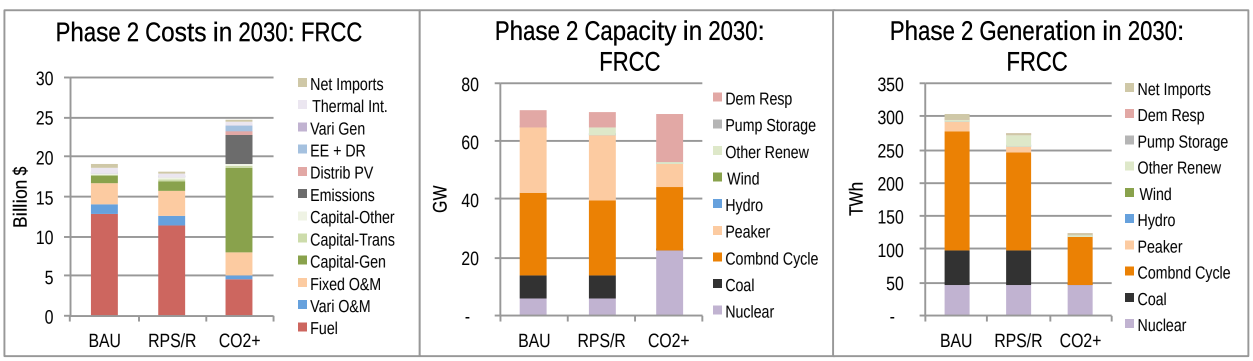

Fig. A-30. 2030 costs, capacities, and generation by type for the BAU, RPS/R and CO_2+ scenarios in the FRCC region

APPENDIX B: LINES AND TRANSFORMERS COMMON TO ALL SCENARIOS

Table B-1. Lines and Transformers Common to All Scenarios

Region	Name	Reason/Need	Description
NEISO	CT LAKES–SEA STRATTON115 kV TL	Interconnect New Generation	Include new transmission line and 1 new 115 kV substation
NEISO	PITTSTON ME–PITTSTN CLR1 115 kV TL	Interconnect New Generation	Include new transmission line and 2 new 115 kV substation
NEISO	Pittston ME 115/345 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	PITTSTON ME–HARRIS HYDRO 115 kV TL	Interconnect New Generation	Include new transmission line
NEISO	MARTHAS VYND–FALMOUTH TAP 115 kV TL	Interconnect New Generation	Include new transmission line and 1 new 115 kV substation
NEISO	Ashland ME 115/345 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	Canal 115/345 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	CANAL–HATCHVILLE 115 kV TL	Interconnect New Generation	Include new transmission line and 1 new 115 kV substation
NEISO	SEA STRATTON–PITTSTON ME 345 kV TL	Interconnect New Generation	Includes new transmission line and 2 new 345 kV substations
NEISO	SEA STRATTON–ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Sea Stratton 345/115 kV XFMR	Interconnect New Generation	1 new 345/115 kV XFMR
NEISO	Sea Stratton 345 kV–50 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	DRACTU MA–ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	DRACTU MA–MILLBURY 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	PITTSTON ME–ASHLAND ME 345 kV TL	Interconnect New Generation	Includes new transmission line and 1 new 345 kV substation
NEISO	Pittston ME 345 kV–30 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	WHITTING ME–HARRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	WHITTING ME -ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	Whiting ME 345 kV–60 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	HARRINGTON–TRENTON 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	Harrington 345 kV–40 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	TRENTON–ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Trenton 345 kV–40 Mvar Reactor	Interconnect New Generation	Includes new reactor
NEISO	BARNSTABLE–LONG TRM LSM 345 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 345 kV substation and 1 new 345/115 kV XFMR
NEISO	Barnstable 345 kV–150 Mvar SVC	Interconnect New Generation	Includes new static var controller (SVC)
NEISO	ASHLAND ME–ORRINGTON 345 kV TL	Interconnect New Generation	Includes new transmission line

Region	Name	Reason/Need	Description
NEISO	Ashland ME 345 kV–20 Mvar Cap Bank	Interconnect New Generation	Includes new capacitor bank
NEISO	Whitefield–Littleton 230 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Lost Nation–Whitefield 230 kV TL	Interconnect New Generation	Includes new transmission line and 1 new 230 kV substations
NEISO	Paris–Lost Nation 230 kV TL	Interconnect New Generation	Includes new transmission line and 1 new 230 kV substations
NEISO	Pontook–Paris 230 kV TL	Interconnect New Generation	Includes new transmission line and 2 new 230 kV substations
NEISO	STURTEVANT–LIVERMORE FL 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Merrimack 230 kV–150 Mvar SVC	Low Voltage	Includes new SVC
NEISO	Scobie–Tewksbury 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	BEEBE RIVER–WEBSTER 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	WEBSTER–DEERFIELD 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Woburn–N. Cambridge 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	BARNSTABLE–HATCHVILLE 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	BARNSTABLE–HARWICH MCGR 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	FALMOUTH TAP–HATCHVILLE 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	WELLFLEET–ORLEANS 115 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	HARWICH MCGR–ORLEANS 115 Kv TL	Interconnect New Generation	Includes new transmission line
NEISO	MILLBURY–MANCHESTER 345 kV TL	Interconnect New Generation	Includes new transmission line
NEISO	Tewksbury–Woburn 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	Ward Hill–Wakefield JCT 345 kV TL	Loading >100% of System Emergency	Includes new transmission line
NEISO	KENYON–KENT COUNTY 115 kV TL	Interconnect New Generation	Includes new transmission line
NYISO A-F	Leeds–Pleasant Valley 345 kV	Loading >100% of System Emergency	New 345 kV line
PJM ROM	Brighton–Kemptown 500 kV TL (PATH)	Loading >100% of System Emergency	Upgrade oper temp facil/reconductor 500 KV line
PJM ROM	Conastone–Kemptown 500 kV TL (PATH)	Loading >100% of System Emergency	Upgrade operating temperature facil/reconductor 500 KV line
PJM ROM	North Temple–North Kill 230 kV TL (terminal equip. uprate)	Interconnect New Generation	Upgrade 230 KV sub/upgrade 230 KV sub
PJM ROM	North Temple–Hosensack 230 kV TL (terminal equip. uprate)	Interconnect New Generation	Upgrade 230 KV sub/upgrade 230 KV sub
PJM ROR	Doubs–Kemptown 500 kV TL (PATH)	Loading >100% of System Emergency	Upgrade operating temperature facil/reconductor 500 KV line
PJM ROR	Meadow Brook–Welton Springs 500 kV TL (PATH)	Loading >100% of System Emergency	Upgrade operating temperature facil/reconductor 500 KV line
PJM ROR	Welton Springs–Kemptown 765 kV TL (PATH)	Loading >100% of System Emergency	New 765 KV line/new 765 KV line

Region	Name	Reason/Need	Description
PJM ROR	Welton Springs–John Amos 765 kV TL (PATH)	Loading >100% of System Emergency	New 765 KV line/new 765 KV line
PJM ROR	Welton Springs–Mt Storm 500 kV TL (PATH)	Loading >100% of System Emergency	Upgrade operating temperature facil/reconductor 500 KV line
MISO MI	MCV–Tittabawasee 345 Ckt 1 Reconductor	Loading >100% of System Emergency	Reconductored Transmission Line + 2 Upgraded Bays
MISO MI	MCV–Tittabawasee 345 Ckt 2 Reconductor	Loading >100% of System Emergency	Reconductored Transmission Line + 2 Upgraded Bays
ENT	New Sportman 345/161 kV third auto	Loading >100% of System Emergency	Add 345 kV Auto
VACAR	Wake-Wommack 500 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 500 kV substation
VACAR	Cumberland-Wommack 500 kV TL	Interconnect New Generation	Includes new transmission line, 1 new 500 kV substation
VACAR	New Bern 500/230 kV XFMR	Interconnect New Generation	New transformer
VACAR	New Bern 500/230 kV XFMR	Interconnect New Generation	New transformer
VACAR	New Bern-Wommack 500 kV TL	Interconnect New Generation	Includes New Transmission Line
VACAR	Antioch 500/230 kV XFMR	Loading >100% of System Emergency	New transformer
VACAR	Antioch 500/230 kV XFMR	Loading >100% of System Emergency	New transformer
Non-RTO Midwest	Upgrade Trimble Co to Middletown 345 kV	Loading >100% of System Emergency	Upgrade Operating Temperature
ENT	New Lewis Creek to West Conroe SS 230 kV	Loading >100% of System Emergency	Construct new 230 kV Line and 230 kV substation at W. Conroe and terminal at Lewis Creek
ENT	New 230/138/13/8 kV three winding transformer at Conroe SS	Loading >100% of System Emergency	Add 230 kV Auto
ENT	New West Conroe SS to Grimes 230 kV	Loading >100% of System Emergency	Construct new 230 kV Line and 230 kV substation at Grimes
ENT	Upgrade West Conroe SS to Conroe 138 kV	Loading >100% of System Emergency	Upgrade 138 kV line
ENT	New 345/230 kV auto at Grimes	Loading >100% of System Emergency	Add 345 kV Auto
ENT	New Addis to Tiger 230 kV Ckt 2	Loading >100% of System Emergency	Construct new 230 kV line and add terminals at Addis and Tiger
ENT	Construct second Dowmeter to Air Liquide Tap 230 kV	Loading >100% of System Emergency	Construct new 230 kV line and add terminals at Dowmeter
ENT	Upgrade Air Liquide Tap to Chenango 230 kV	Loading >100% of System Emergency	Upgrade 230 kV line
ENT	Upgrade Chenango to Iberville 230 kV line	Loading >100% of System Emergency	Upgrade 230 kV line
ENT	Upgrade Iberville to Evergreen 230 kV line	Loading >100% of System Emergency	Upgrade 230 kV line
MISO IN	7WILSON 345–7REID 345 Reconductor	Loading >100% of System Emergency	Reconductored Transmission Line + 2 Upgraded Bays
SOCO	McGrau Ford–Hopewell 230 kV TL	Loading >100% of System Emergency	230kV Transmission Line, 230kV Bay @ McGrau Ford & Hopewell
SOCO	Hopewell 230 kV/115 kV TL	Loading >100% of System Emergency	230 kV/115kV XFMR
SOCO	Hopewell–Milton 230 kV TL	Loading >100% of System Emergency	230 kV Transmission Line
FRCC	Re-conductor CURRY FD 230.00	Loading >100% of	Replace conductors

Region	Name	Reason/Need	Description
	to STANTONW 230.00	System Normal	
FRCC	Re-conductor SO WOOD 230.00 to C CENTER 230.00	Loading >100% of System Normal	Replace conductors
FRCC	Re-conductor TAFT 230.00 to C CENTER 230.00	Loading >100% of System Normal	Replace conductors
MISO W	Brookings County–Big Stone 345	Interconnect New Generation	New Transmission Line + 2 Bays
MAPP CA	MYSLKRD-DUNLOP 230 kV TL	Loading >100% of System Emergency	Line, two 230 kV bays,
MAPP CA	DUNLOP-PONTON 230 kV TL	Loading >100% of System Emergency	Line, two 230 kV bays,
MAPP CA	RIEL 500/230 kV XFMR	Loading >100% of System Emergency	One 500 kV transformer, one 500 kV bay
MISO WUMS	Oak Creek-Elm Rd 230-345 kV T884 XFMR Replacement	Loading >100% of System Emergency	Includes 1 new 345kV/230kV XFMR

APPENDIX C. NATIONAL VERSUS REGIONAL FUTURE REGION-SPECIFIC RESULTS

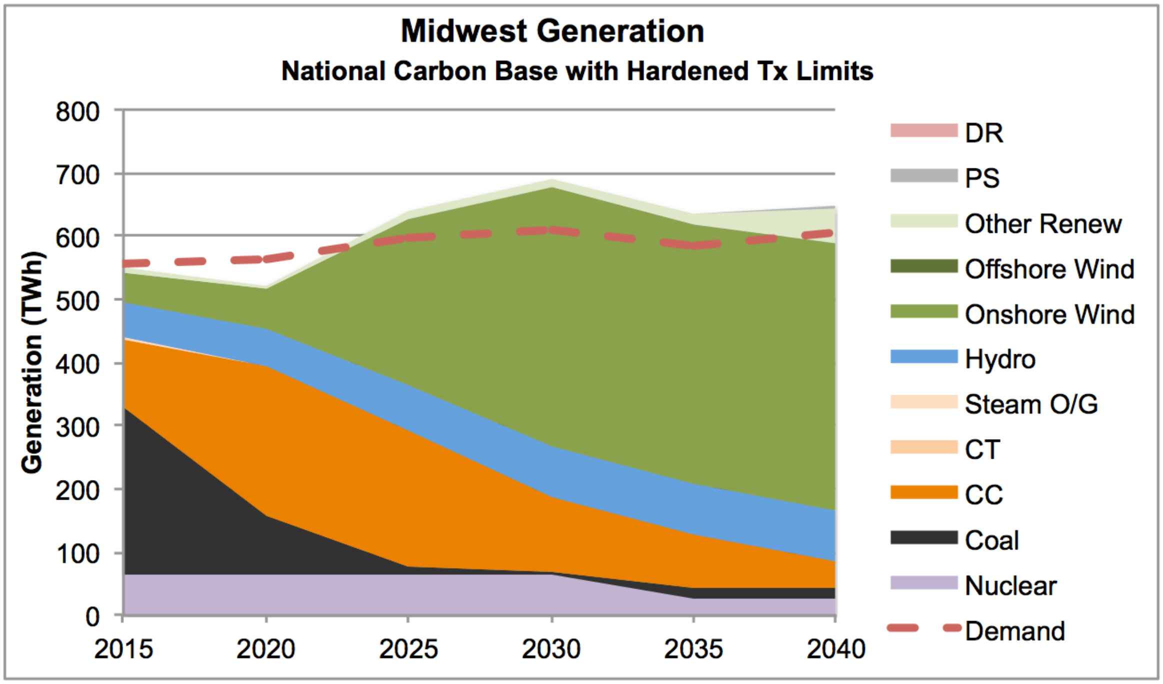

Fig. C-1. Midwest generation over study period in the CO_2/N future

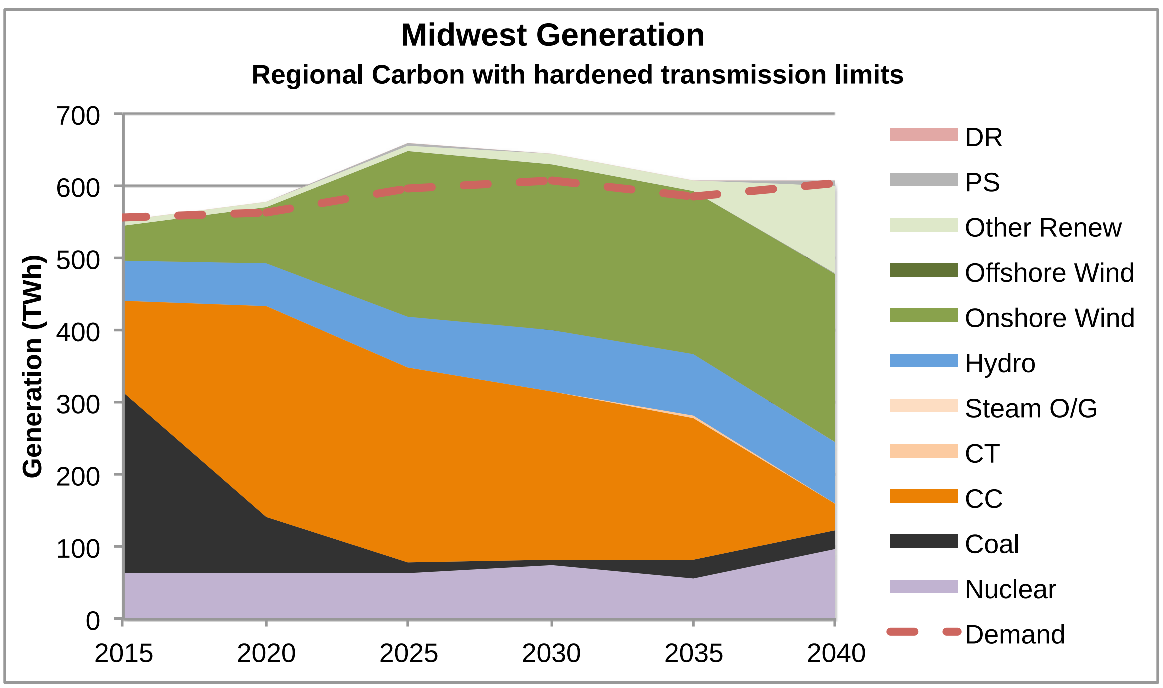

Fig. C-2. Midwest generation over study period in the CO_2/R future

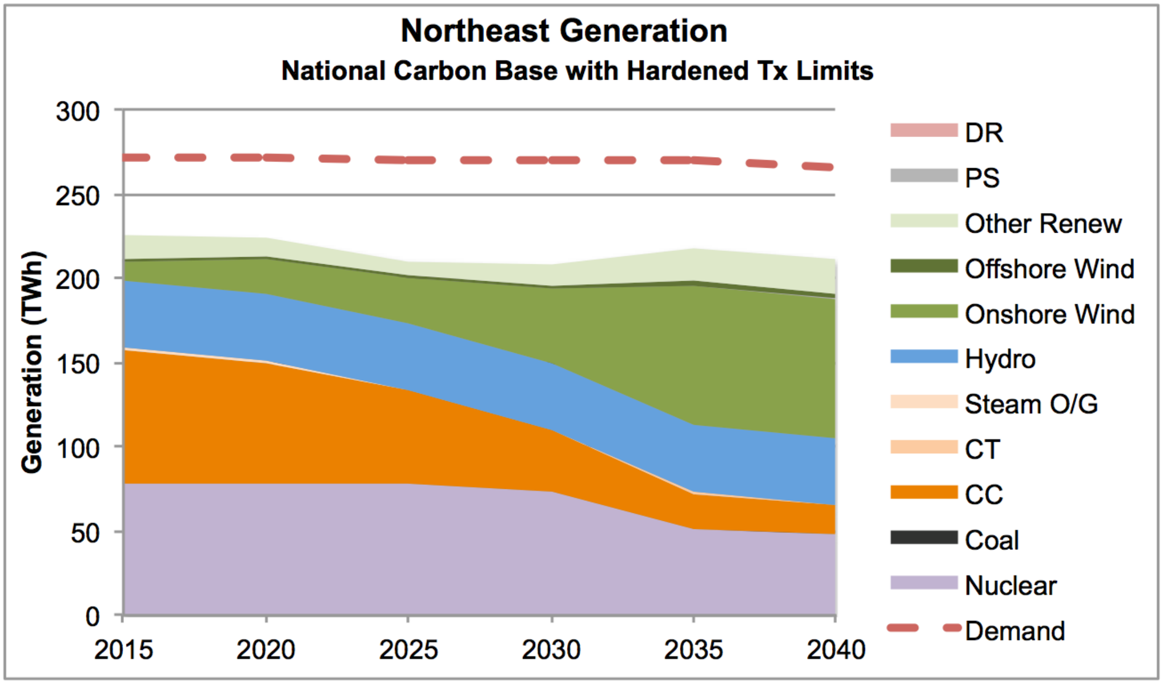

Fig. C-3. Northeast generation over study period in the CO_2/N future

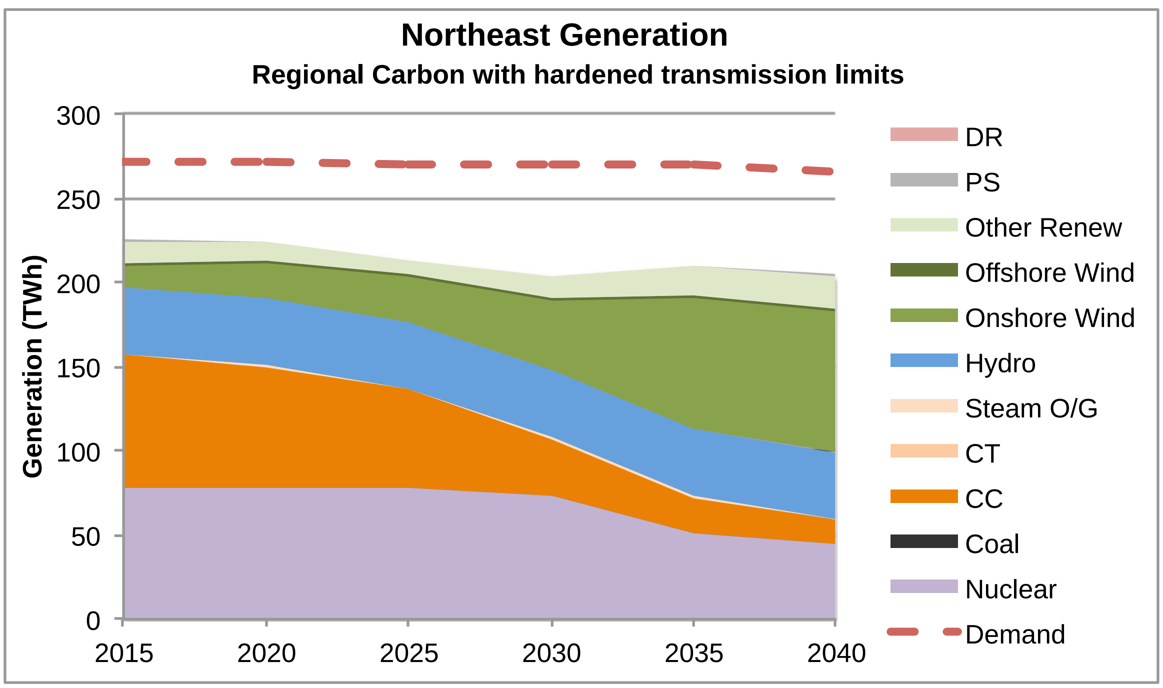

Fig. C-4. Northeast generation over study period in the CO_2/R future

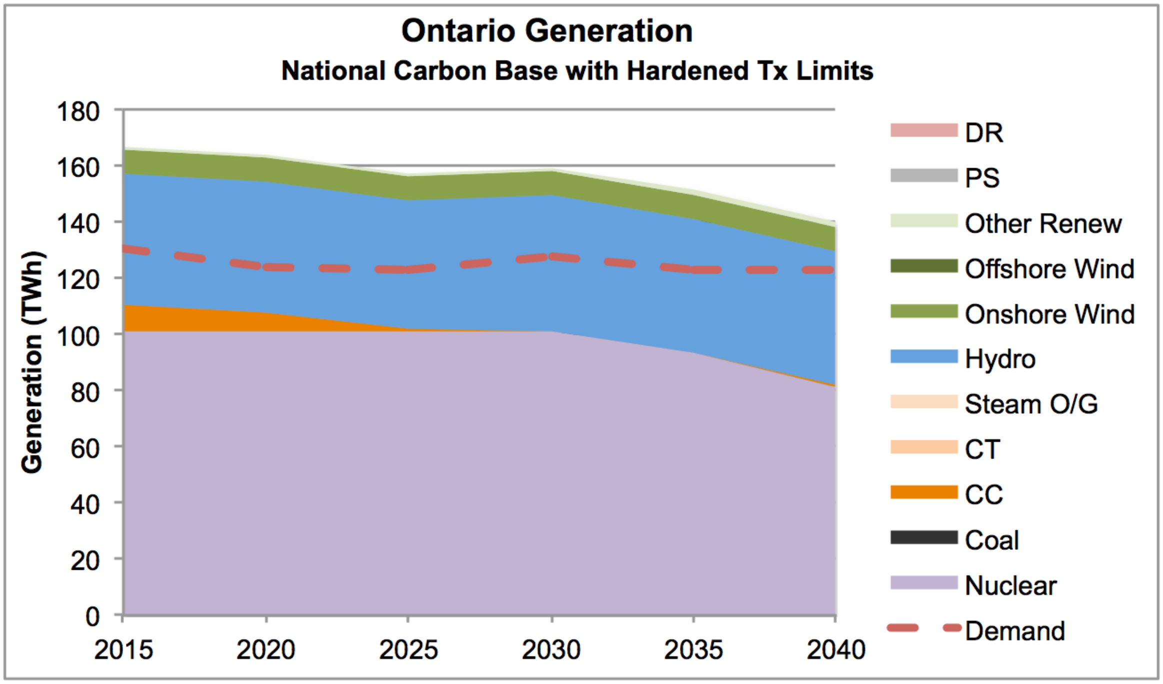

Fig. C-5. Ontario generation over study period in the CO_2/N future

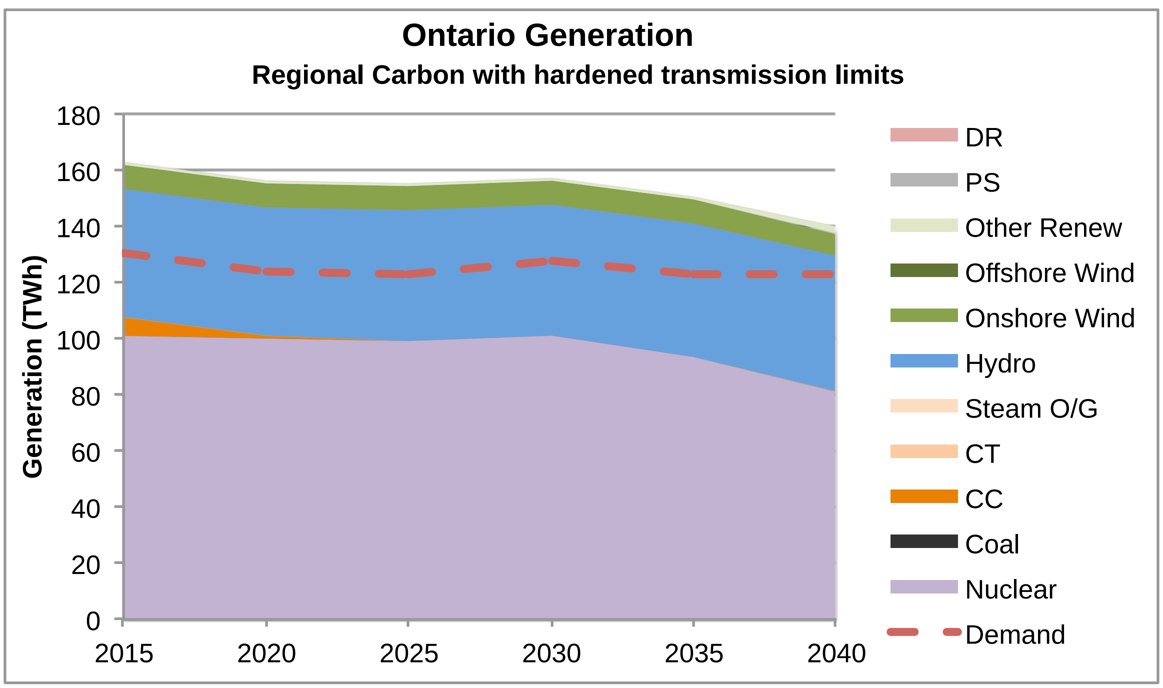

Fig. C-6. Ontario generation over study period in the CO_2/R future

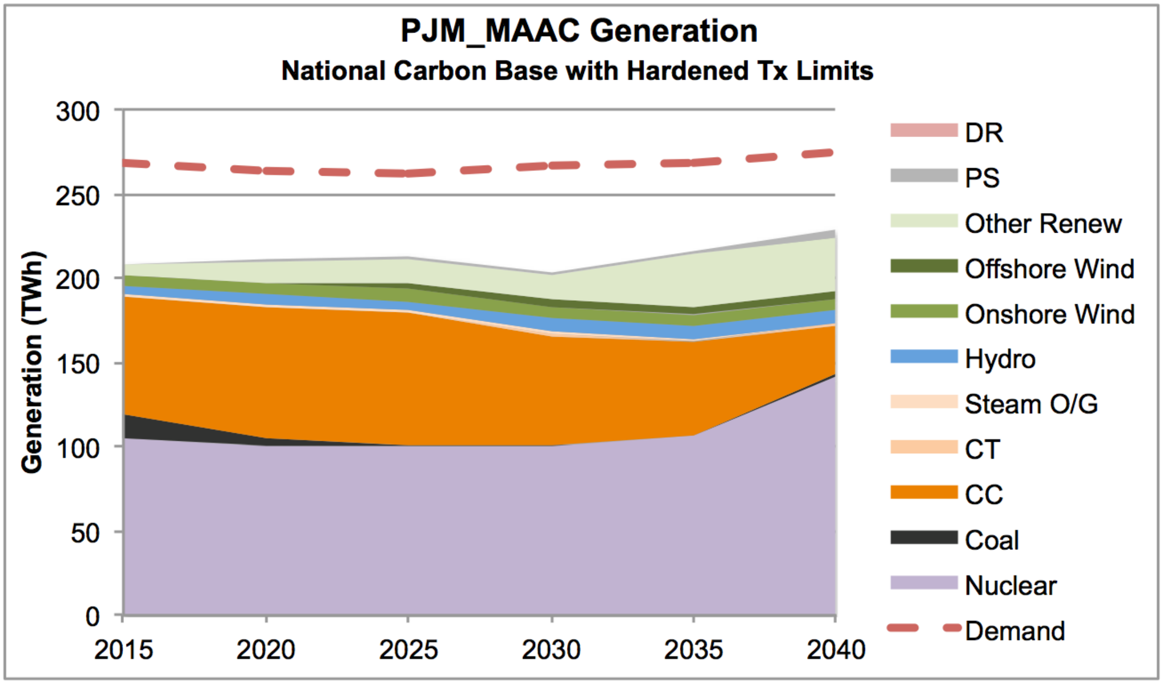

Fig. C-7. PJM MAAC generation over study period in the CO_2/N future

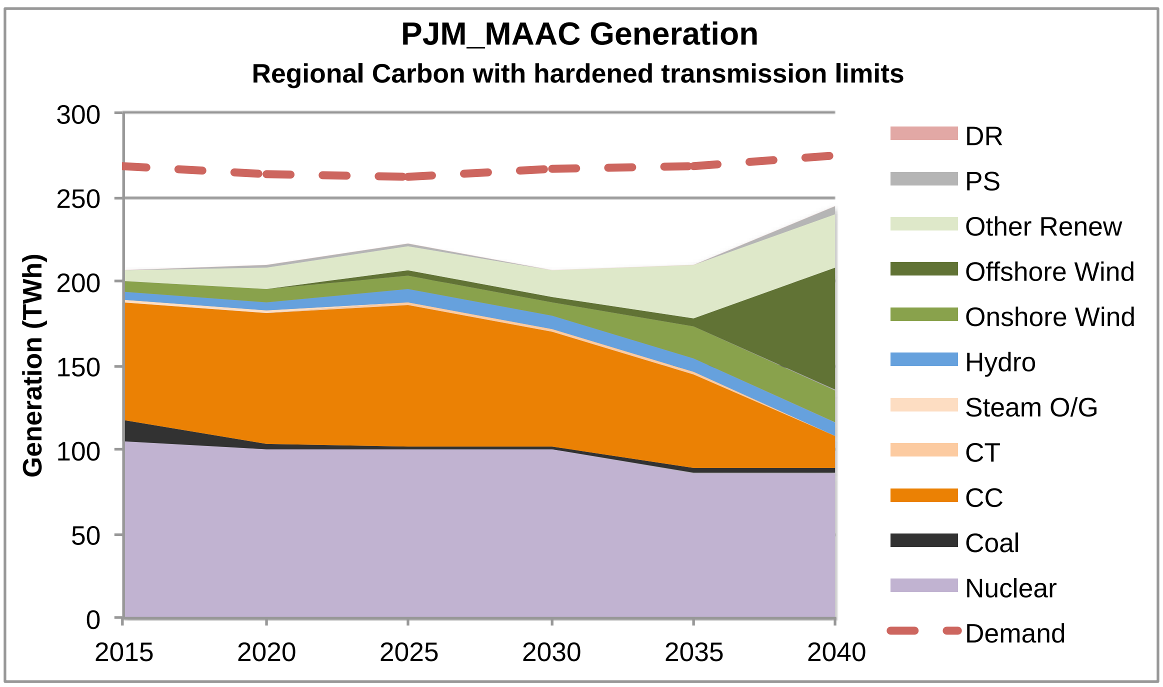

Fig. C-8. PJM MAAC generation over study period in the CO_2/R future

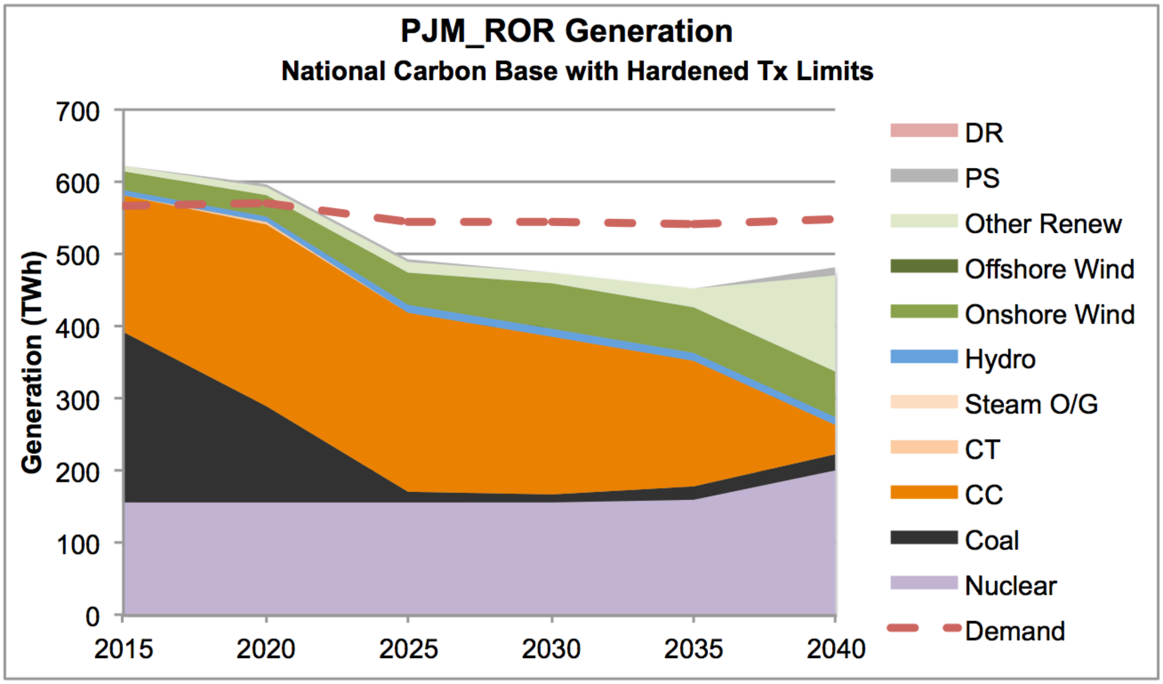

Fig. C-9. PJM ROR generation over study period in the CO_2/N future

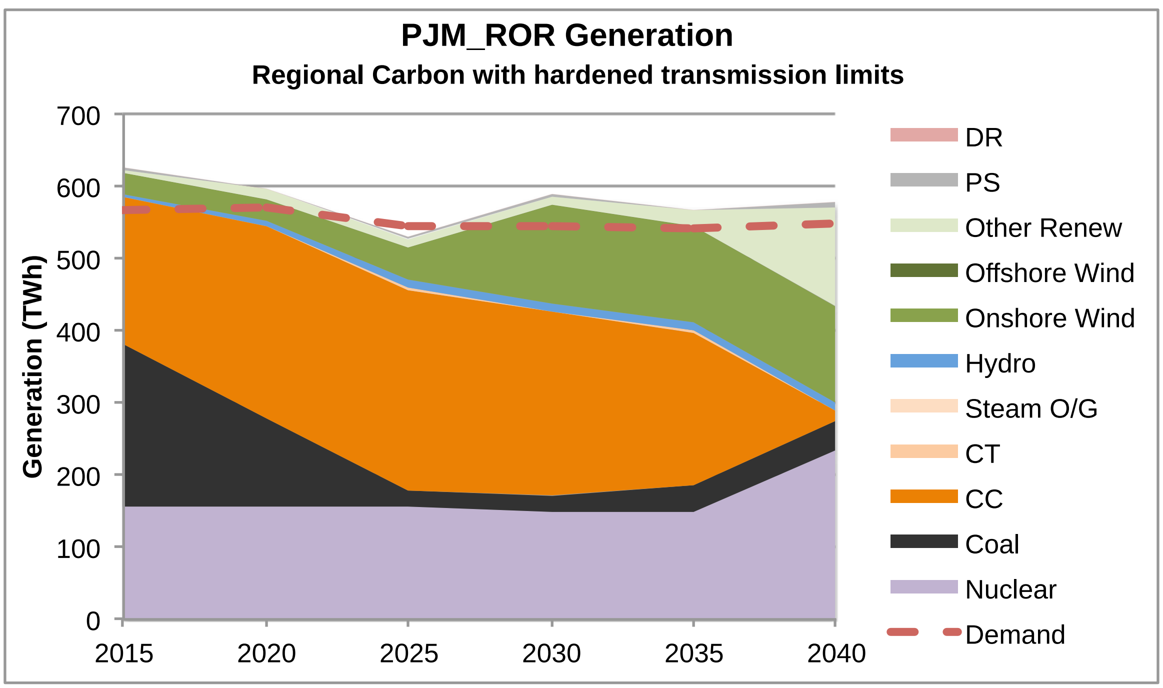

Fig. C-10. PJM ROR generation over study period in the CO_2/R future

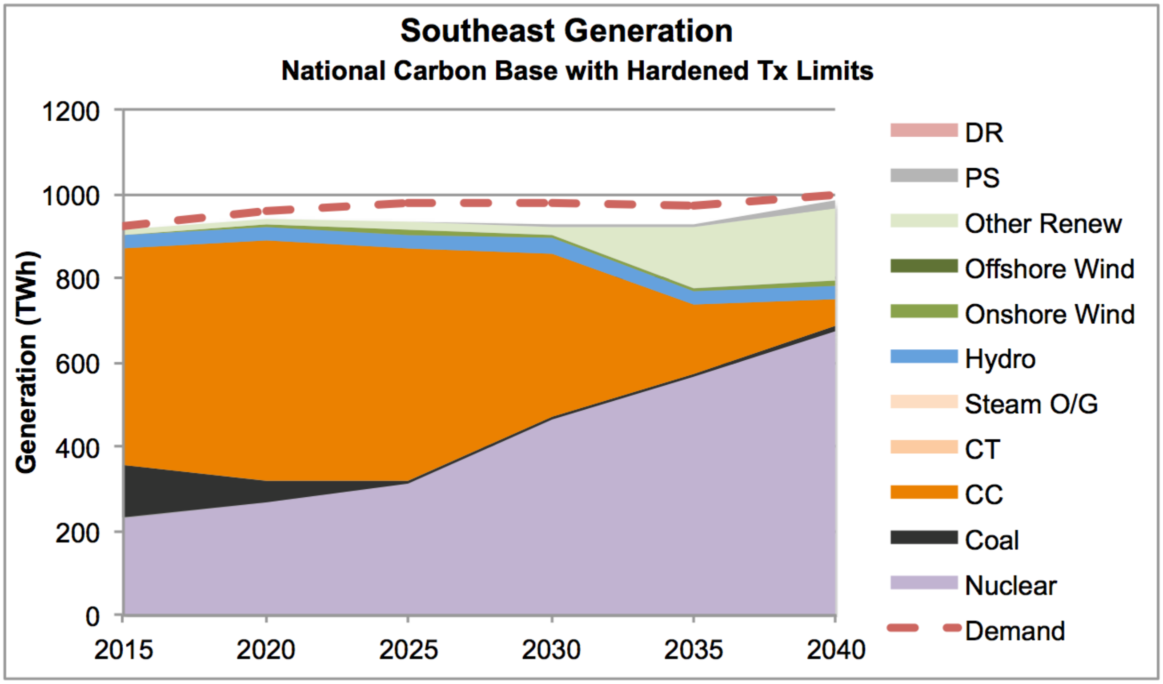

Fig. C-11. Southeast generation over study period in the CO_2/N future

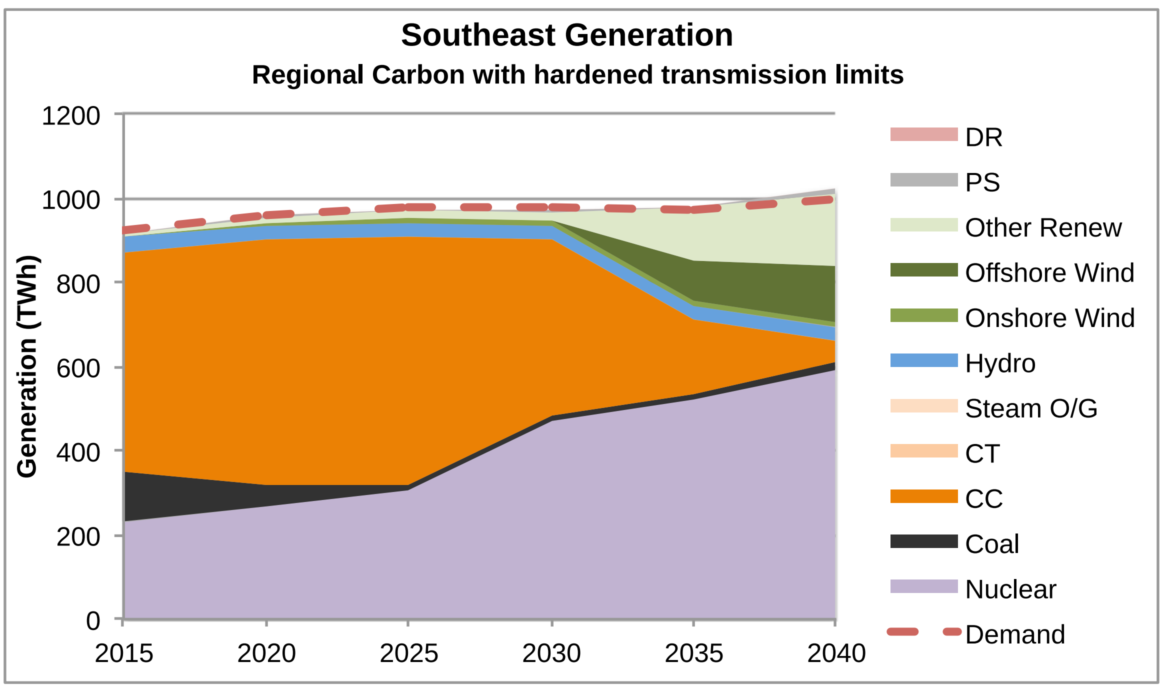

Fig. C-12. Southeast generation over study period in the CO_2/R future

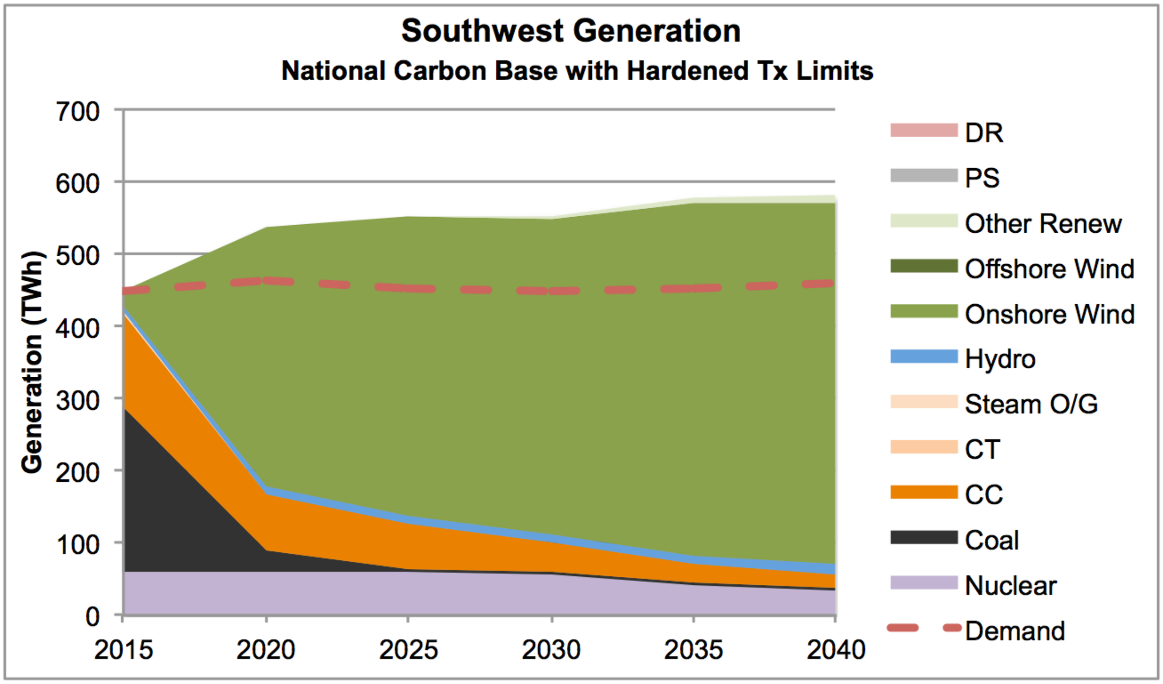

Fig. C-13. Southwest generation over study period in the CO_2/N future

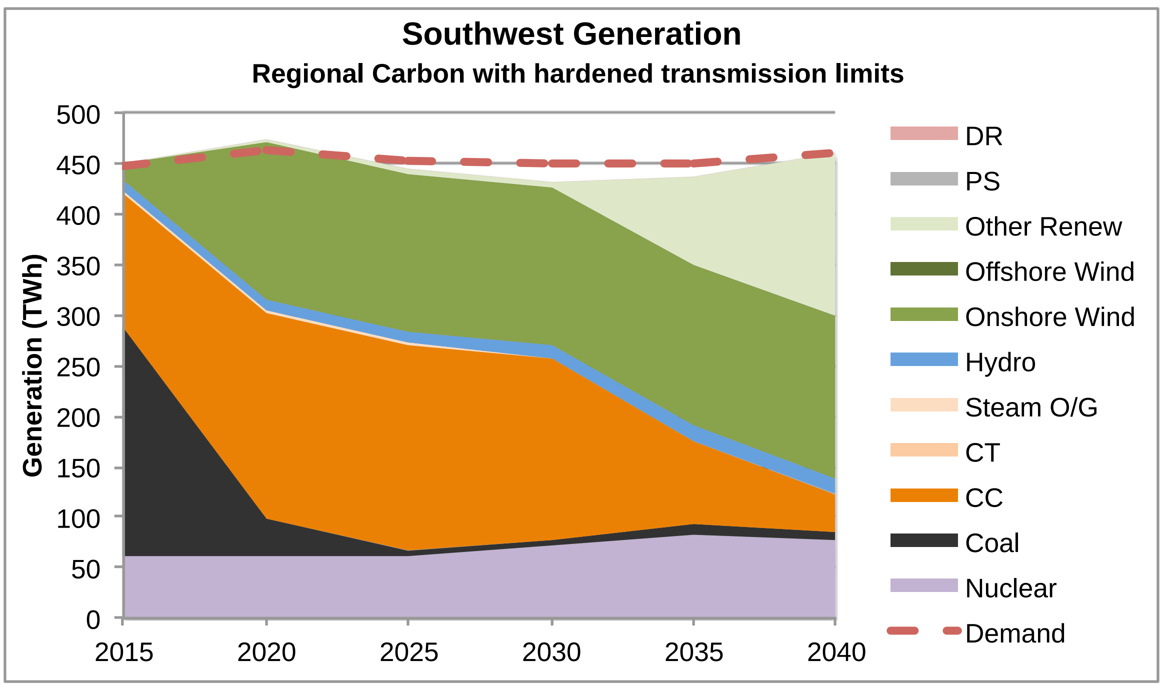

Fig. C-14. Southwest generation over study period in the CO_2/R future

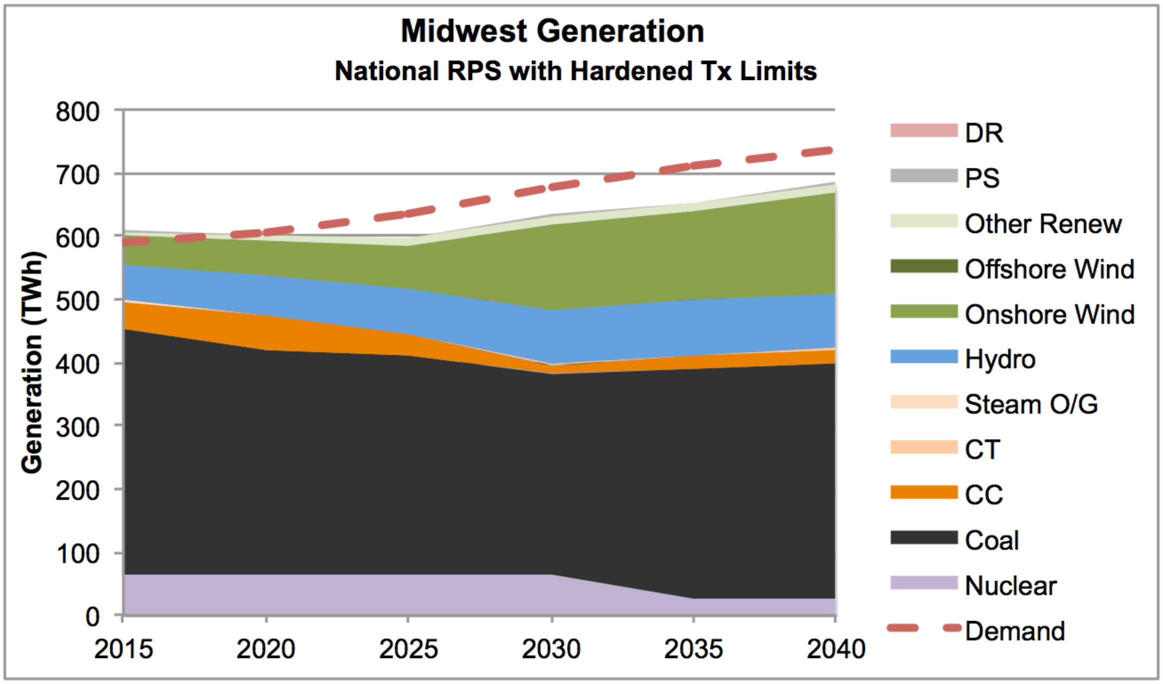

Fig. C-15. Midwest generation over study period in the RPS/N future

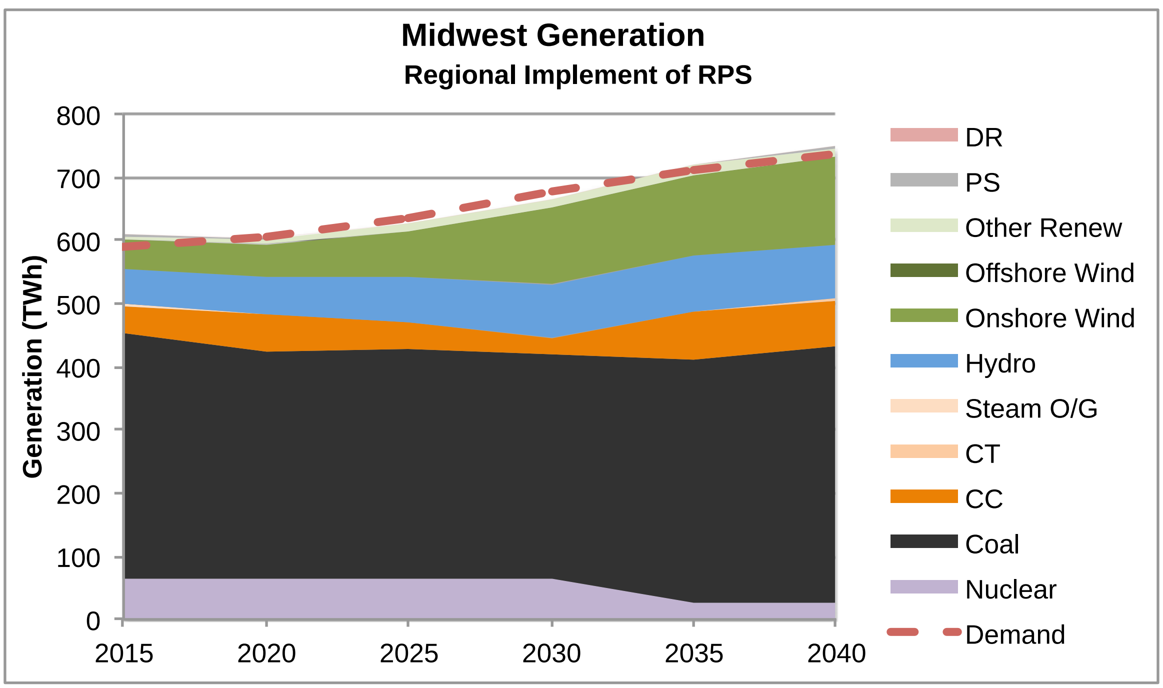

Fig. C-16. Midwest generation over study period in the RPS/R future

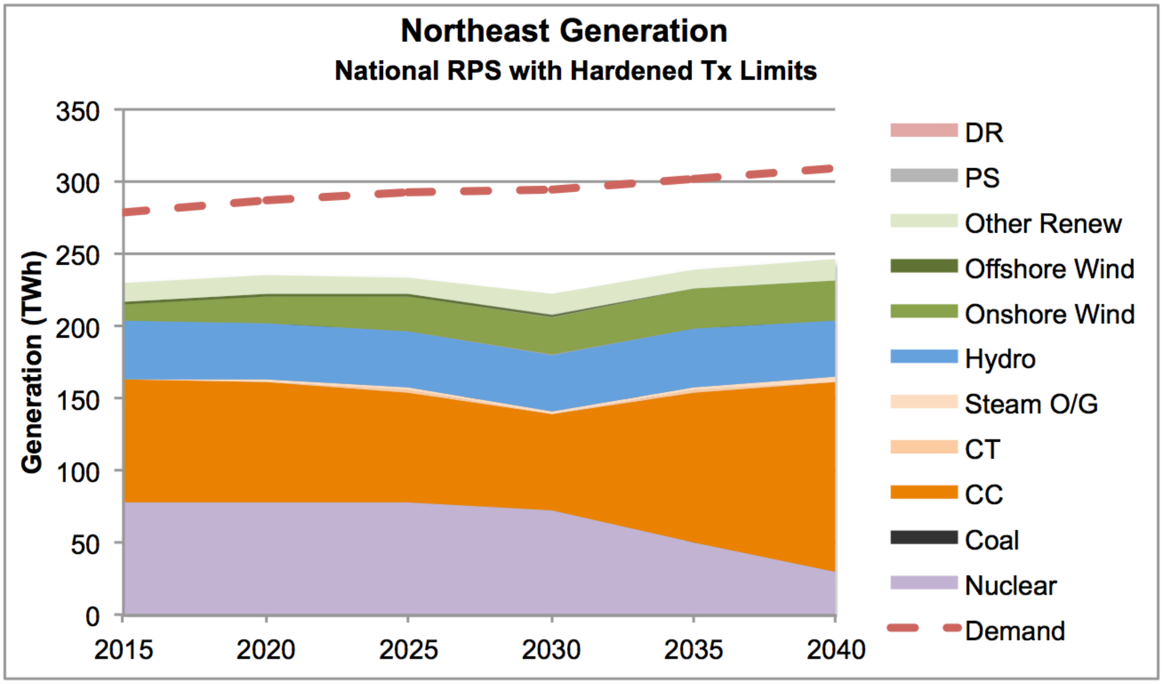

Fig. C-17. Northeast generation over study period in the RPS/N future

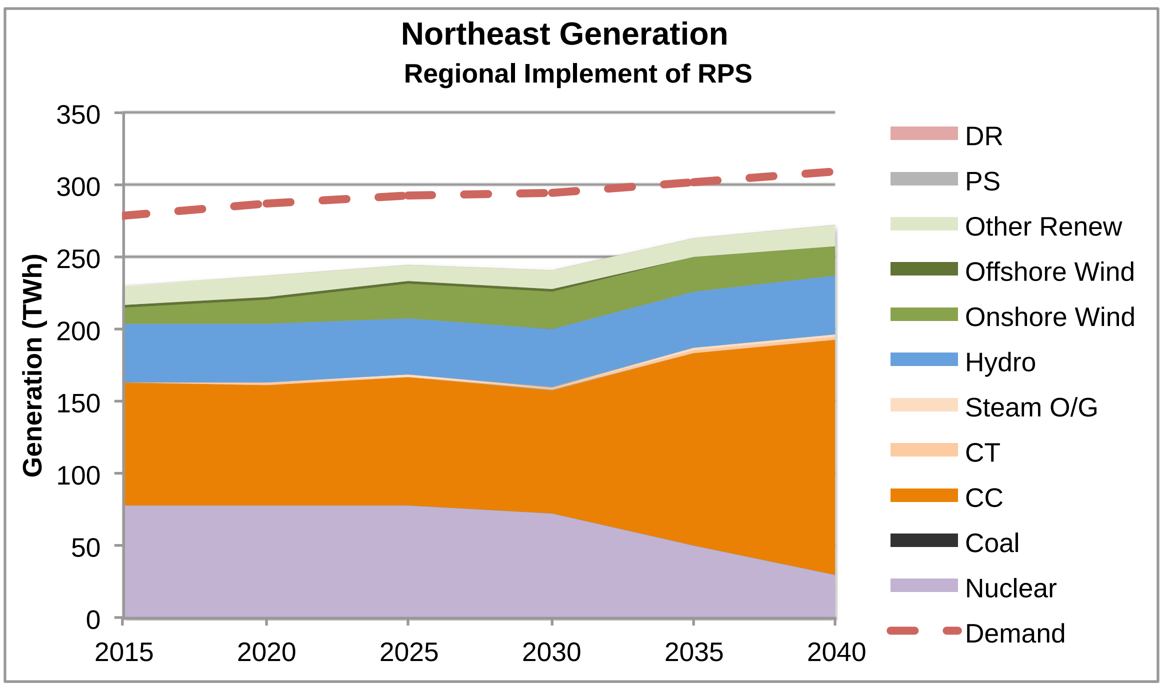

Fig. C-18. Northeast generation over study period in the RPS/R future

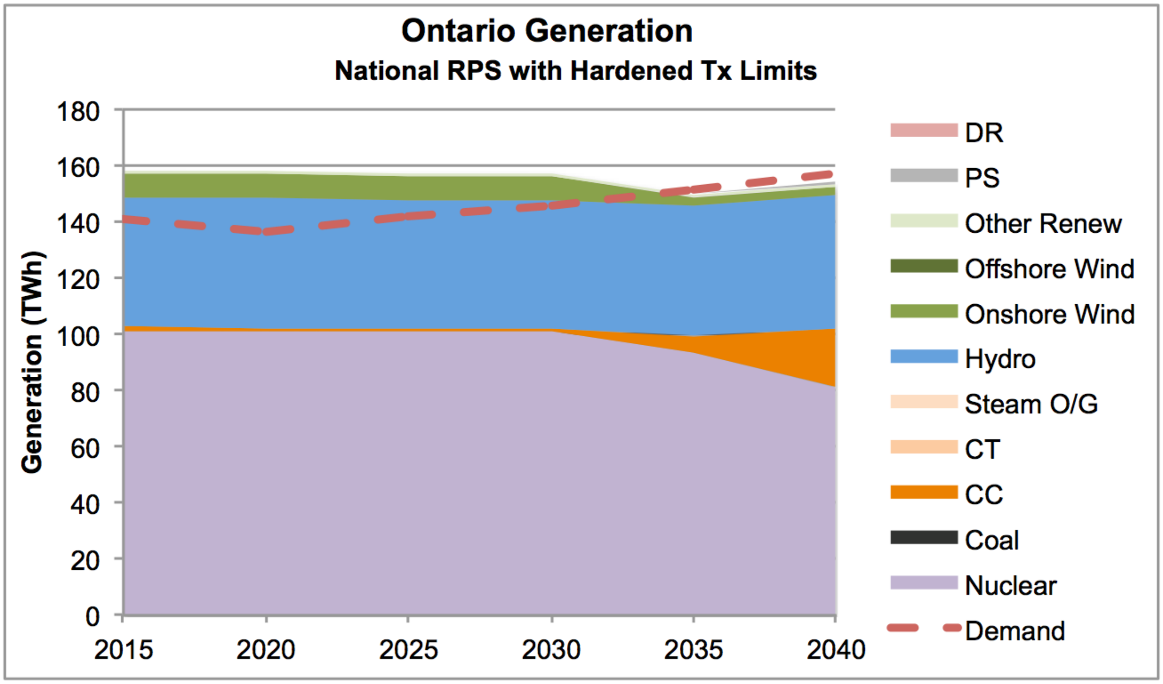

Fig. C-19. Ontario generation over study period in the RPS/N future

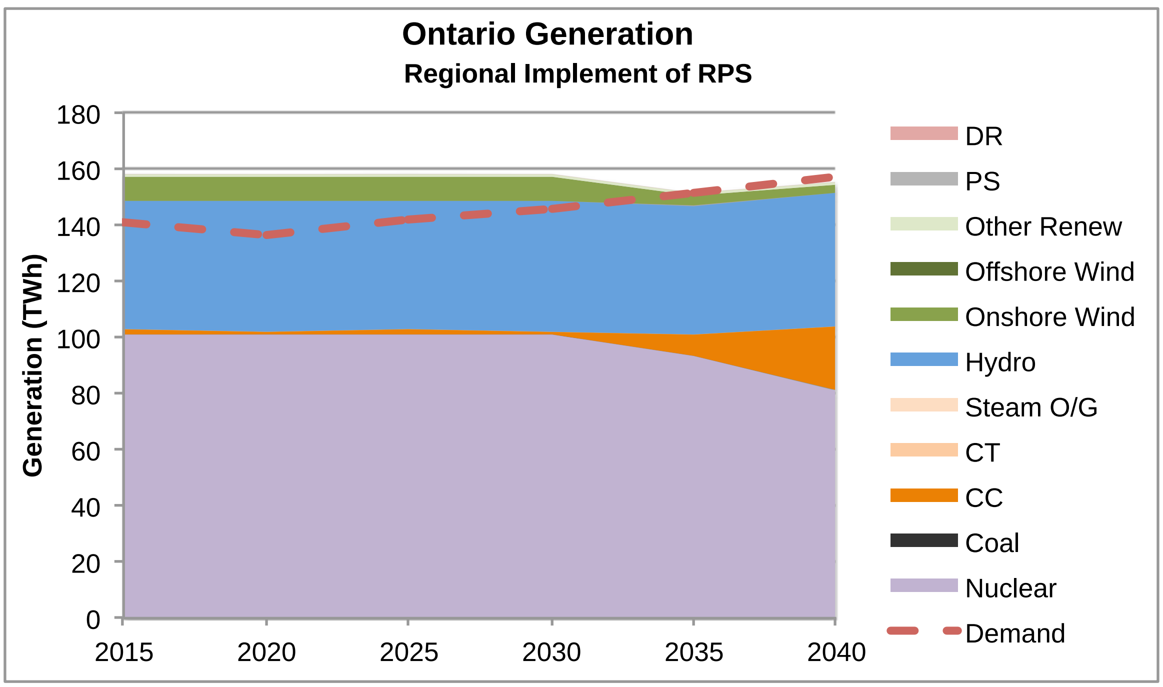

Fig. C-20. Ontario generation over study period in the RPS/R future

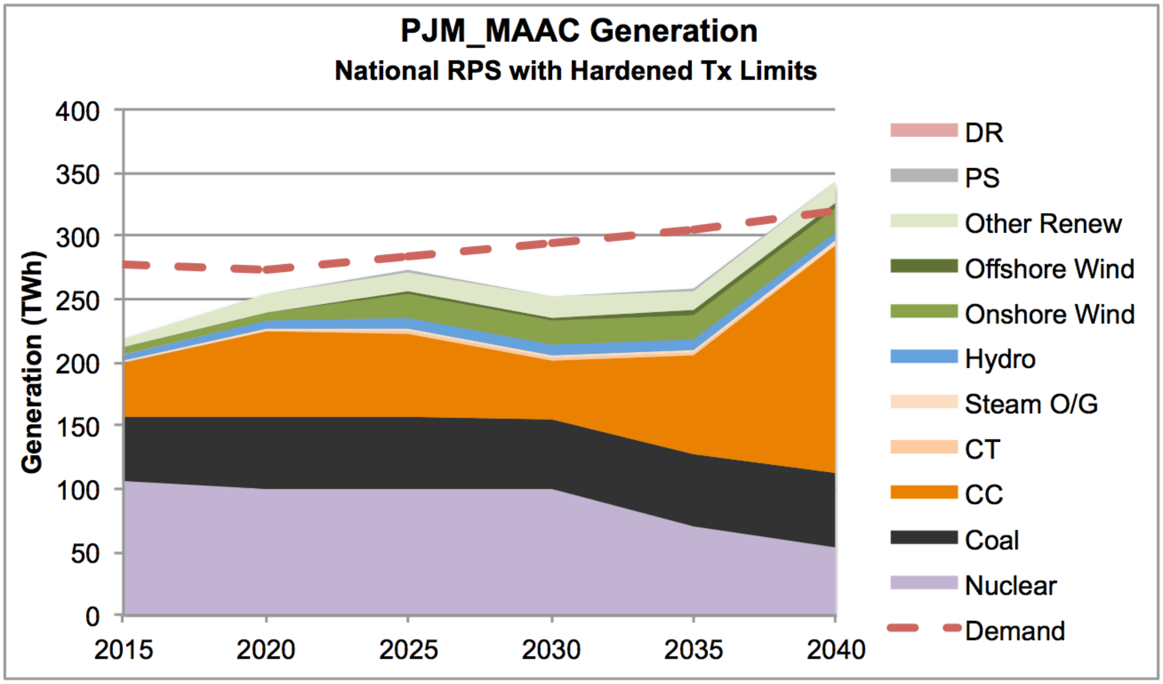

Fig. C-21. PJM MAAC generation over study period in the RPS/N future

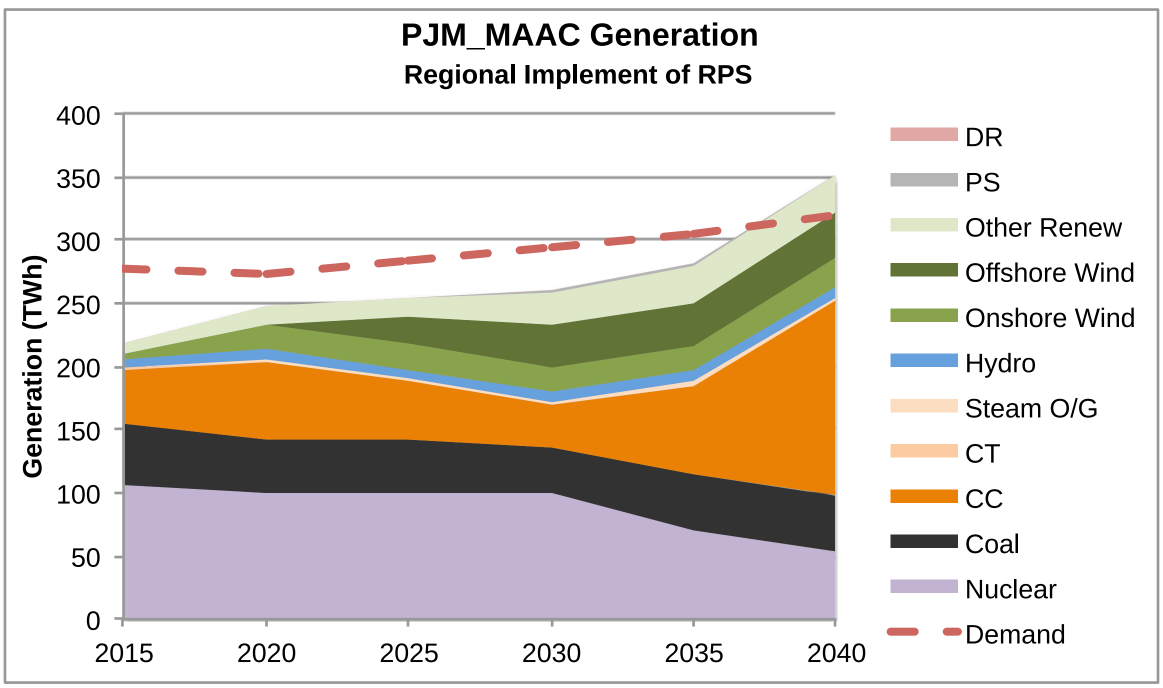

Fig. C-22. PJM MAAC generation over study period in the RPS/R future

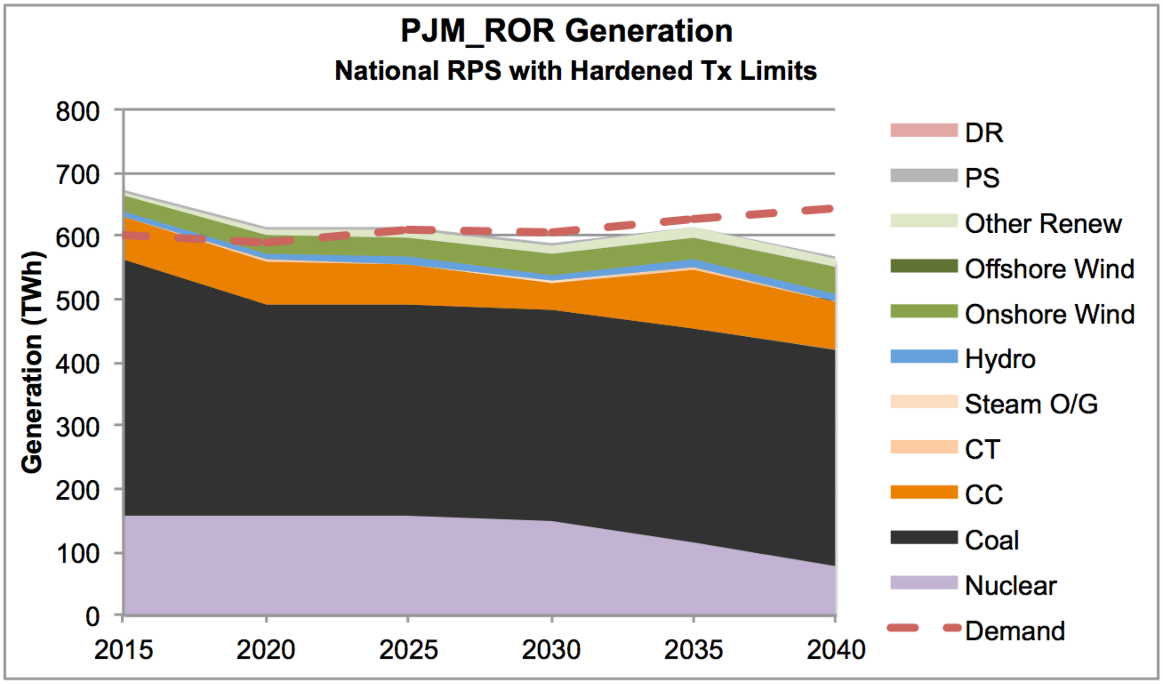

Fig. C-23. PJM ROR generation over study period in the RPS/N future

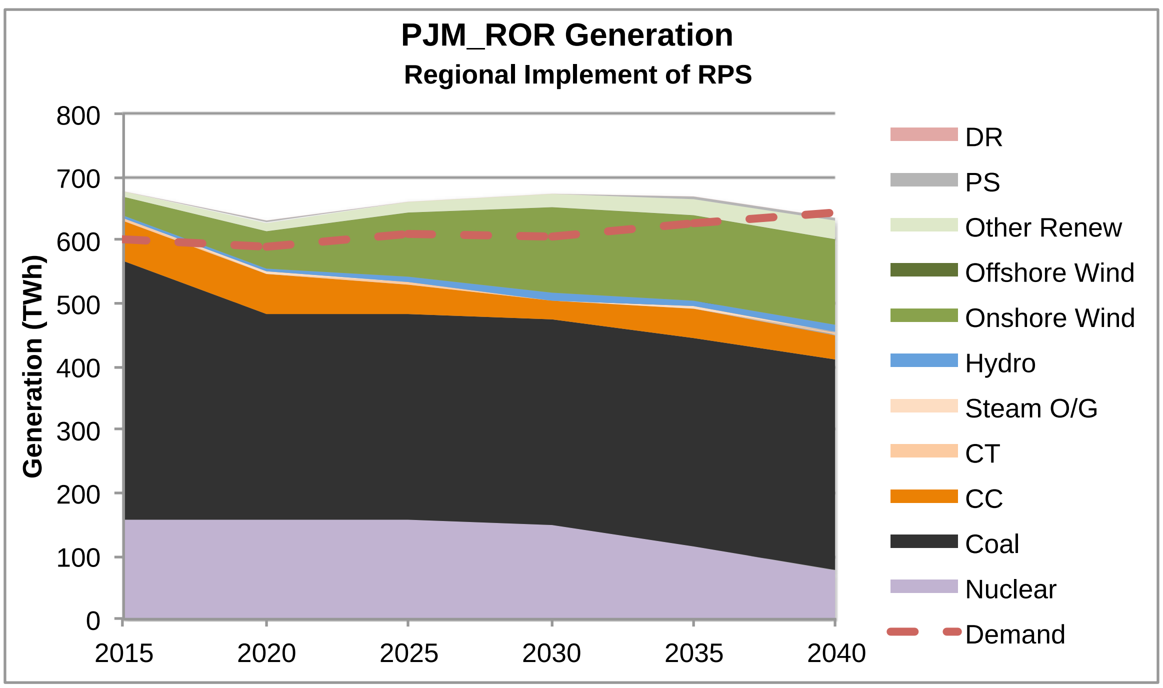

Fig. C-24. PJM ROR generation over study period in the RPS/R future

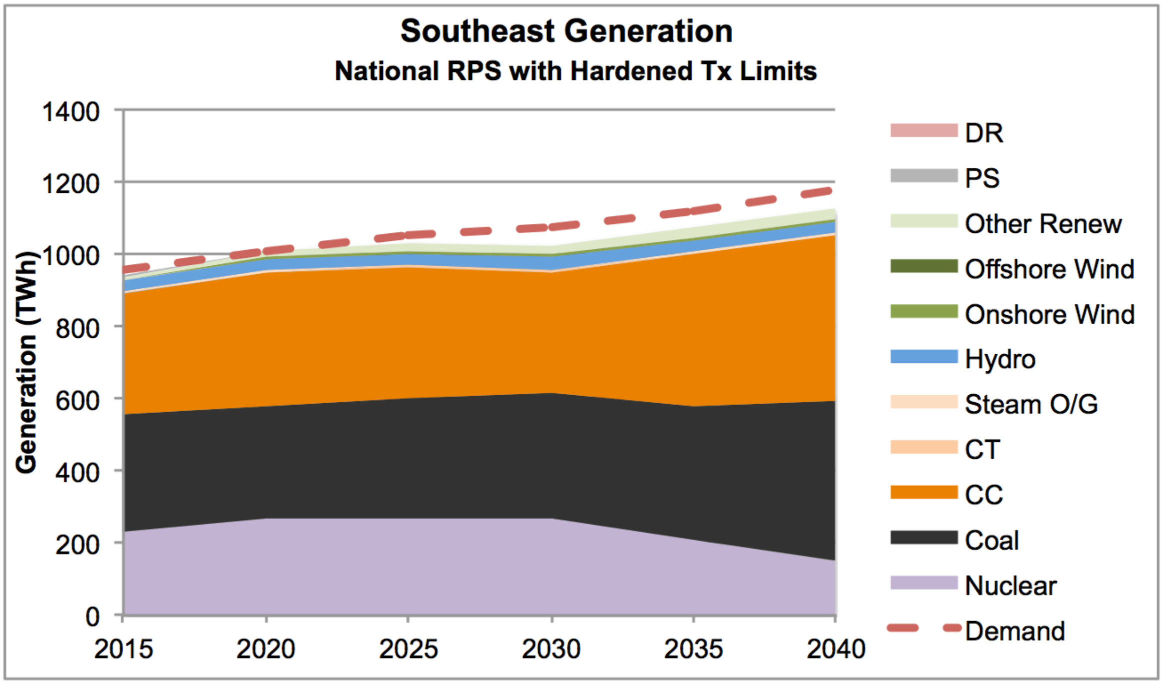

Fig. C-25. Southeast generation over study period in the RPS/N future

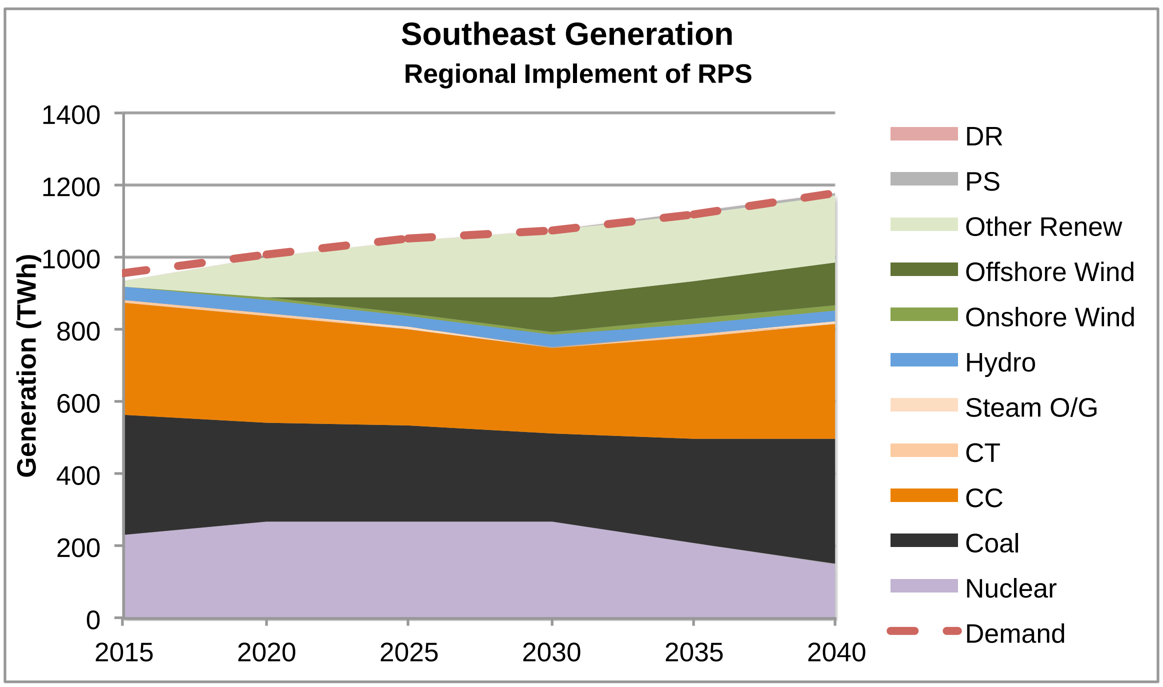

Fig. C-26. Southeast generation over study period in the RPS/R future

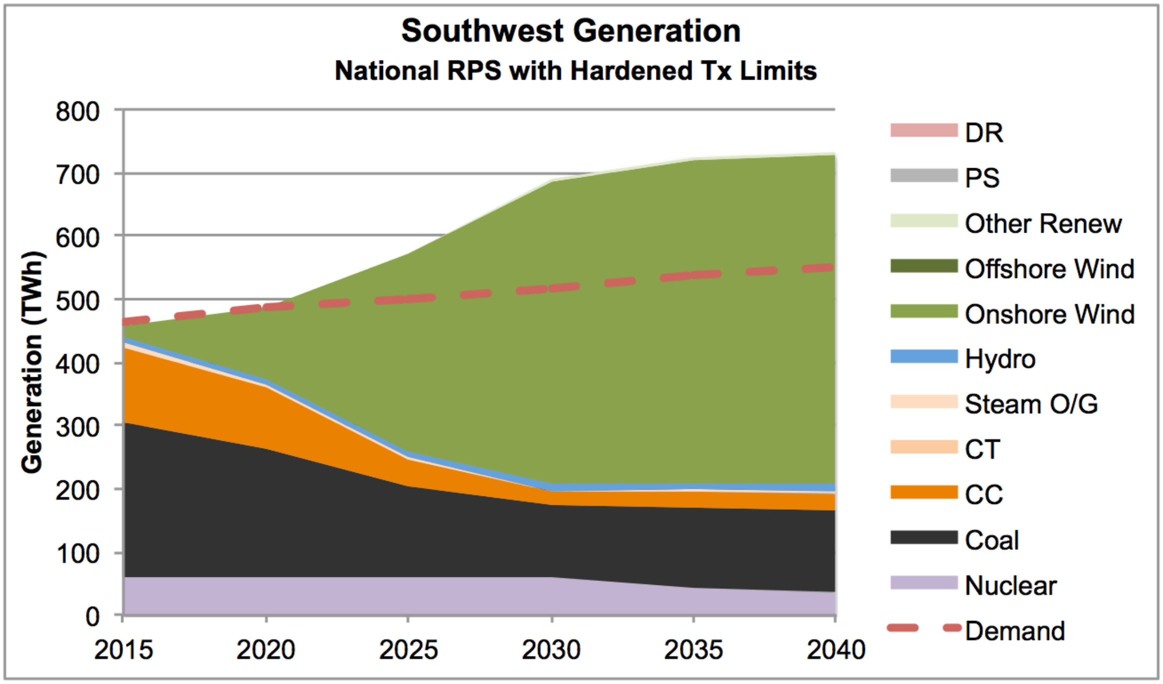

Fig. C-27. Southwest generation over study period in the RPS/N future

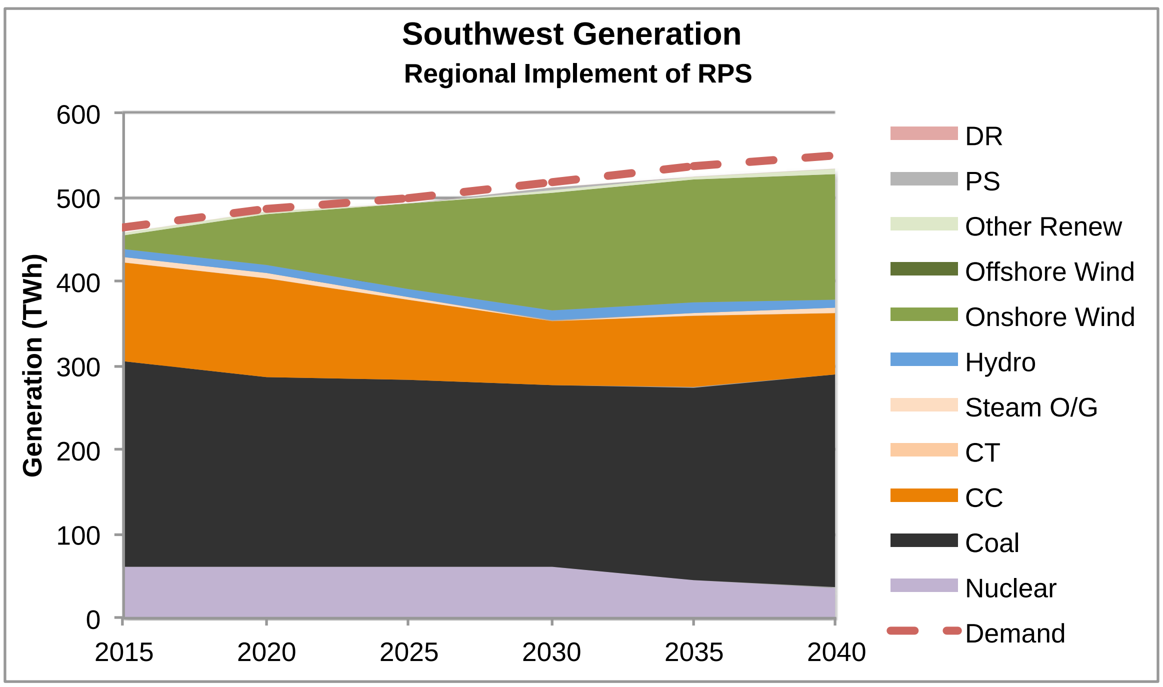

Fig. C-28. Southwest generation over study period in the RPS/R future