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Additional EIPC Study Analysis: Report on Low Priority Topics

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Electrical and Electronics Systems Research Division

ADDITIONAL EIPC STUDY ANALYSIS: INTERIM REPORT ON LOW PRIORITY TOPICS

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August 2014

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CONTENTS

LIST OF FIGURES

Figure **Page**

LIST OF TABLES

Table **Page**

ABBREVIATIONS AND ACRONYMS

AEO	*Annual Energy Outlook* (EIA report)
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 Rivers 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
GE MAPS	General Electric Multi-Area Production Simulation (software)
MRN-NEEM	Multi-Region National–North American Electricity and Environment Model
NEEM	North American Electricity and Environment Model
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
RPS	renewable portfolio standard
RPS/N	RPS, implemented nationally (future)
RPS/R	RPS, implemented regionally (future)
RTO	Regional Transmission Operator
SSC	stakeholder steering committee
SMR	small modular reactor
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, 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. This report documents the third part of that follow-on study [earlier reports (Hadley 2013; Hadley and Gotham 2014) covered the first two parts].

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.

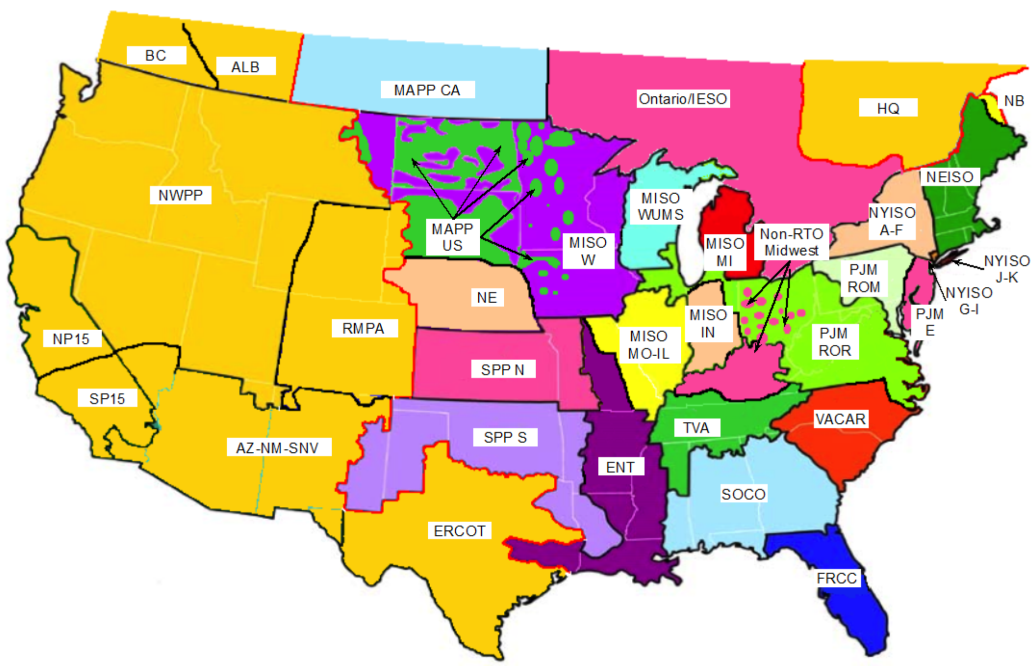

Fig. ES-1. Map of North American Electricity and Environment Model regions. (The Eastern Interconnection includes the multicolored, non-gold, regions).

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 Rivers 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 deploy	√	√	√		√	√		√
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/demand response/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 possible study topics was developed and ranked by the group in terms of relative priority (high, medium, low) and arranged such that the lower numbered (higher ranked) items in each category contributed to the later items within the same category (Table ES-4).

Table ES-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	Regional vs. national implementation of policies
11	Load growth sensitivities on resource mix and cost
12	Environmental policy sensitivity impacts
13	Technology sensitivity impacts

The first five topics were 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 2014). The third set of topics is covered in this report.

Topic 10: Regional versus national implementation of policies

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 on an electrical system 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"). Also, the CO_2/N future aggregated the EI into four defined regions where each had a maximum intermittency share of 35%, while the CO_2/R applied the intermittency limits to the seven smaller superregions. The second set (Futures 5 and 6) examined the implementation of national and regional RPSs, called RPS/N and RPS/R. The RPS/R future had transfer capacity and intermittency limits similar to those in the CO_2/R future. Thus, compliance with national policy goals was forced to occur primarily within each superregion, with little contribution from imports from another superregion. Implementing policy on a regional versus national level has implications for the location and type of resources used and the cost of meeting the load under the policy.

Carbon dioxide prices for the two CO_2 futures 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 (CO_2/N), and the resulting prices were also used for the regional implementation (CO_2/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. Generation levels in the Southwest and Midwest dropped under the regional implementation, with wind generation reduced significantly. Generation increased in the Southeast and PJM ROR* superregions. With the reduction in wind generation and increased generation from natural gas and coal, the regional implementation produced more CO_2 emissions. As a consequence, the CO_2/R future would have needed higher CO_2 prices in some areas of the EI to meet the reduction goals.

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 price had 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.

Topic 11: 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. Growth rates could vary year by year. While most of the futures started with the same growth rates for a specific region, they could be altered because the economic model MRN incorporated price elasticity to reduce demands as prices rose. In addition, the energy efficiency (EE)/demand response (DR) and CO_2+ futures included a 1% reduction in growth rates to represent the impact of EE programs. Each region could have a different growth rate, depending on its expected use patterns and economic growth. Some regions had flat to negative growth (e.g., PJM E and NEISO) based on their existing EE plans.

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. Load growth sensitivities were run in six different futures: the BAU, CO_2/N, CO_2/R, RPS/N, RPS/R, and nuclear resurgence (NUC). The first three included both high and low load growths, while the last three only evaluated high load growth 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 too involved and cumbersome to apply to each sensitivity, and sensitivities by definition are modest changes to one or a few inputs to better understand their influence. 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-2 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

*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.

amounts change roughly in line with the total percentage change, while coal and nuclear generation change little.

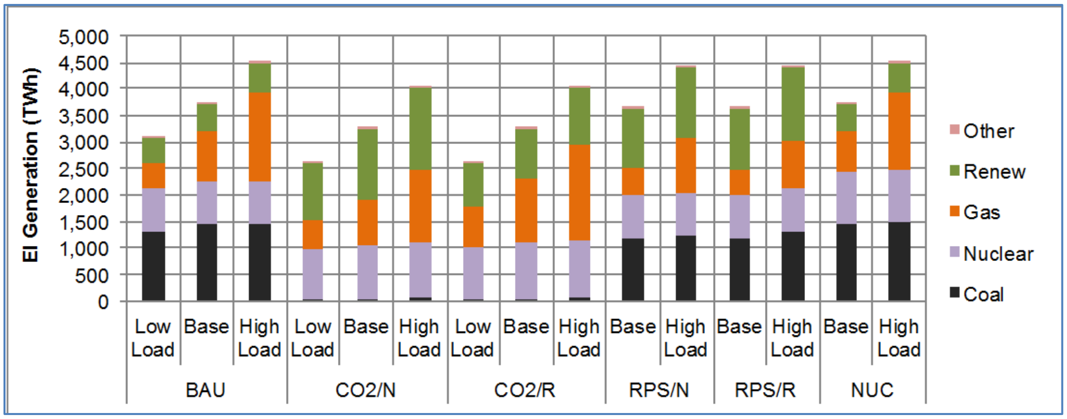

Fig. ES-2. Eastern Interconnection (EI) projected generation by technology in 2030 under different load growth scenarios.

Most regions had generation changes that roughly matched their proportionate change in demand, but a few had higher variations. The PJM regions had proportionately higher growth in the CO_2 futures because they were high importers from the Midwest and Southwest. Transmission between those regions was constrained a large portion of the time, so PJM had to generate most of the growth internally. Reductions in demand meant transmission capacity was freed up more often, allowing more exports. The Southwest faced the opposite issue because it generated large amounts for export. Increases in overall demand did not raise generation as much because exports could not grow. Cost changes tended to mirror generation changes but with some amplification because higher cost generation was the marginal amount added.

Topic 12: Environmental policy sensitivity impacts

High CO_2 costs greatly "decarbonized" the electric sector, especially post-2030. Lowering CO_2 prices by 20% lowered 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. Lowered nuclear costs by themselves had little effect on increasing nuclear share.

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 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-3). 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.

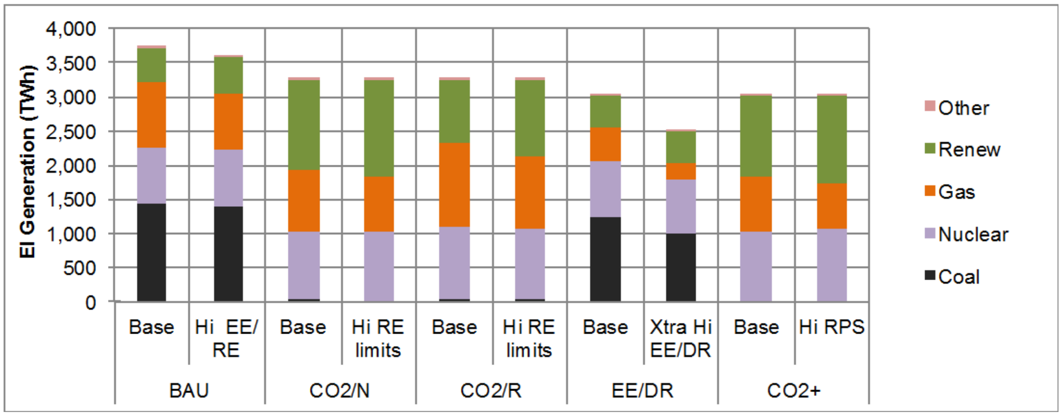

Fig. ES-3. Eastern Interconnection (EI) generation in 2030 by technology for increased environmental policy sensitivities.

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: 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. 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, 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 NUC base and the small modular reactor (SMR) sensitivity through 2030. There was 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 reflected both the lowered capital cost of new nuclear plants built in the cases and minor variations from modeling.

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 did not grow beyond the input amounts.

1. INTRODUCTION

Between 2010 and 2012 the Eastern Interconnection Planning Collaborative (EIPC) conducted a major long-term resource and transmission study of the Eastern Interconnection (EI). With guidance from a stakeholder steering committee (SSC) that included representatives from the Eastern Interconnection States' Planning Council (EISPC) among others, the project was conducted in two phases. The first was a 2015–2040 analysis that looked at a broad array of possible future scenarios, while the second focused on a more detailed examination of the grid in 2030. The studies provided a wealth of information on possible future generation, demand, and transmission alternatives; however, at the conclusion there were still unresolved questions and issues. 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 third part of that follow-on study [earlier reports (Hadley 2013; Hadley and Gotham 2014) covered the first two parts].

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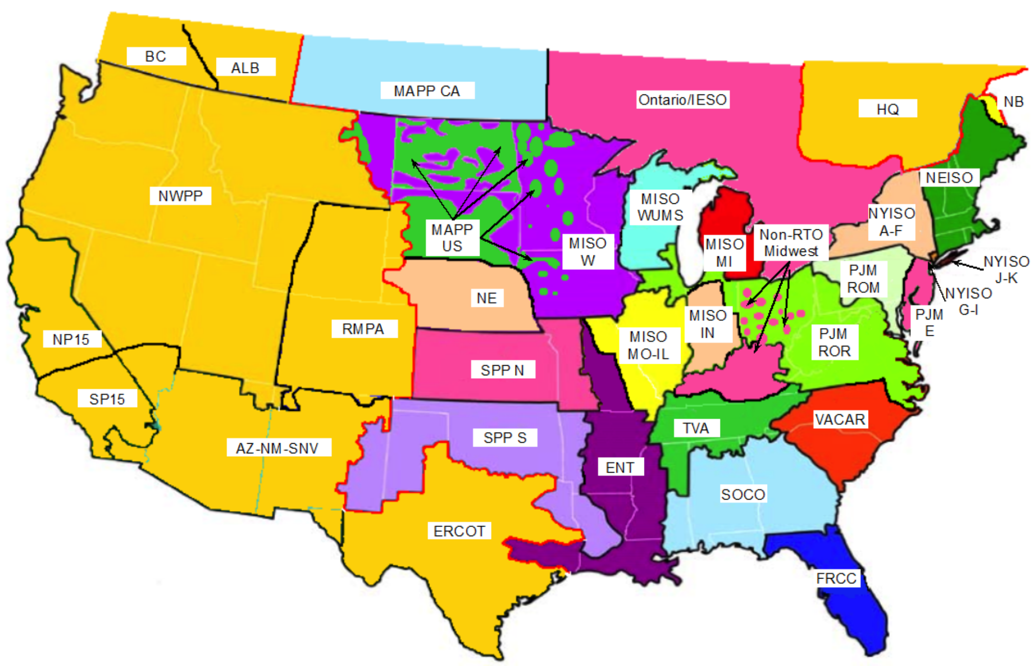

Fig. 1. Map of North American Electricity and Environmental Model regions. (The Eastern Interconnection includes the multicolored, non-gold, regions.)

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 (Regional Transmission Operator) 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
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The Phase 1 analysis used a capacity expansion model belonging to Charles Rivers 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). 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 or superregions 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 NUC 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.

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 deploy	√	√	√		√	√		√
Delay regulations	√							
CO2 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. 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 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, limiting them 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?

	Description
	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	Regional vs. national implementation of policies
11	Load growth sensitivities on resource mix and cost
12	Environmental policy sensitivity impacts
13	Technology sensitivity impacts

The first five topics were 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 2014). The third set of topics is covered in this report.

Section 2 (Topic 10) compares the results of two sets of futures from Phase 1 that examined the use of a regional approach to policy issues versus a national approach. The first set examined the impact of a CO_2 cost assigned to emissions; the second set examined the implementation of a national RPS. Implementing policy on a regional versus national level has implications for the location and type of resource used and the cost of meeting the load under the policy.

Sensitivities were run in many of the Phase 1 futures for high and/or low load growth. Section 3 (Topic 11) examines the effects of changing load growth in those futures. These effects include changes in the amount of energy transmitted between regions, changes in the generation from different sources, and the impact on costs.

A large number of the futures and sensitivities were defined to explore the effects of different environmental policies. The futures themselves looked at the impacts of CO_2 cost 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. Section 4 (Topic 12) looks at the effects of these modifications to the environmental policies in place in the different futures.

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. Natural gas price sensitivities are included in this category because a main component of gas prices is the continued feasibility of hydrofracturing and sufficient transportation infrastructure. In addition to gas prices, Section 5 (Topic 13) examines the impact of sensitivities surrounding the costs of renewable generation, advances in plug-in electric vehicles (PEVs), development of small modular reactors (SMRs), and offshore wind.

2. 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 section examines the impact of a regional implementation in comparison to a national implementation for the CO_2 cost and RPS futures.

2.1 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.

2.2 DEFINITION OF THE TWO POLICIES

2.2.1 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 Section 4.1, 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.

2.2.2 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).

2.3 METHOD OF ANALYSIS

This section 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 sections of this report, this section focuses on a comparison of the base cases with hardened transmission limits.

2.4 RESULTS

2.4.1 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. 2. Use of both coal and nuclear sources also increased under the regional implementation.

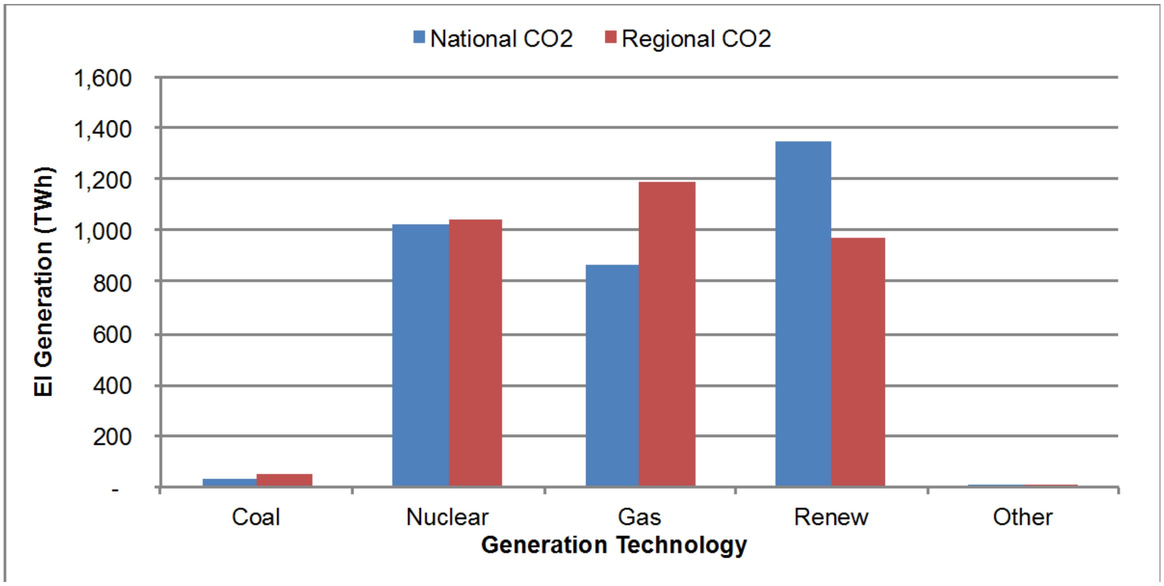

Fig. 2. Eastern Interconnection generation by type in 2030 under CO_2 futures.

As shown in Fig. 3, 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. 4. The regional implementation resulted in lower capital costs and operation and maintenance (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.

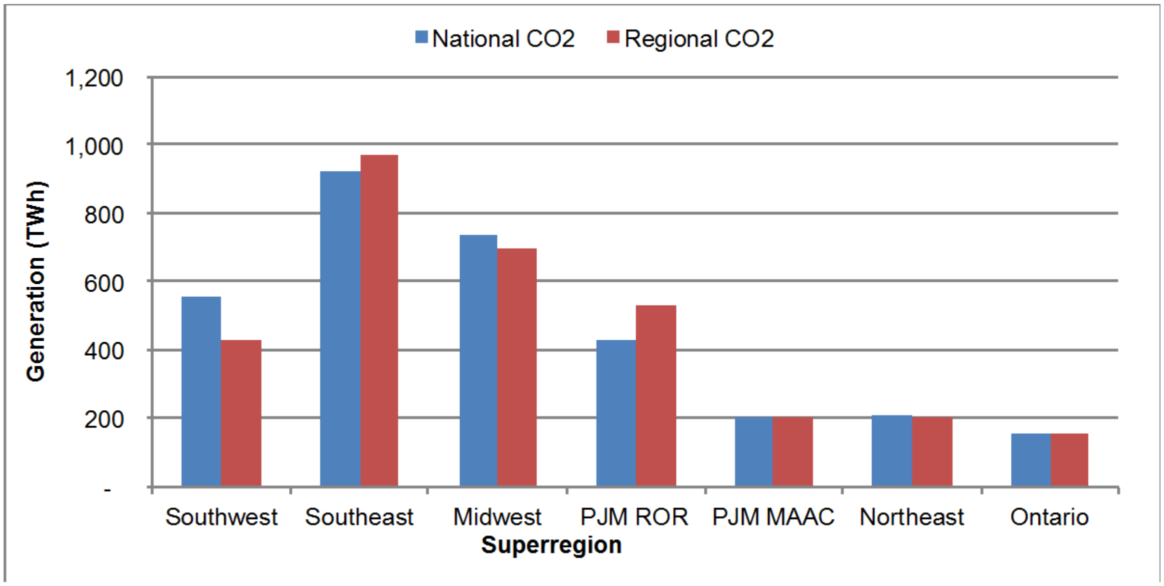

Fig. 3. Eastern Interconnection generation by superregion in 2030 under CO_2 prices.

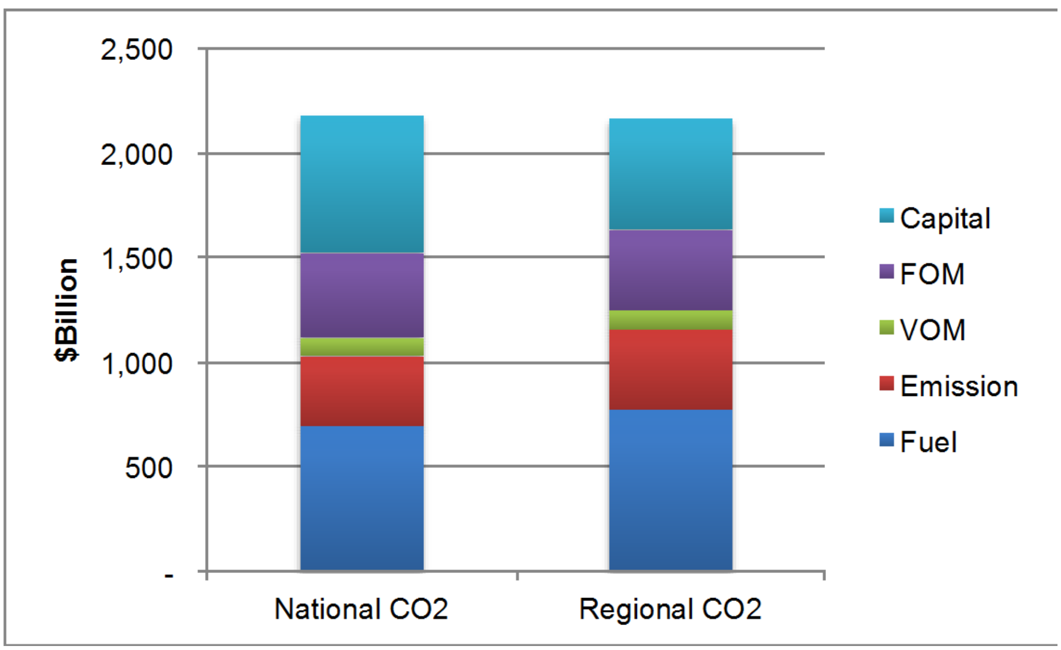

Fig. 4. Net present value costs, 2015–2030, under CO_2 prices.

2.4.2 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. 5. 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.

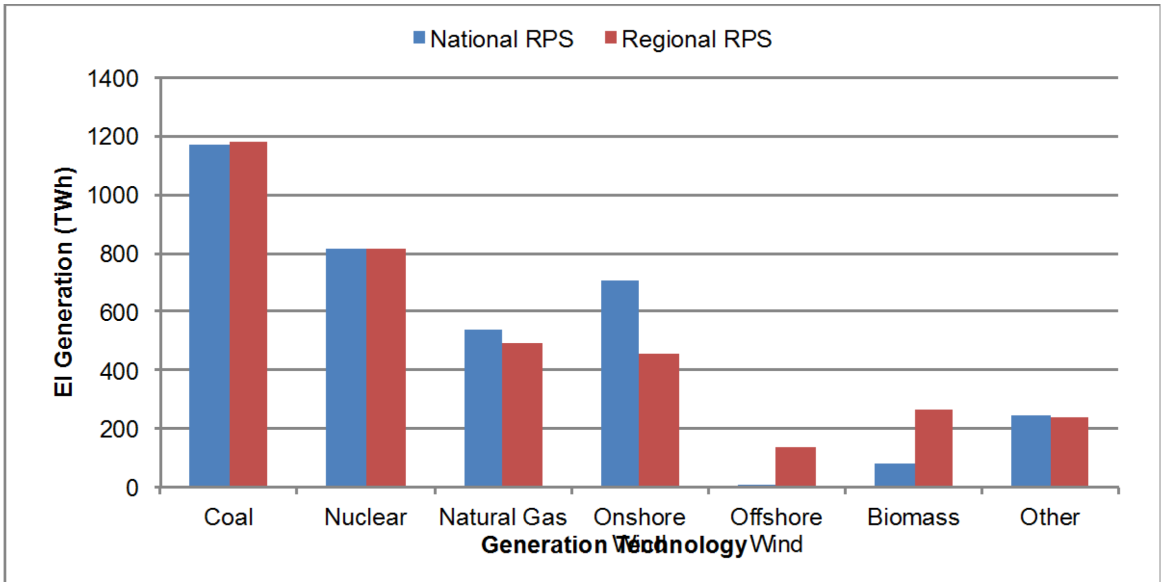

Fig. 5. Eastern Interconnection generation by type in 2030 under the renewable portfolio standard (RPS).

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 6 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. 7. 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.

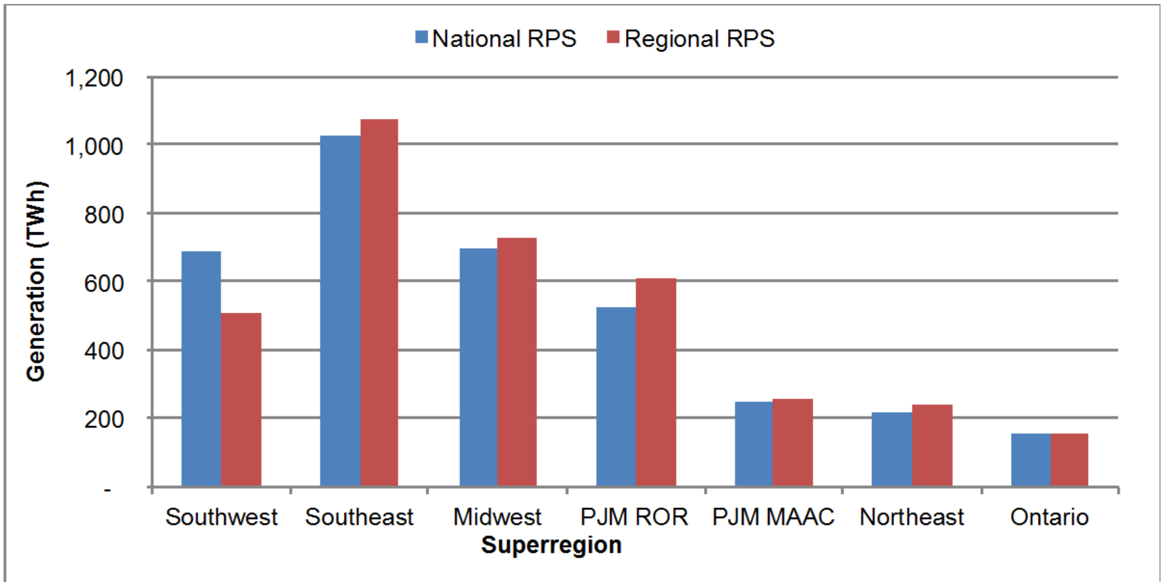

Fig. 6. Eastern Interconnection generation by superregion in 2030 under the renewable portfolio standard (RPS).

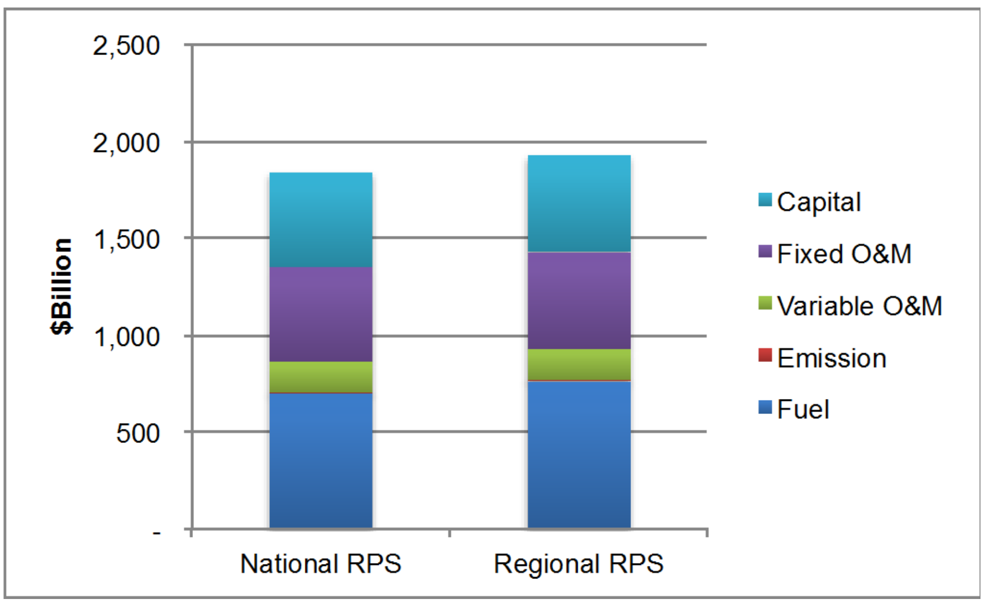

Fig. 7. Net present value costs, 2015–2030, under the renewable portfolio standard (RPS).

2.5 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.

3. LOAD GROWTH SENSITIVITIES

3.1 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 5. 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 5. 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 6). 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 6. 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.

3.2 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 energy efficiency and directly as demand response 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.

3.3 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.

3.3.1 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 8 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.

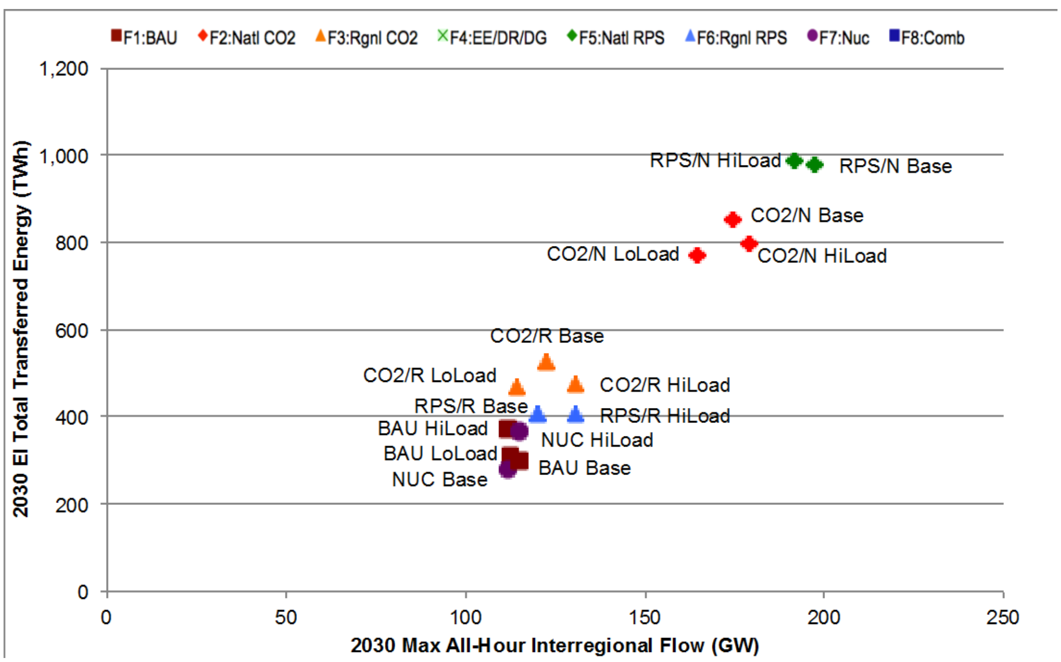

Fig. 8. Eastern Interconnection (EI) total interregional transfers (TWh) versus peak flow (GW) in 2030 under different load growth scenarios.

The nationally implemented RPS cases had the highest amount of flow, both peak and summed over the year (green diamonds in Fig. 8). 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.

3.3.2 Supply Mix Changes

Figure. 9 shows the EI generation amounts in 2030 by technology for the base case and sensitivities. As shown in Table 7, 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.

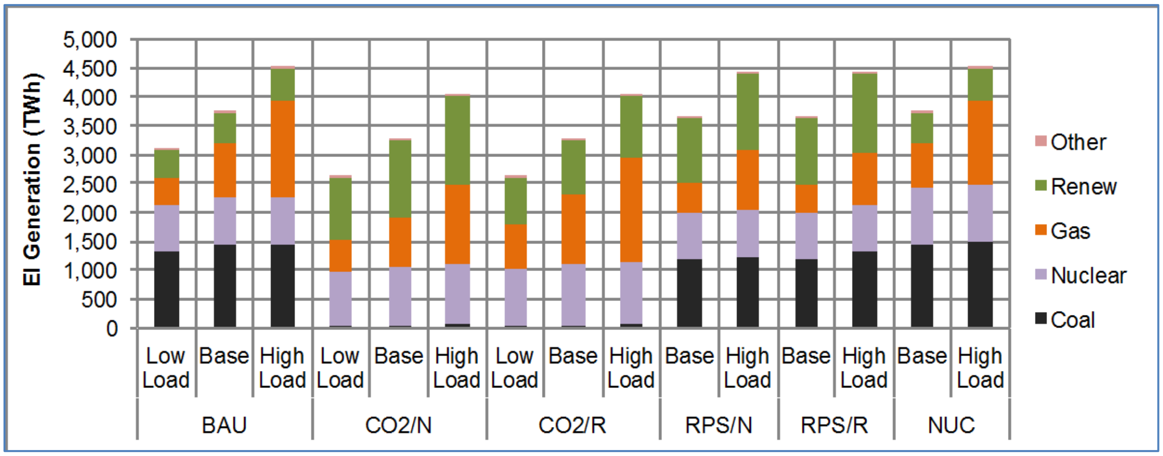

Fig. 9. Eastern Interconnection (EI) generation by technology in 2030 under different load growth scenarios.

Table 7. 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

3.3.3 Regional Changes

Most regions had similar changes in generation levels as demand increased or decreased (Fig. 10). 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 8, 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.

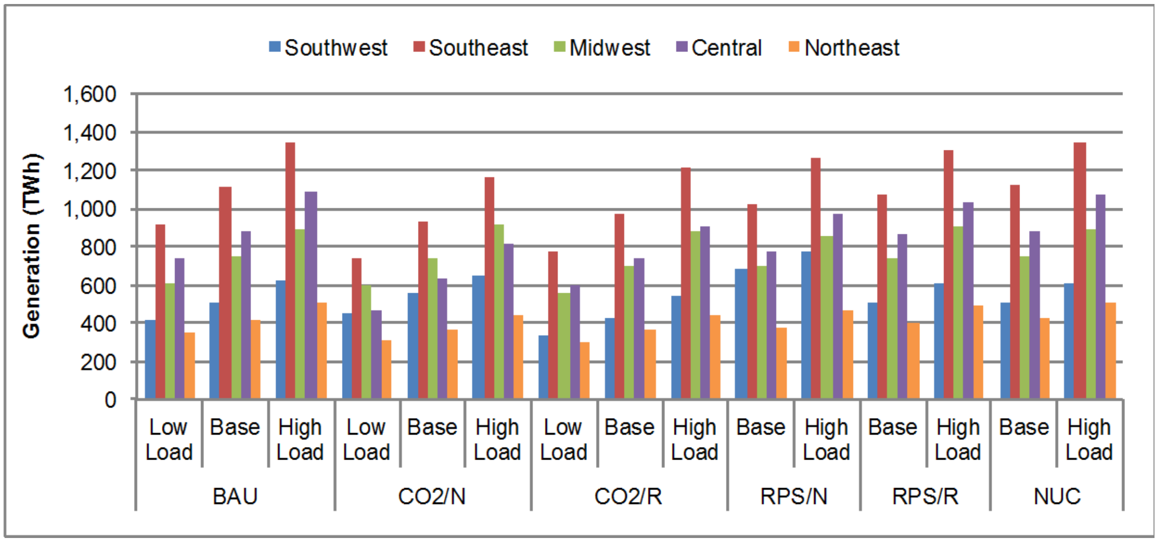

Fig. 10. Eastern Interconnection generation by territory in 2030 under different load growth scenarios.

Table 8. 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.

3.3.4 Regional Cost Changes

Costs of course increase with higher demands and decline with lower demands. Figure 11 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 9. 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.

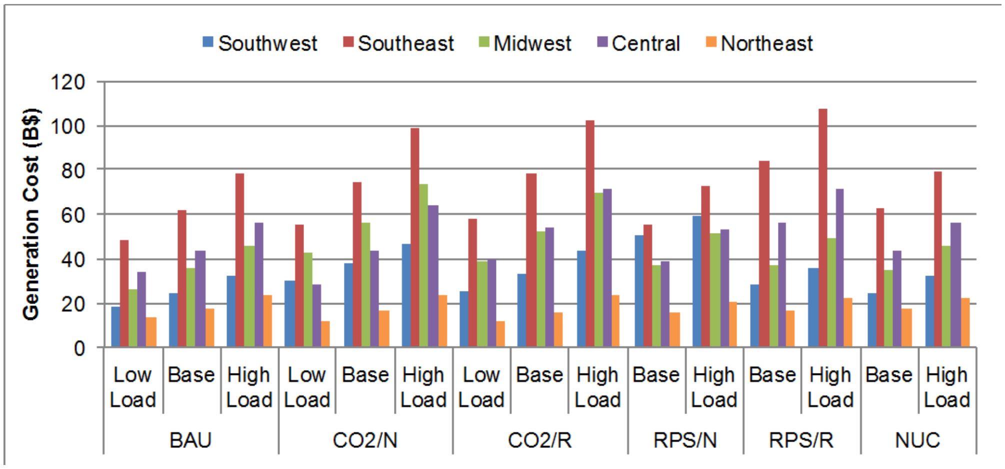

Fig. 11. Eastern Interconnection generation cost by territory in 2030 under different load growth scenarios.

Table 9. 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

3.4 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.

4. 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 section looks at the effects of these modifications to the environmental policies in place in the different futures.

4.1 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 10 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 10. 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 11 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. 12. 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 11. 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

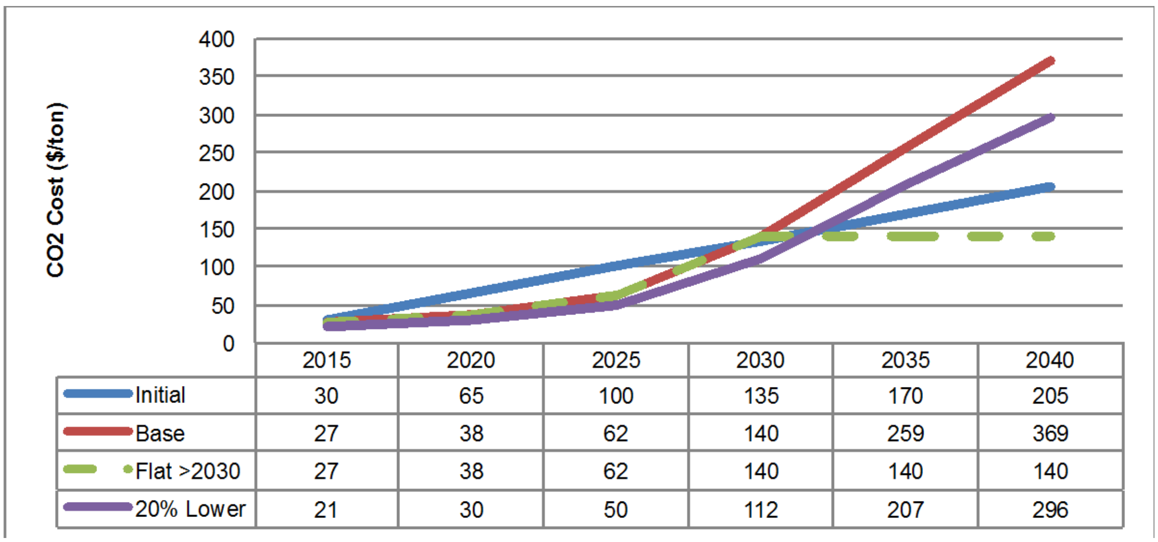

Fig. 12. Carbon dioxide price curves used in study.

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. 12). 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. 13) 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 14 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.

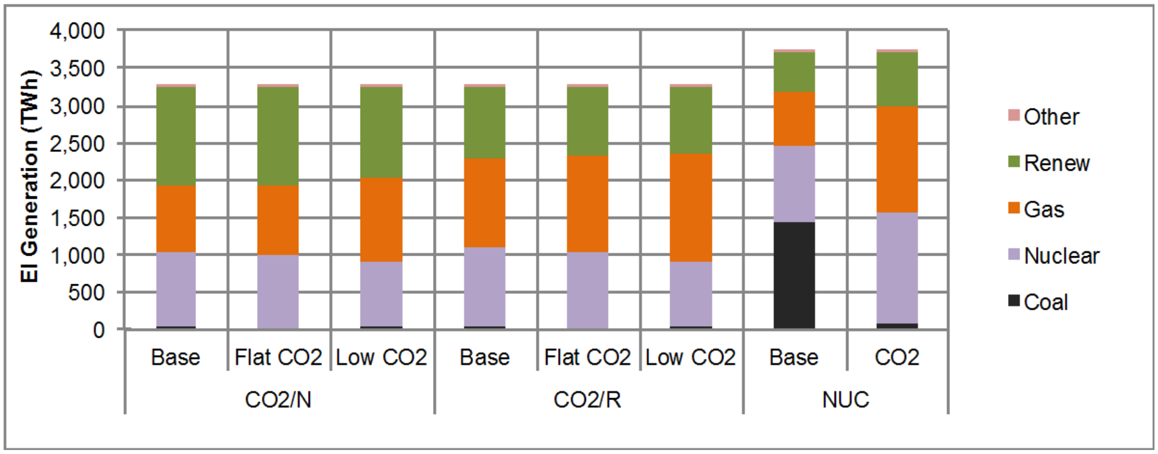

Fig. 13. Eastern Interconnection (EI) Generation in 2030 by technology for CO_2 price sensitivities.

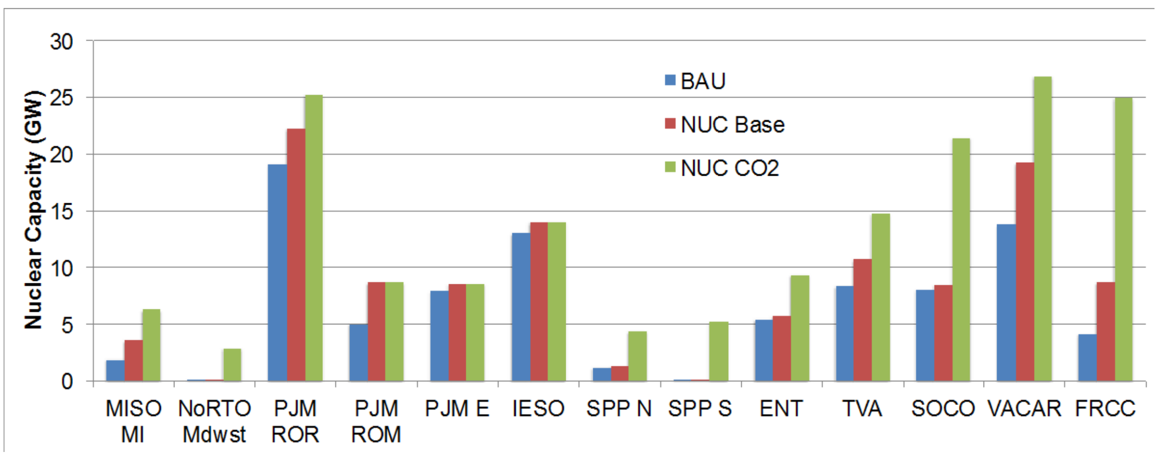

Fig. 14. Nuclear capacity in 2030 for the business as usual (BAU) and nuclear resurgence (NUC) futures and nuclear resurgence–carbon dioxide (NUC CO_2) sensitivity.

4.2 DELAYED IMPLEMENTATION OF ENVIRONMENTAL POLICIES

The base cases of the different futures included the expected US Environmental Protection Agency (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 Production Tax Credit (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 12).

Table 12. 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 timeframe 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-yrs	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.

4.3 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. 15). These both served to reduce the amount of gas-fired generation.

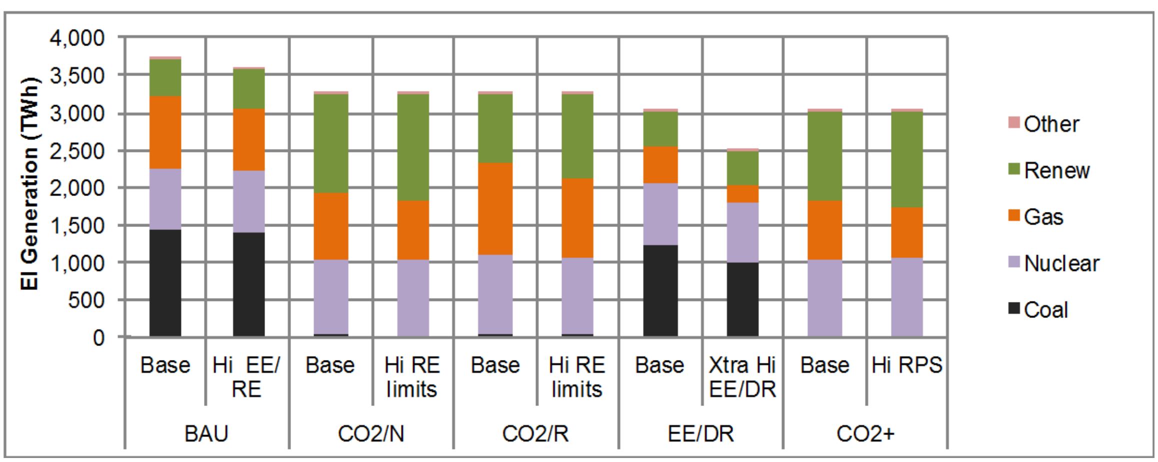

Fig. 15. Eastern Interconnection (EI) generation in 2030 by technology for increased environmental policy sensitivities.

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 distributed generation. 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 Federal Energy Regulatory Commission national assessment of DR (FERC 2009). The result of this sensitivity was a further decrease in coal- and gas-fired generation (Fig. 15).

4.4 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 13.

Table 13. 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. 16, 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 16, 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 14. 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.

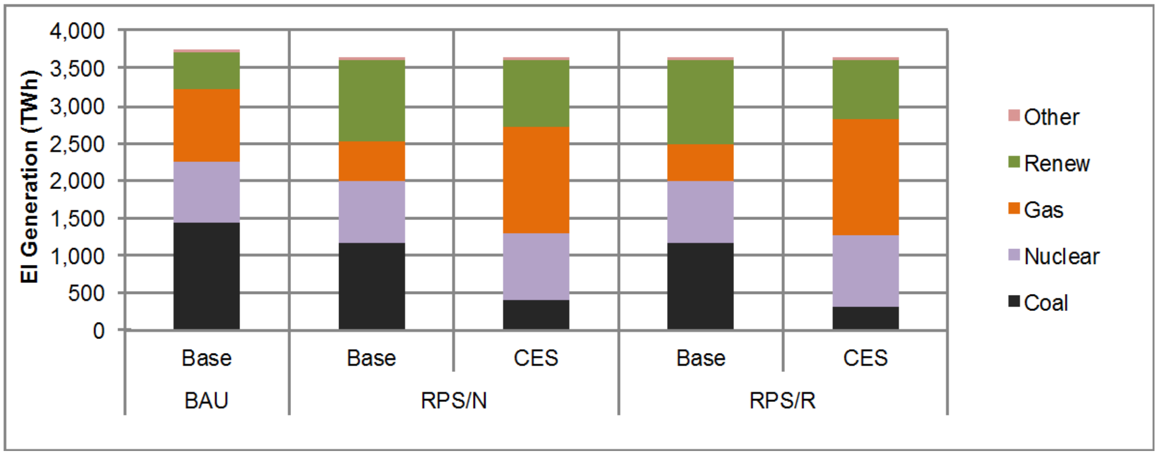

Fig. 16. Eastern Interconnection (EI) generation in 2030 by technology for Clean Energy Standard sensitivities.

Table 14. 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

4.5 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.

5. 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.

5.1 GAS PRICES

The base gas prices followed a trajectory based on the reference case from the Energy Information Administration's (EIA's) *Annual Energy Outlook (AEO) 2011 (early release)* (EIA 2011). 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 *AEO2010* (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 17 shows the price curves used for the base and sensitivities. It also shows the latest gas price forecast from the *AEO2014* (EIA 2014). The reference case in the *AEO2104* 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.

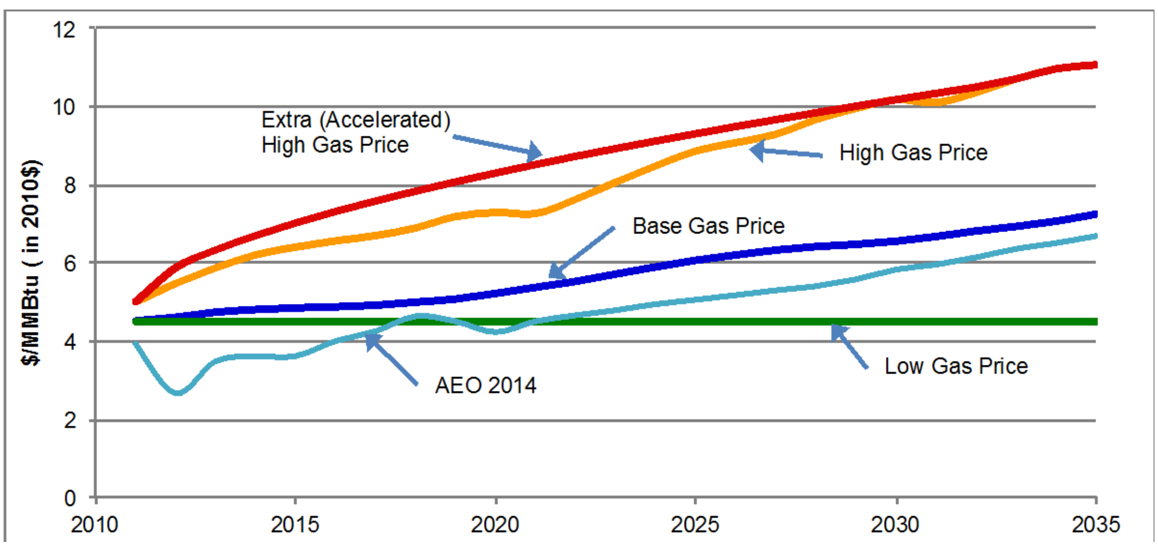

Fig. 17. Henry Hub gas price inputs to the MRN-NEEM model.

Five futures included gas price sensitivities. The BAU scenario included the high gas price and extra high gas price curves from Fig. 17 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. 18. In the BAU future with high gas prices coal retirements decrease and new coal and wind capacity is constructed. Fewer CC plants and combustion turbines (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.

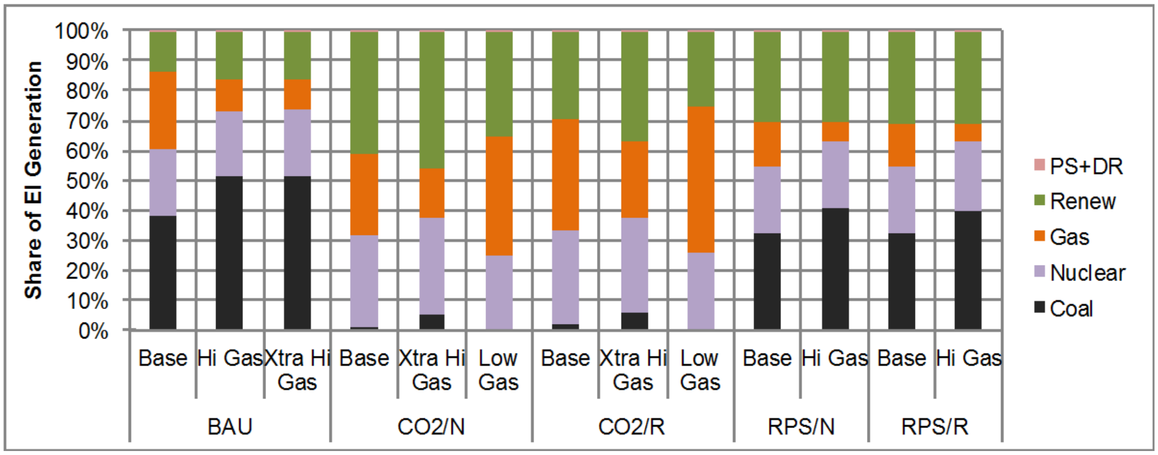

Fig. 18. Eastern Interconnection (EI) generation production share by technology for gas price sensitivities.

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 Section 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.

5.2 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. 19, there is a small but noticeable increase in renewable generation with the lower costs. Table 15 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.

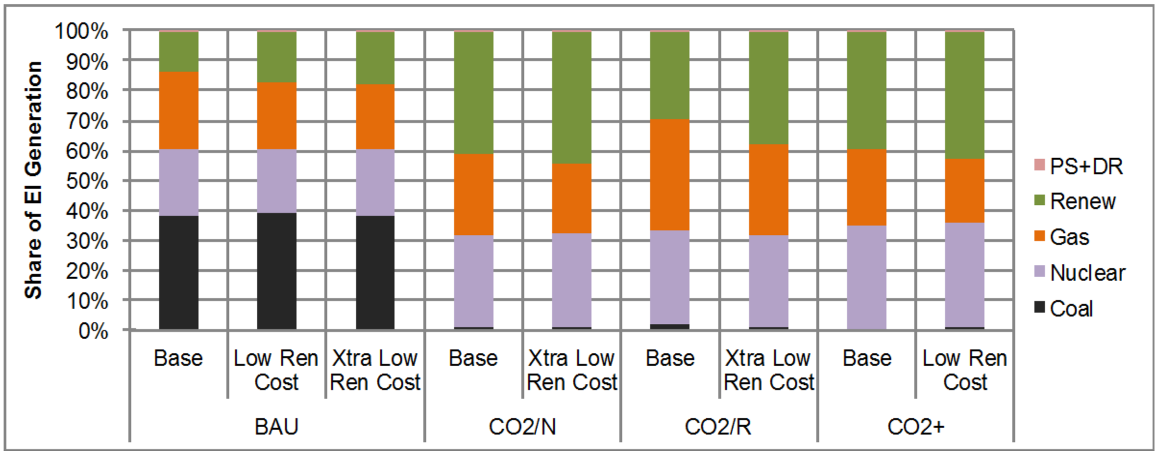

Fig. 19. Eastern Interconnection (EI) generation share by technology for renewable cost sensitivities.

Table 15. 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

5.3 PLUG-IN ELECTRIC VEHICLE ADVANCES

The electricity demand from a small number of PEVs was built into the base demand assumptions because demand was largely from the EIA *AEO2011* 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 20 is a chart of the PEV fleet size used in the analyses. The base case amount is from the *AEO2011* 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.

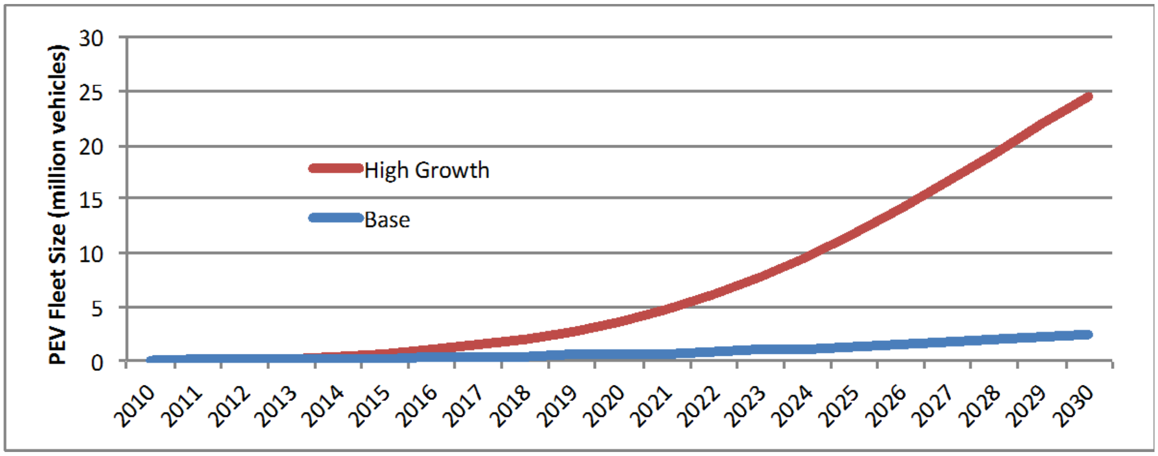

Fig. 20. Projected plug-in electric vehicle (PEV) quantities in the Eastern Interconnection.

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 21 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).

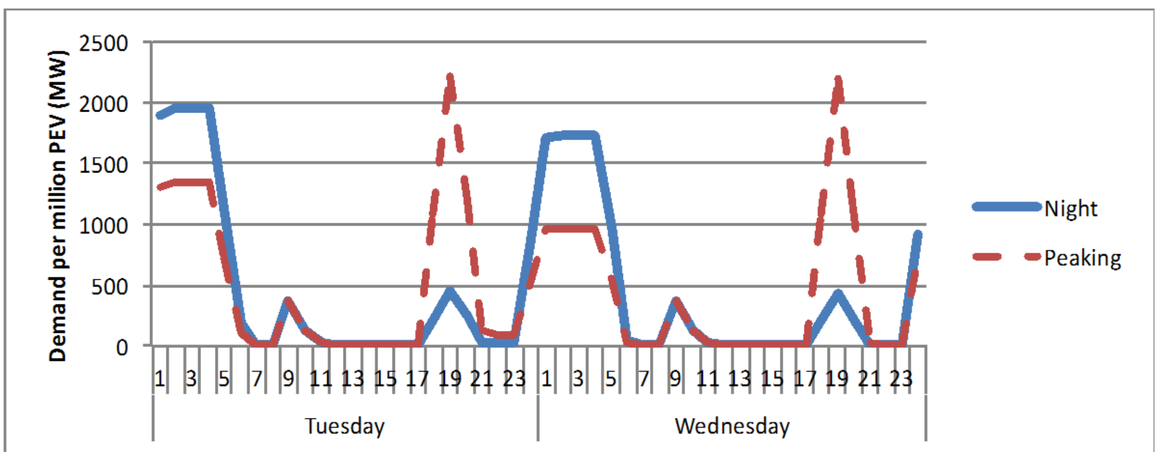

Fig. 21. Hourly demands from 1 million plug-in electric vehicles (PEVs) under the night and peaking demand cycles.

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. 22. 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.

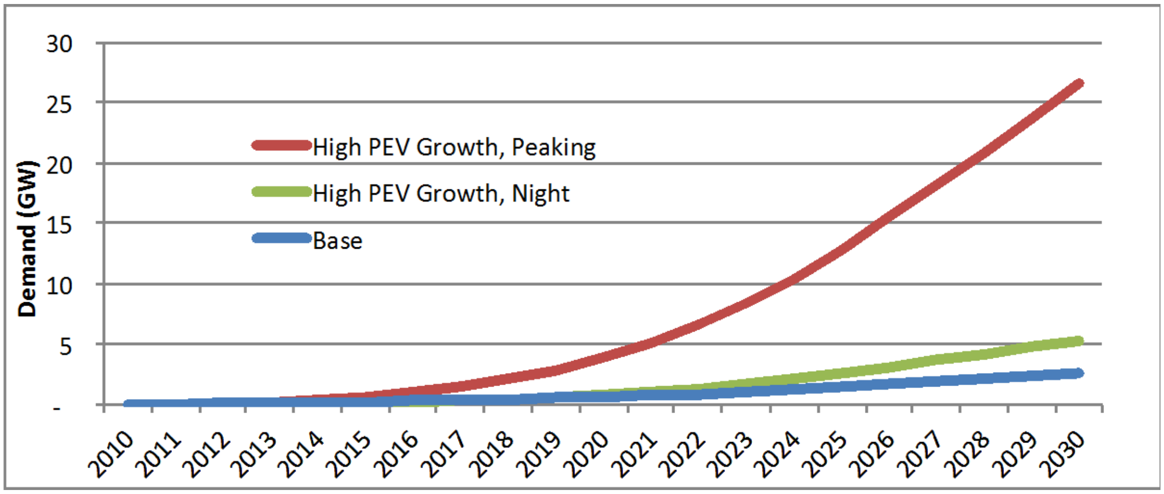

Fig. 22. Peak demand increases in the Eastern Interconnection due to base and high plug-in electric vehicle (PEV) growth.

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. 23), 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. Fig. 23 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. 24 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. 24, renewable capacity was added in the PEV charging sensitivity over and above what was added in the base RPS futures.

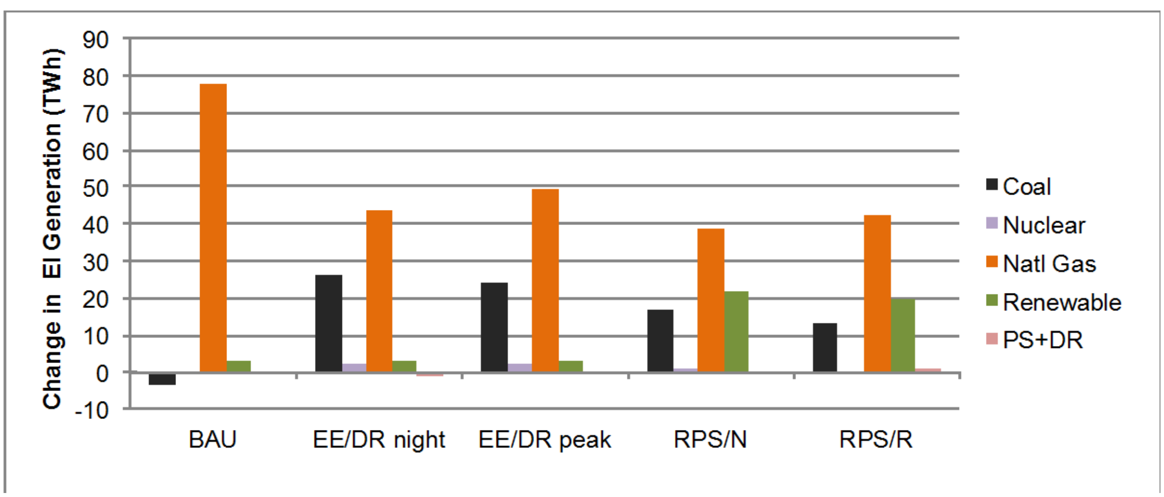

Fig. 23. Changes in Eastern Interconnection (EI) generation between the base scenario (BAU) and plug-in electric vehicle (PEV) sensitivity for three futures. The energy efficiency/demand response (EE/DR) future had two sensitivities: one with more PEV charging at peak times and one with charging at night (off-peak).

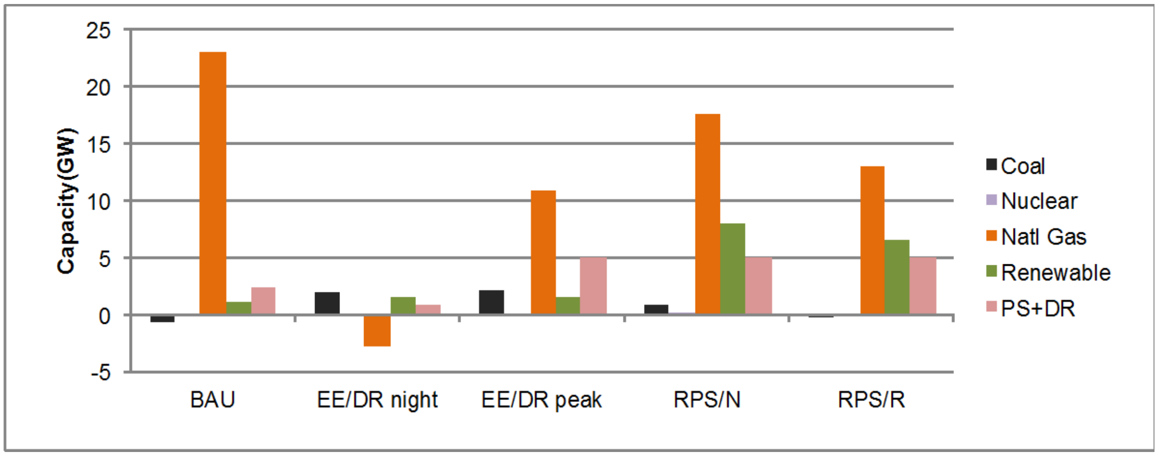

Fig. 24. Capacity changes between the base scenario (BAU) and plug-in electric vehicle (PEV) sensitivity for three futures. The energy efficiency/demand response (EE/DR) future had two sensitivities: one with more PEV charging at peak times and one with charging at night (off-peak).

5.4 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 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 16.

Table 16. 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.

5.5 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 17 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 17. 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

5.6 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, photovoltaic, 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.

6. REPORT CONCLUSIONS

This is the third of three reports exploring the results from a 3-year EIPC transmission study. (A fourth report will be developed in conjunction with Navigant that covers some of the main changes in the input parameters since the study and distributed solar PV implementation details. It will also consolidate the results from these three reports all into a single report.) The reports have enabled further insights into the results. This report in particular has helped document results that were of crucial interest during Phase 1 of the study: national versus regional implementation, effects of demand growth rates, environmental policy variations, and technology improvements or delays.

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APPENDIX. NATIONAL VERSUS REGIONAL FUTURE REGION-SPECIFIC RESULTS

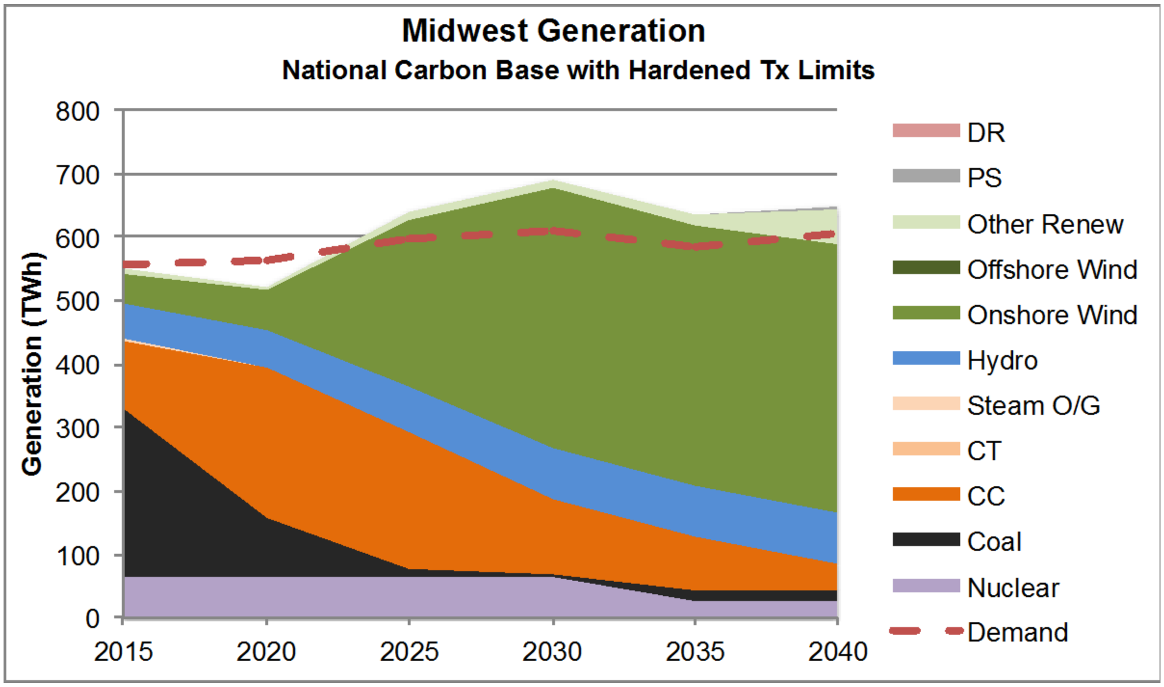

Fig. A-1. Midwest generation over study period in the CO_2/N future

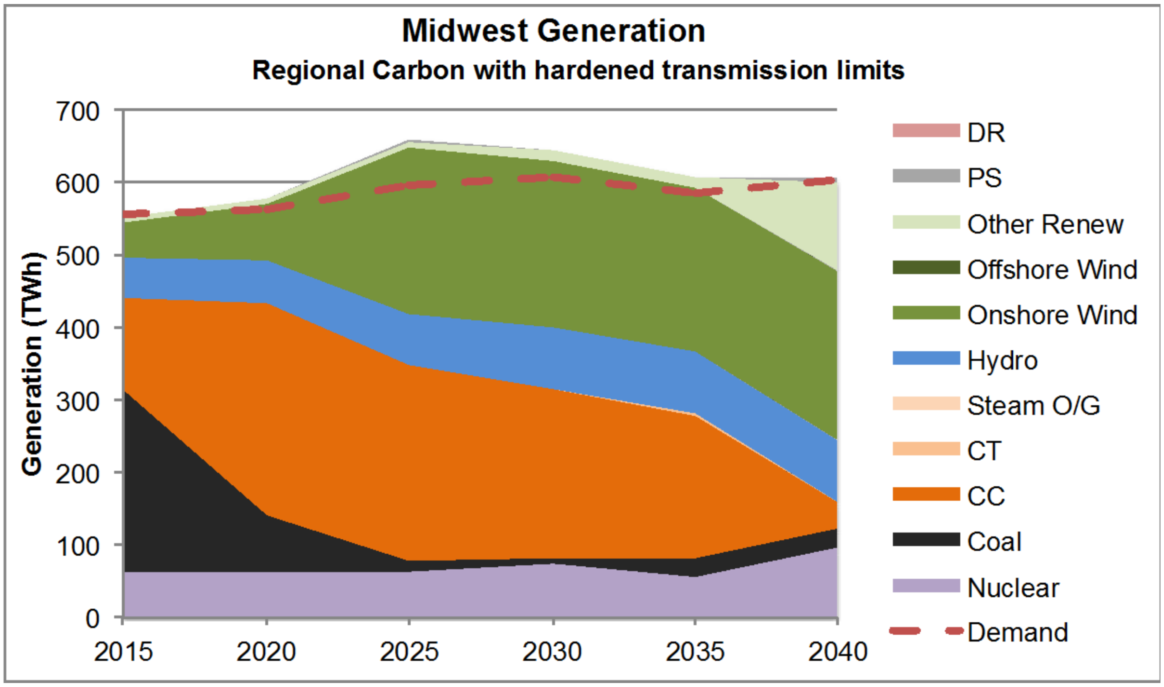

Fig. A-2. Midwest generation over study period in the CO_2/R future

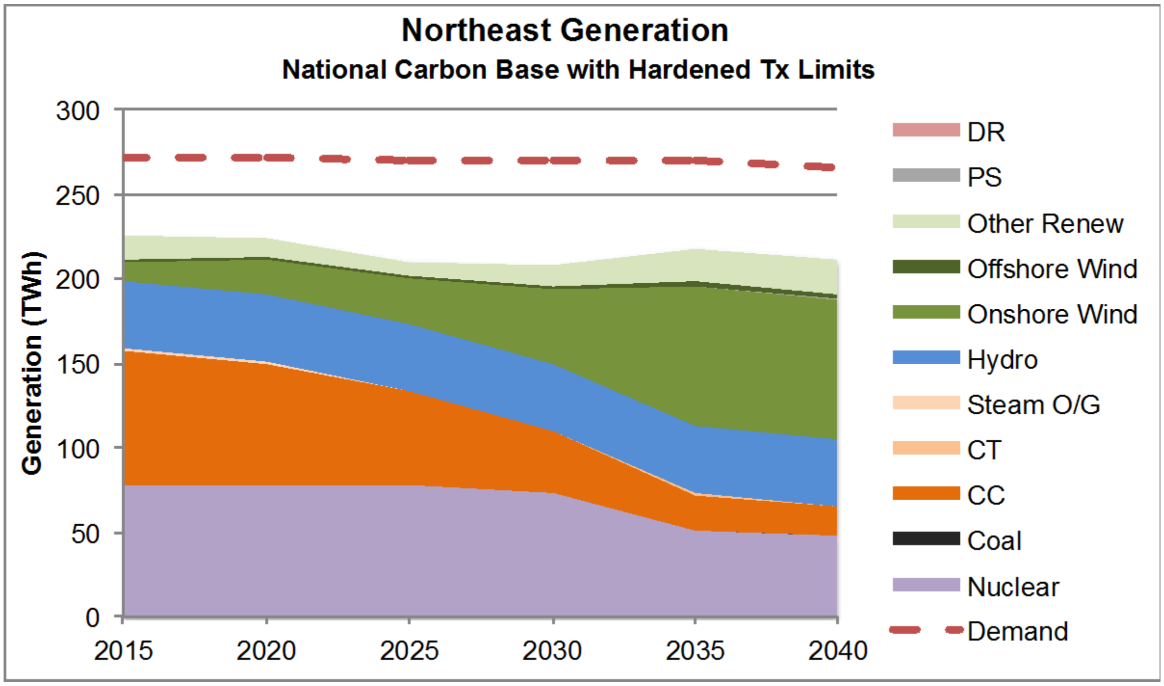

Fig. A-3. Northeast generation over study period in the CO_2/N future

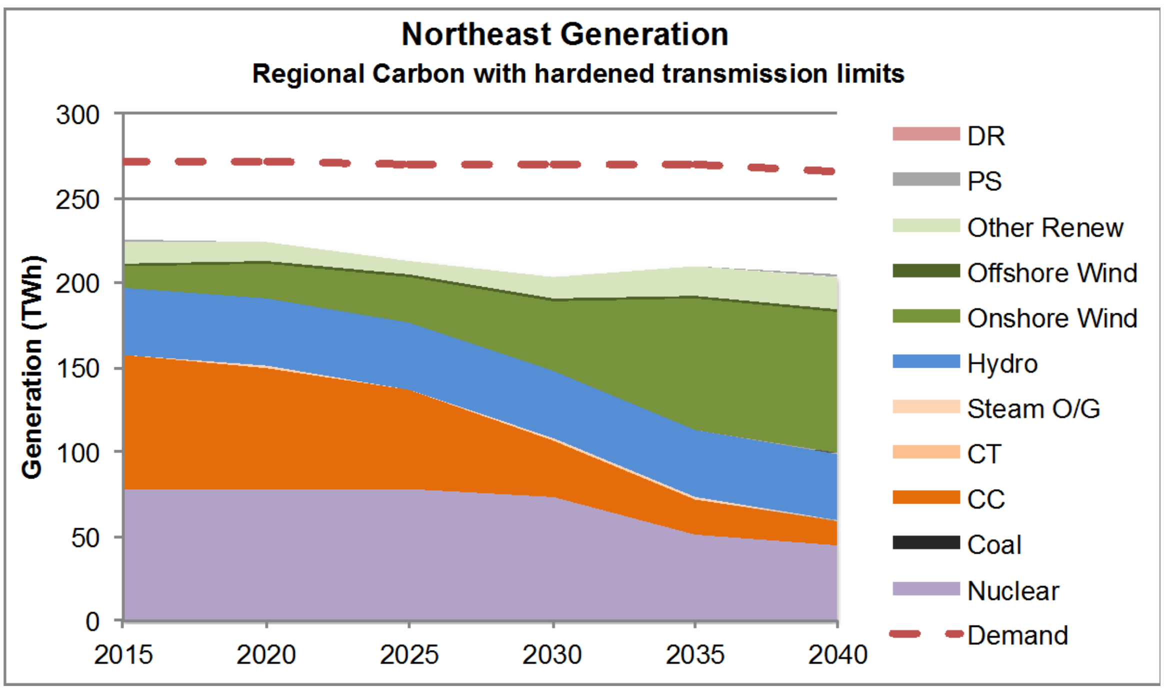

Fig. A-4. Northeast generation over study period in the CO_2/R future

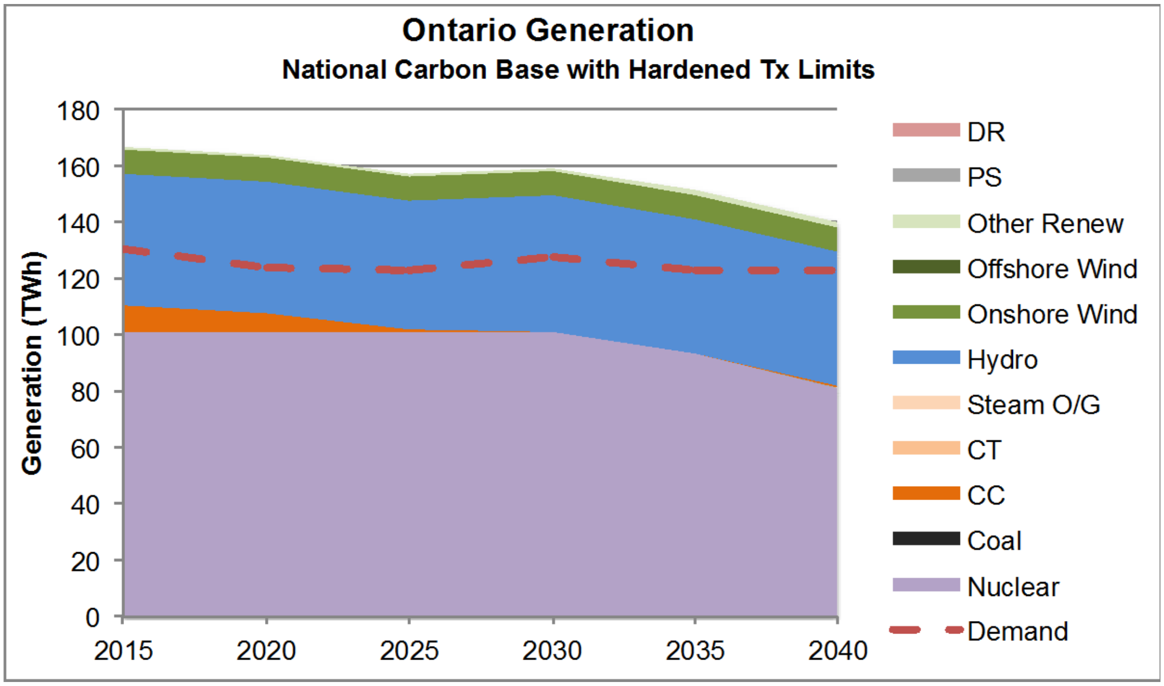

Fig. A-5. Ontario generation over study period in the CO_2/N future

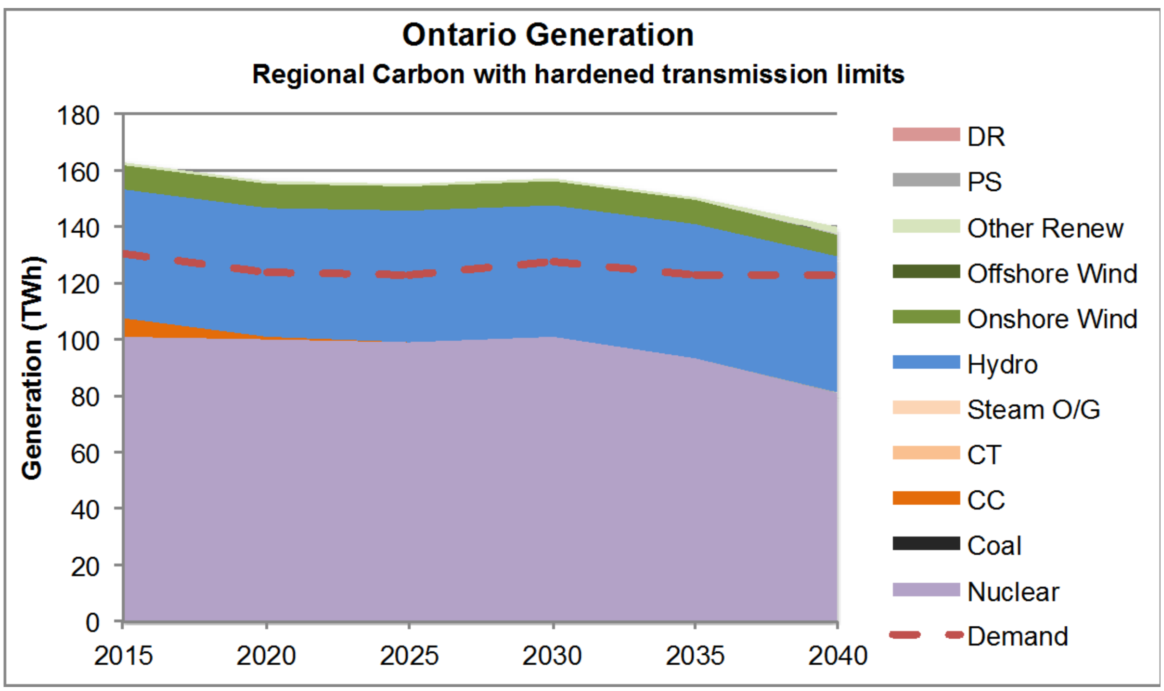

Fig. A-6. Ontario generation over study period in the CO_2/R future

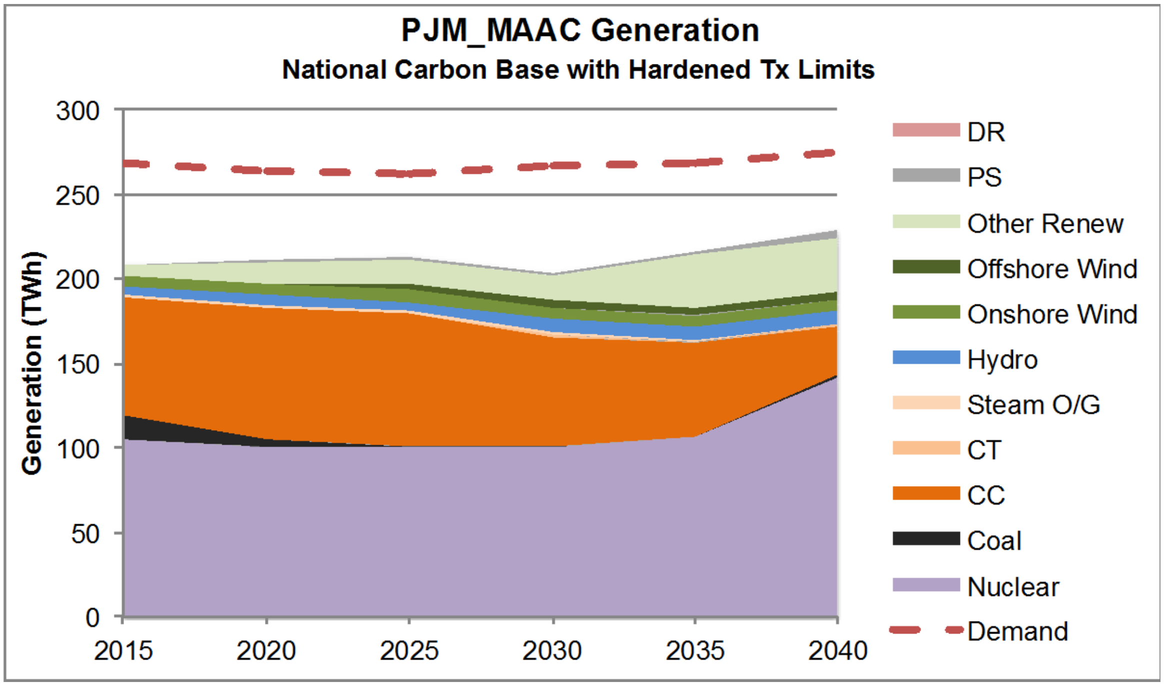

Fig. A-7. PJM MAAC generation over study period in the CO_2/N future

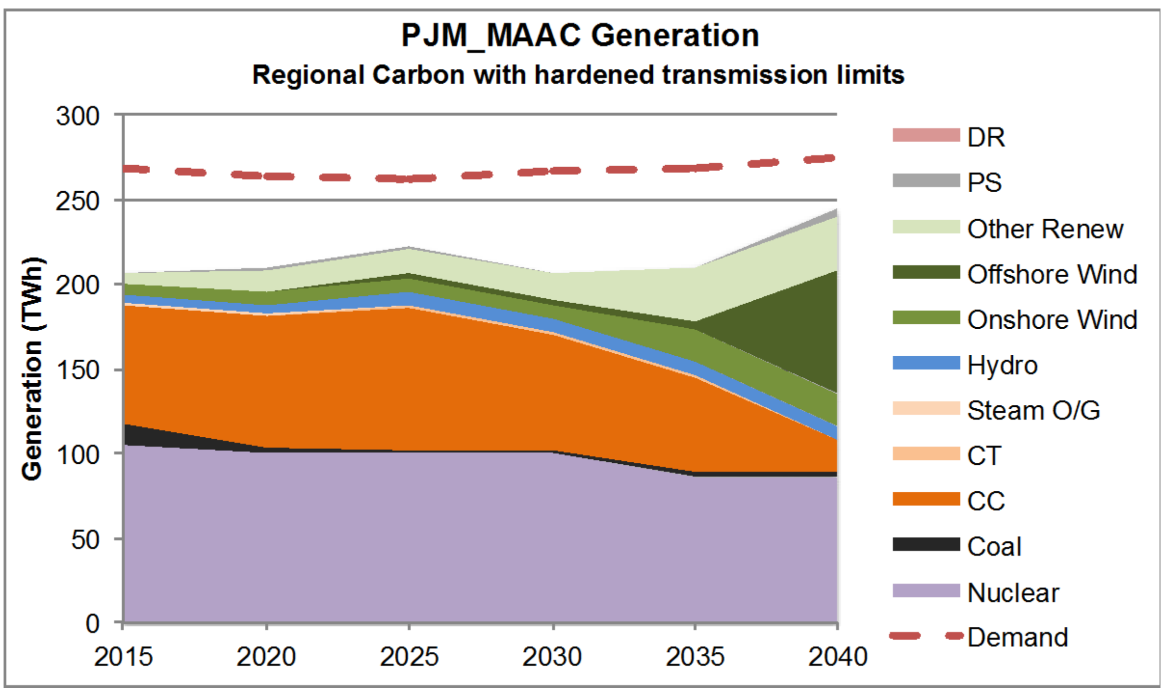

Fig. A-8. PJM MAAC generation over study period in the CO_2/R future

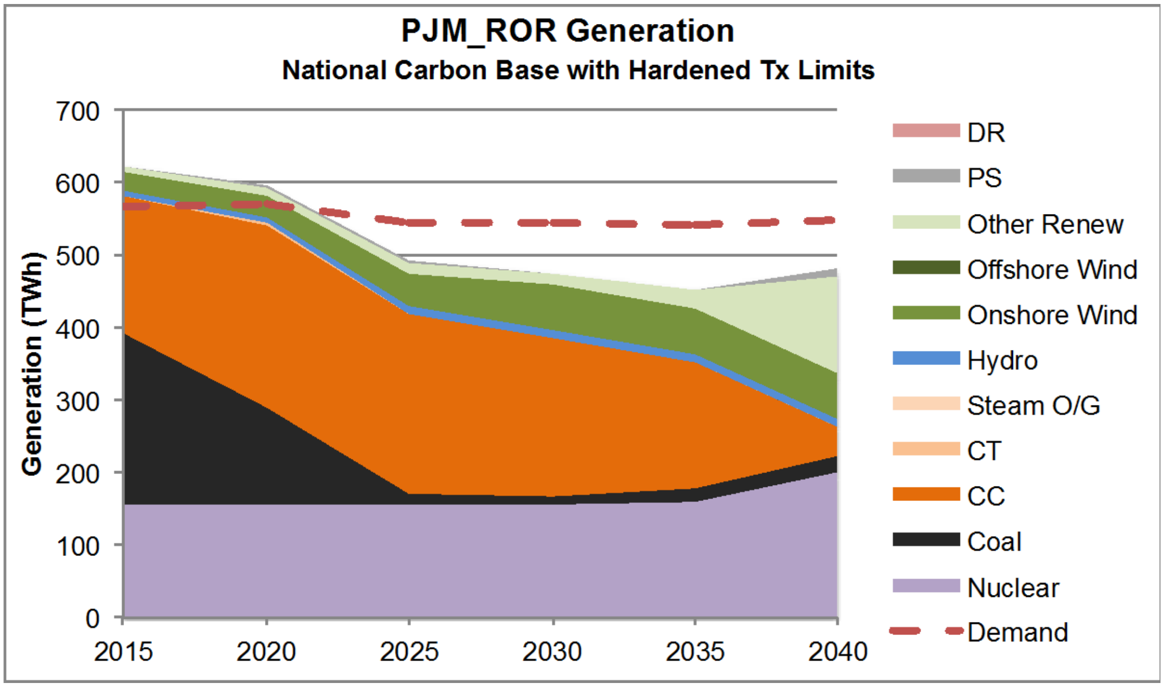

Fig. A-9. PJM ROR generation over study period in the CO_2/N future

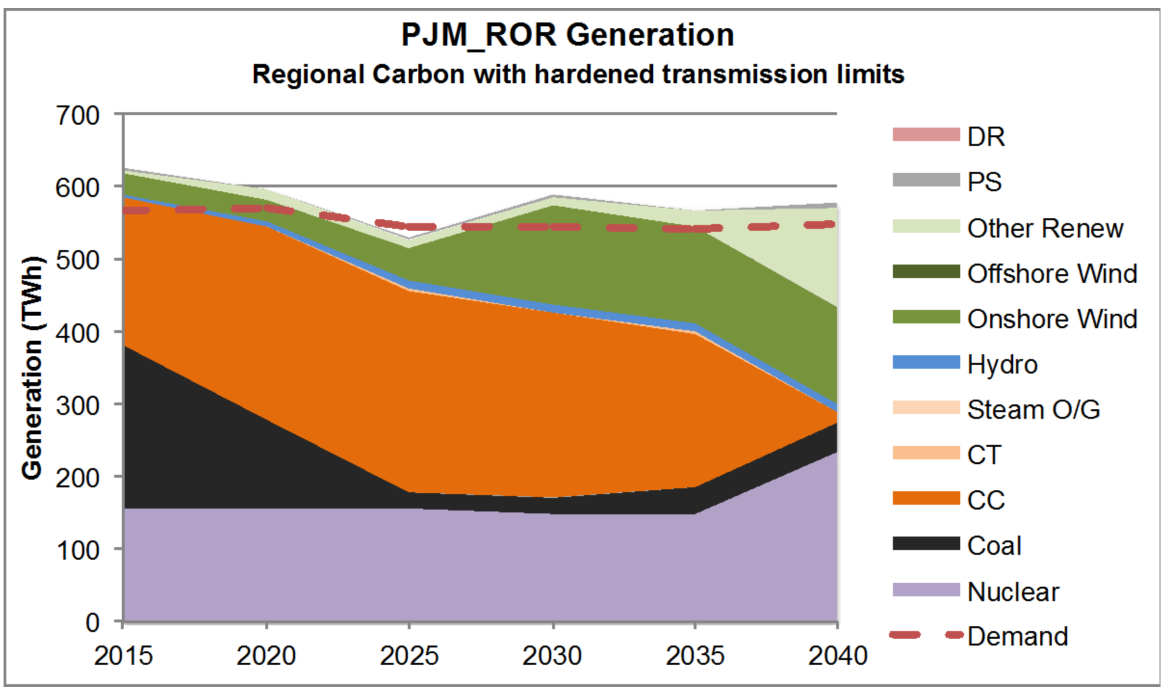

Fig. A-10. PJM ROR generation over study period in the CO_2/R future

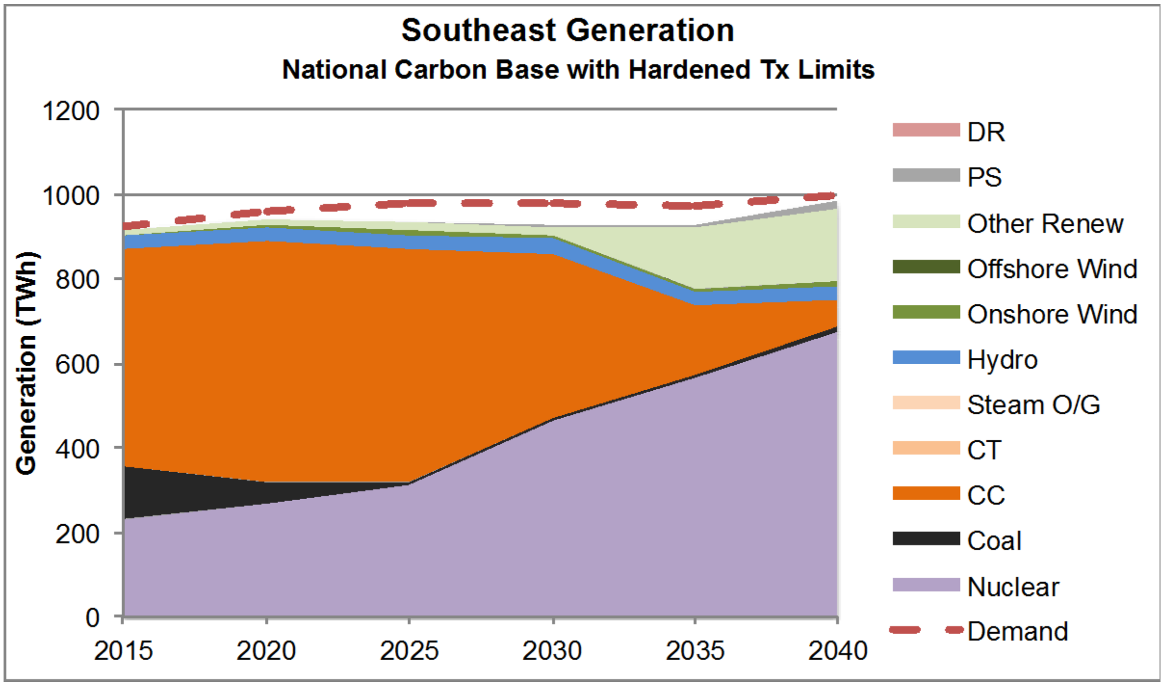

Fig. A-11. Southeast generation over study period in the CO_2/N future

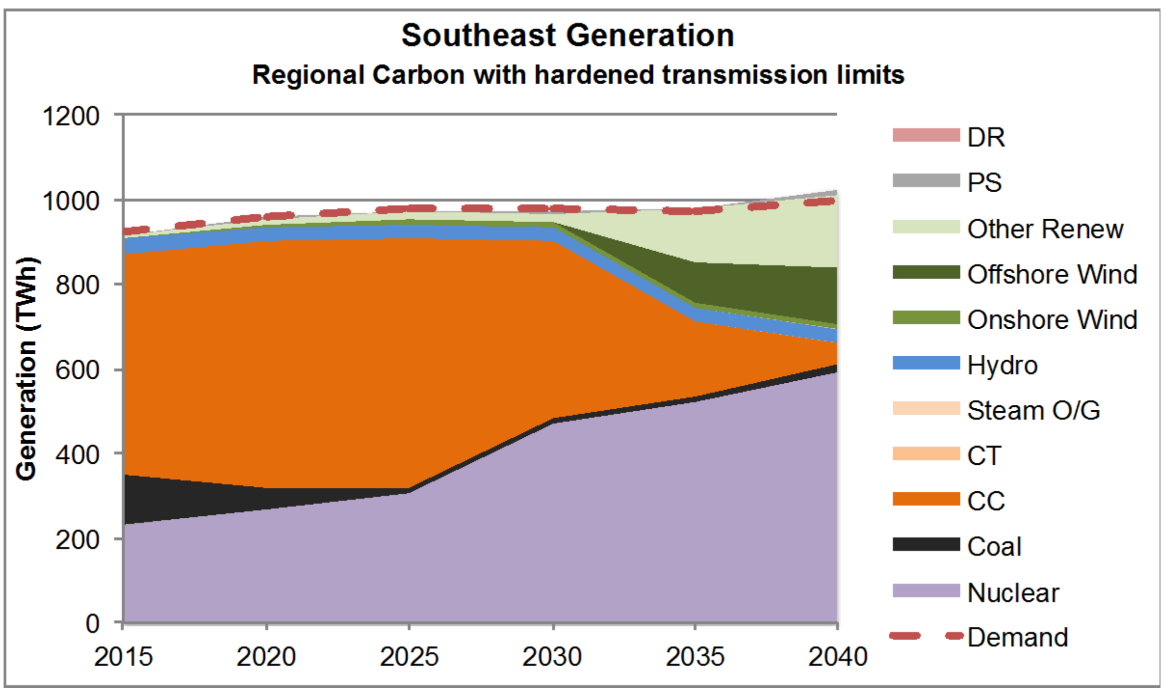

Fig. A-12. Southeast generation over study period in the CO_2/R future

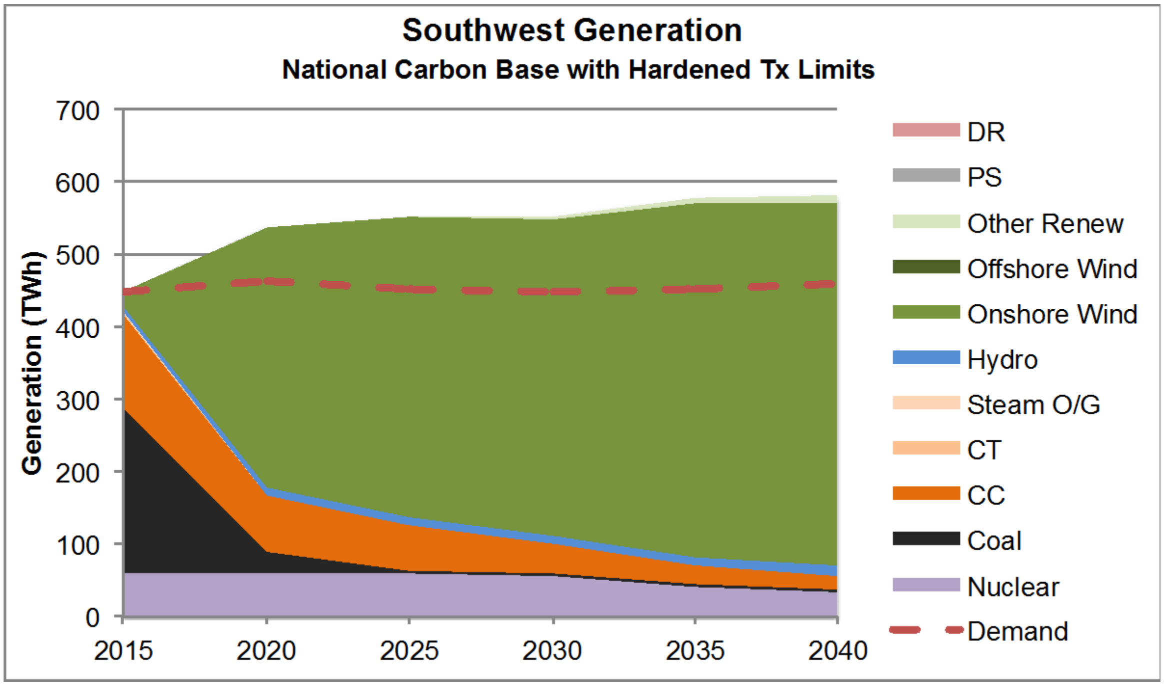

Fig. A-13. Southwest generation over study period in the CO_2/N future

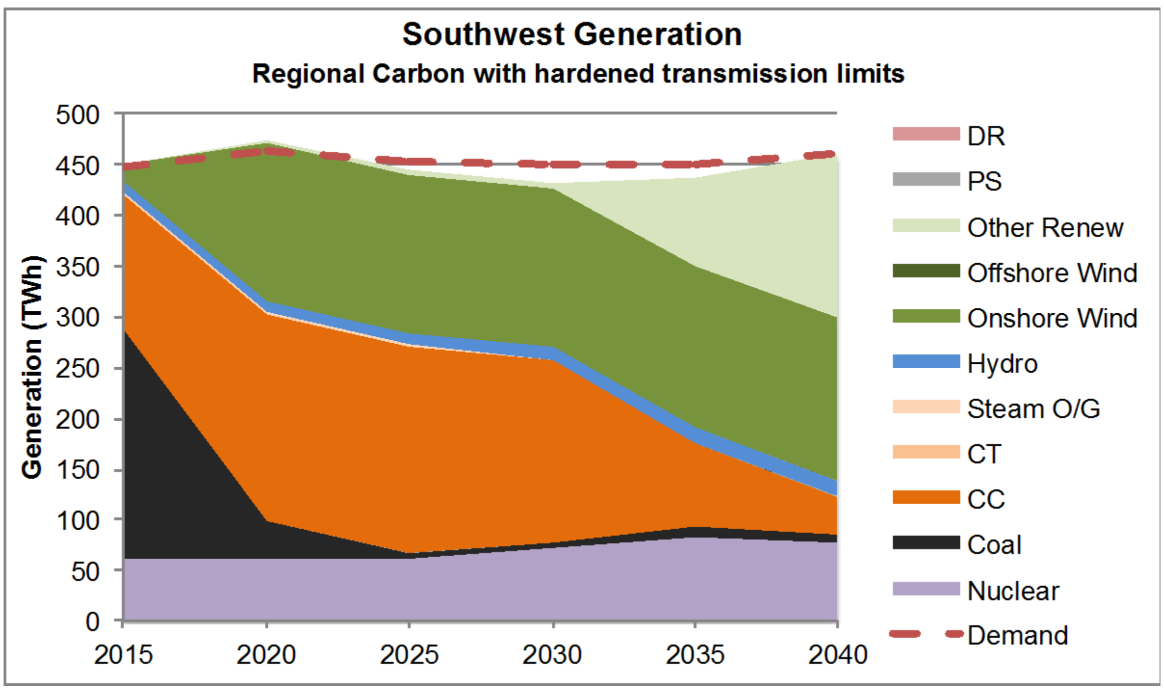

Fig. A-14. Southwest generation over study period in the CO_2/R future

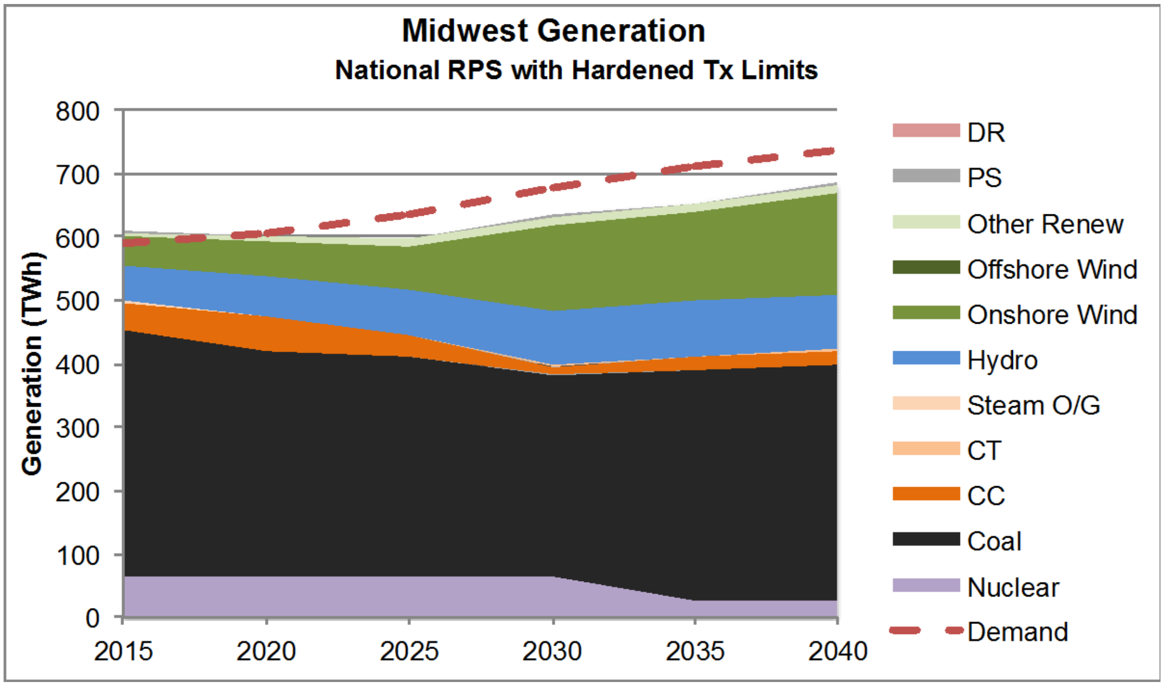

Fig. A-15. Midwest generation over study period in the RPS/N future

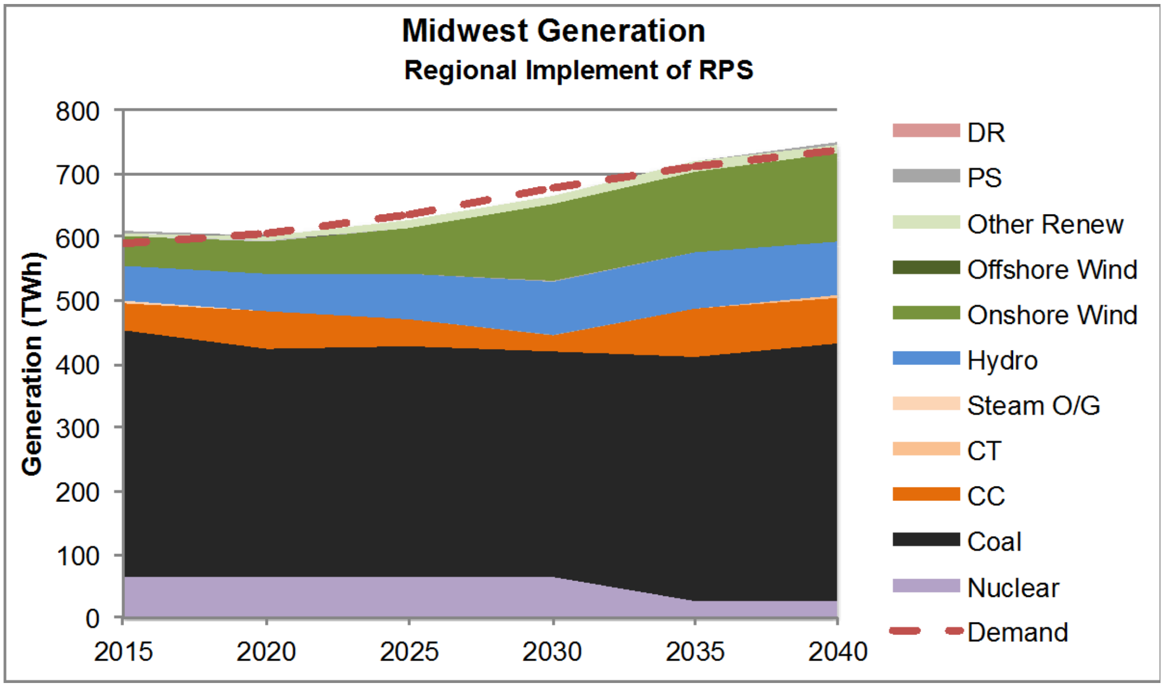

Fig. A-16. Midwest generation over study period in the RPS/R future

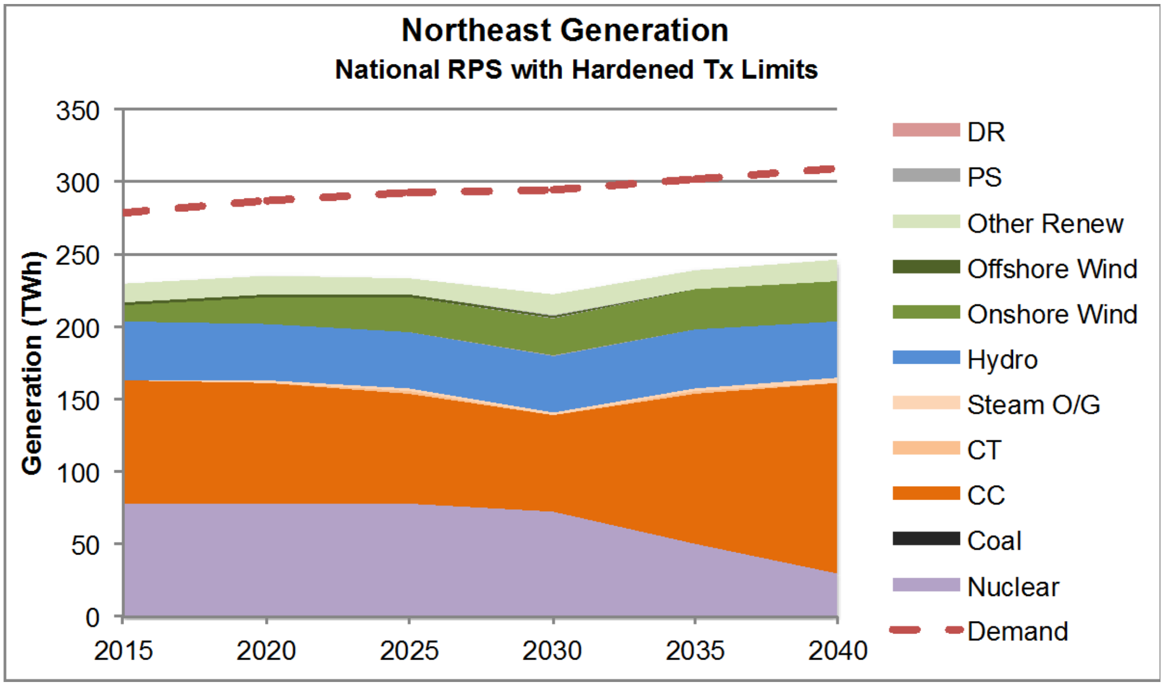

Fig. A-17. Northeast generation over study period in the RPS/N future

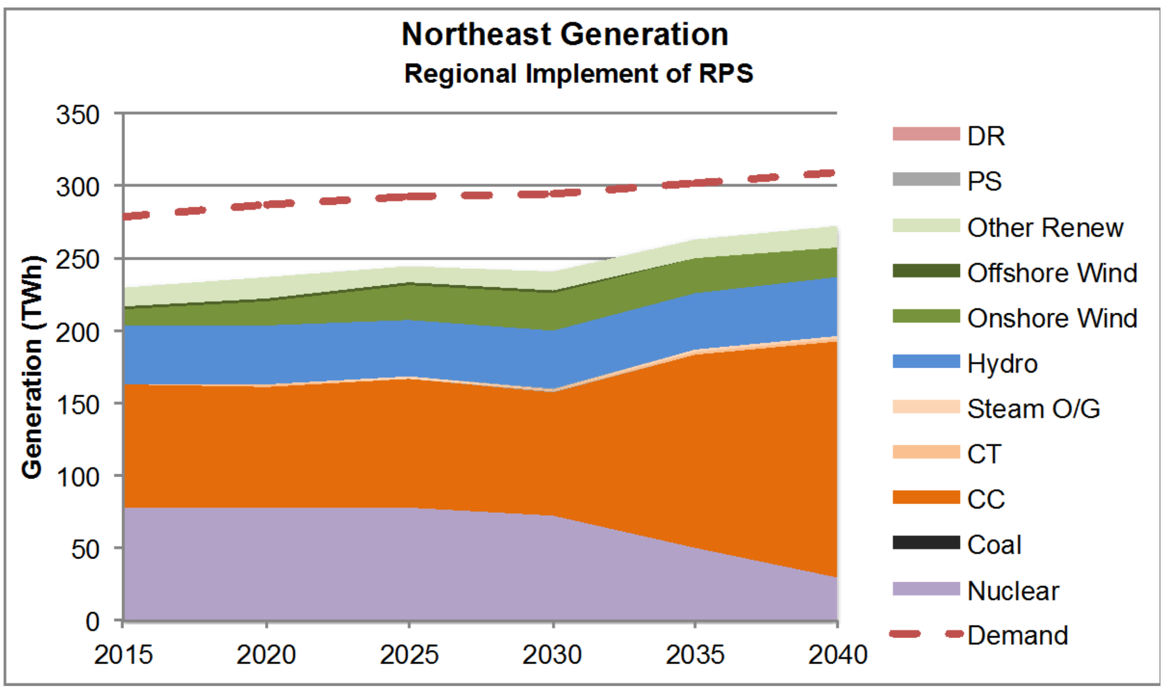

Fig. A-18. Northeast generation over study period in the RPS/R future

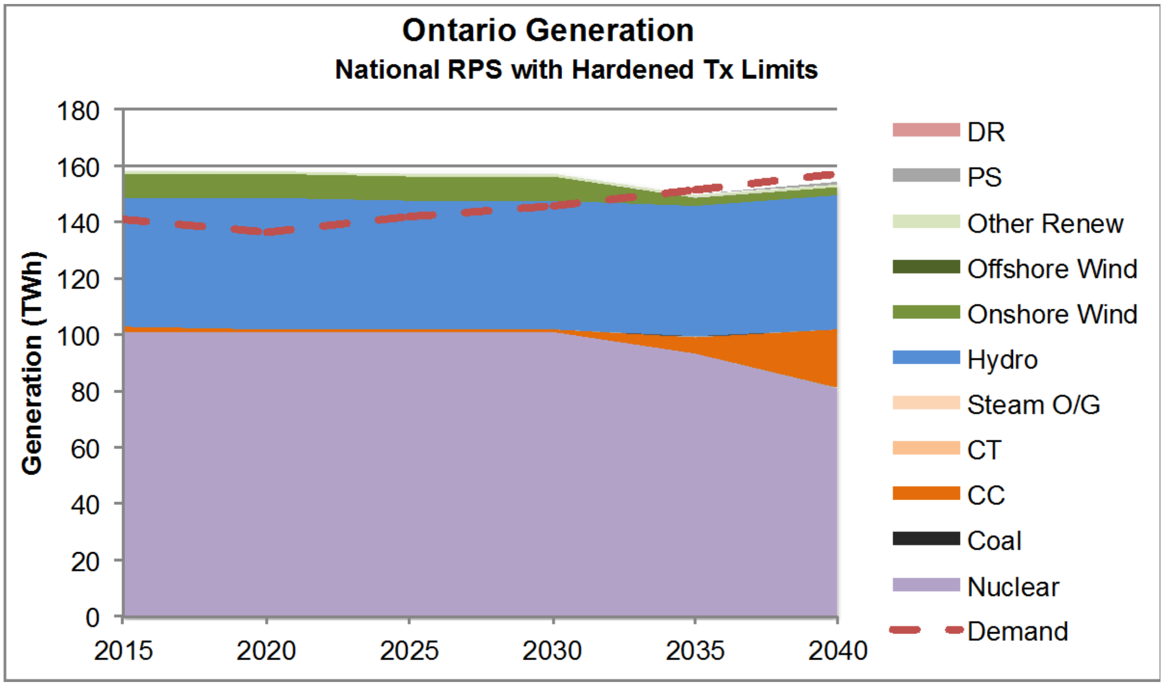

Fig. A-19. Ontario generation over study period in the RPS/N future

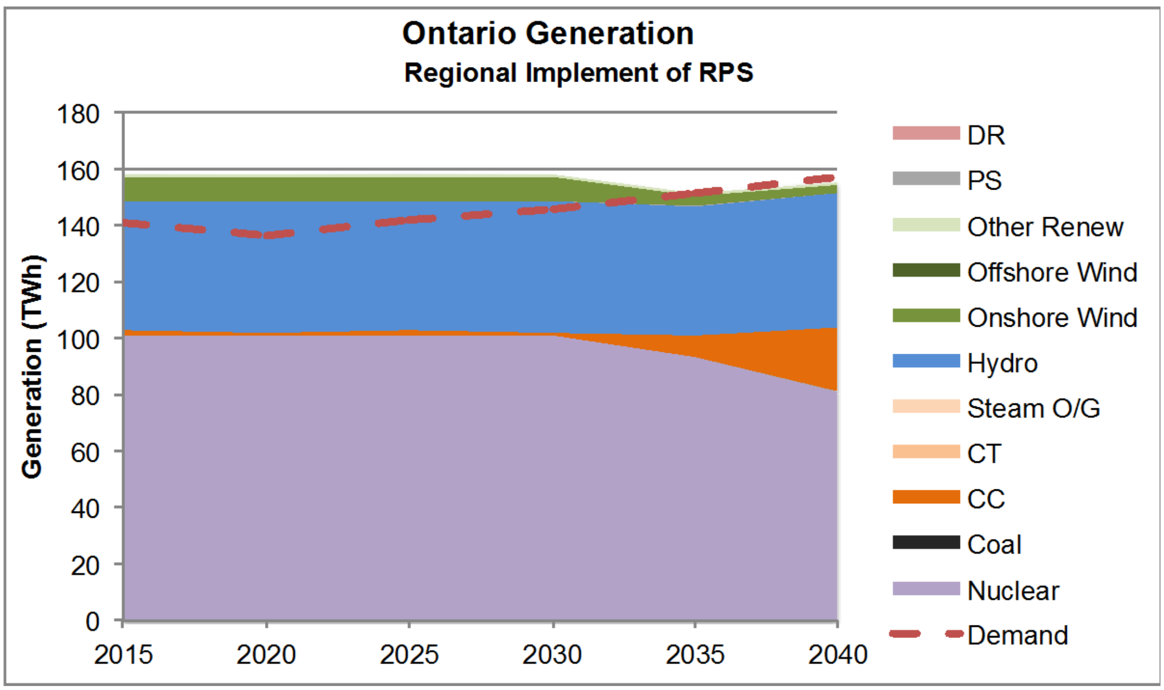

Fig. A-20. Ontario generation over study period in the RPS/R future

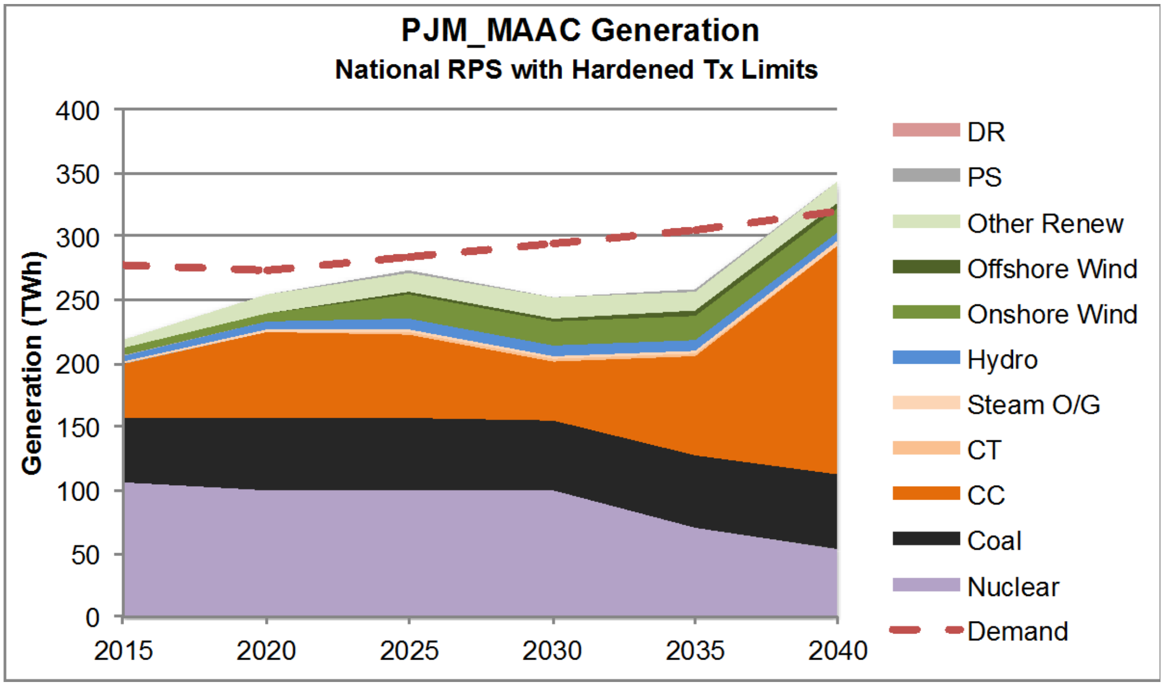

Fig. A-21. PJM MAAC generation over study period in the RPS/N future

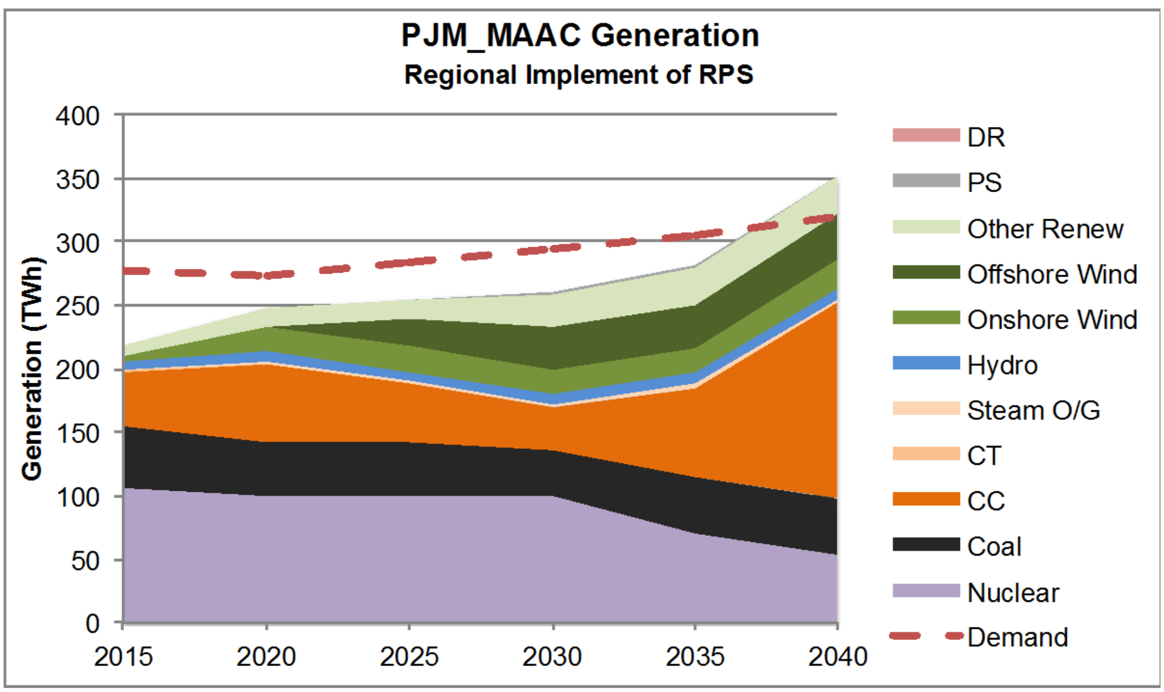

Fig. A-22. PJM MAAC generation over study period in the RPS/R future

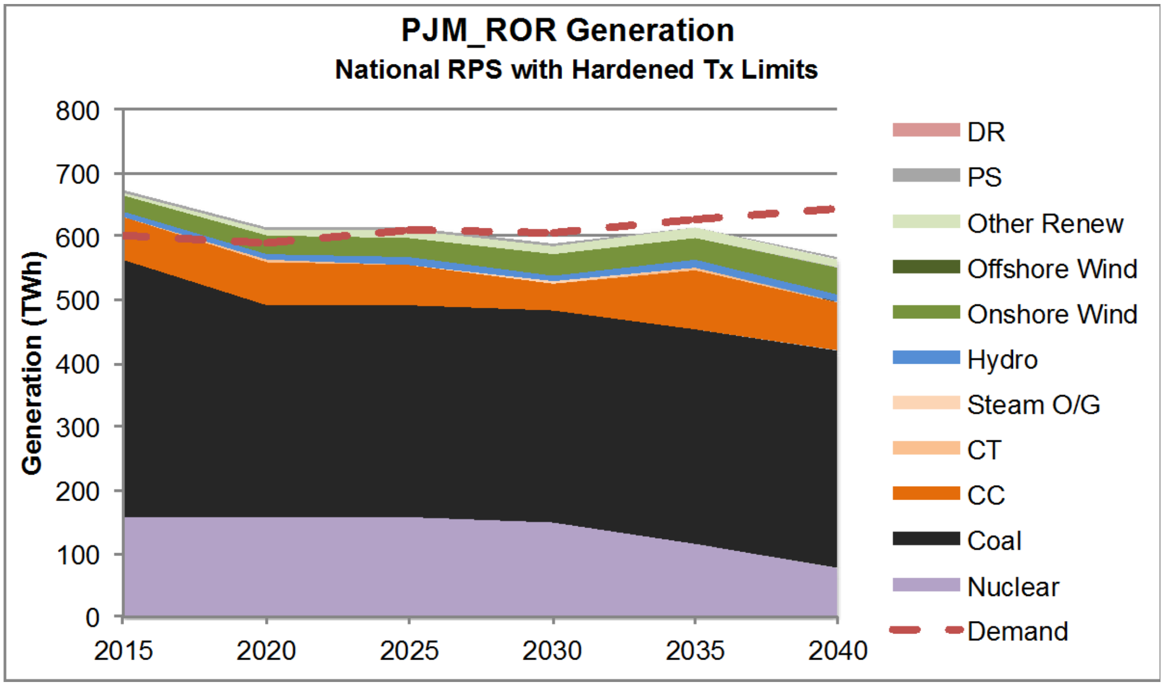

Fig. A-23. PJM ROR generation over study period in the RPS/N future

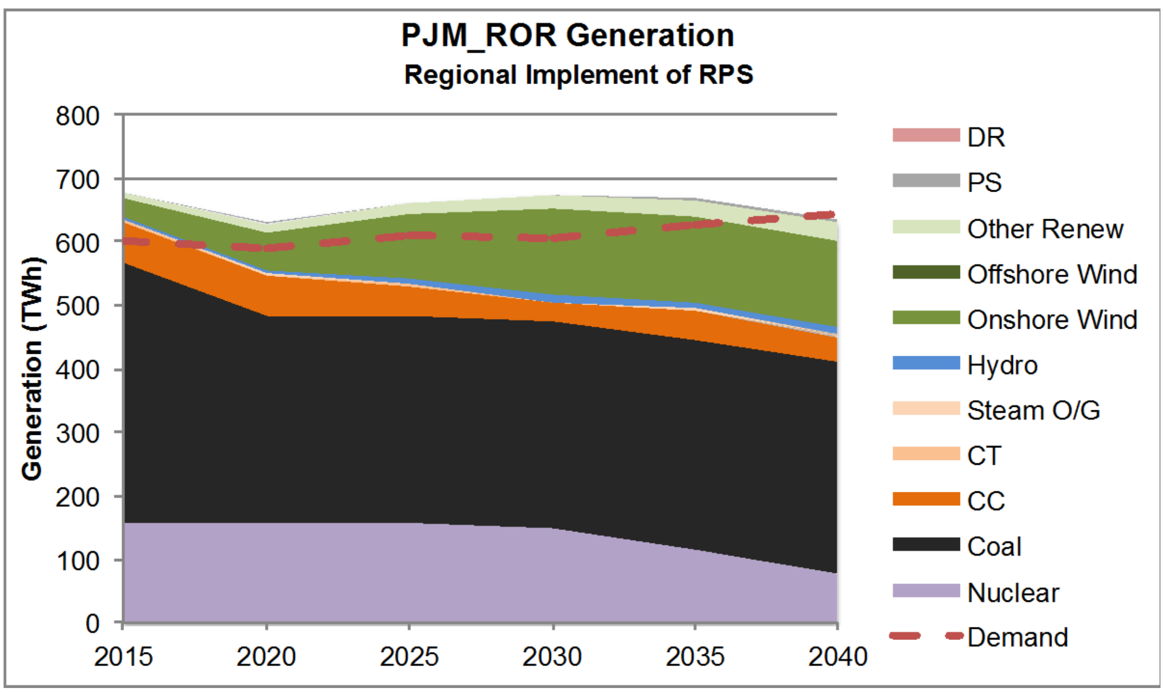

Fig. A-24. PJM ROR generation over study period in the RPS/R future

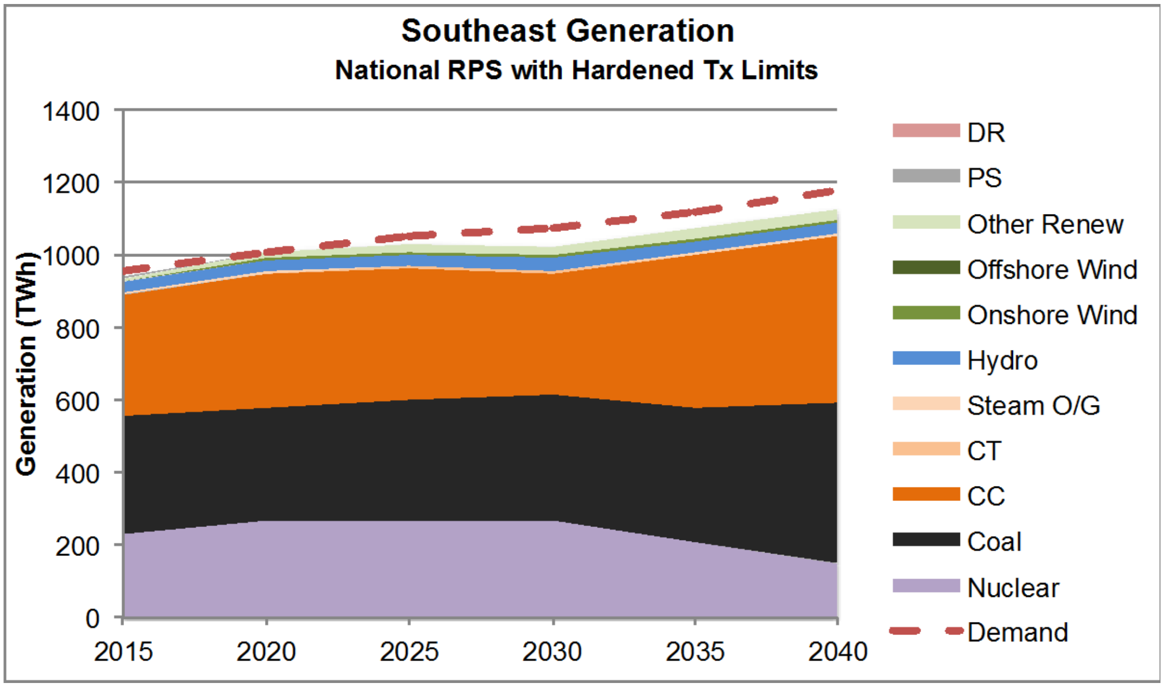

Fig. A-25. Southeast generation over study period in the RPS/N future

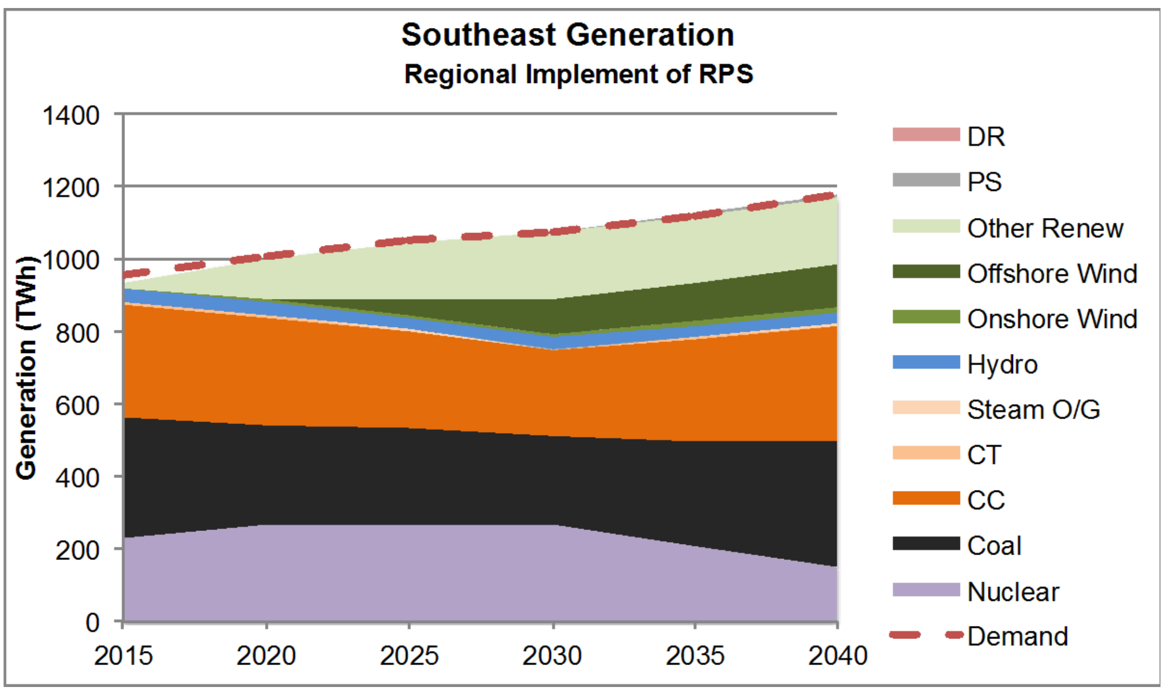

Fig. A-26. Southeast generation over study period in the RPS/R future

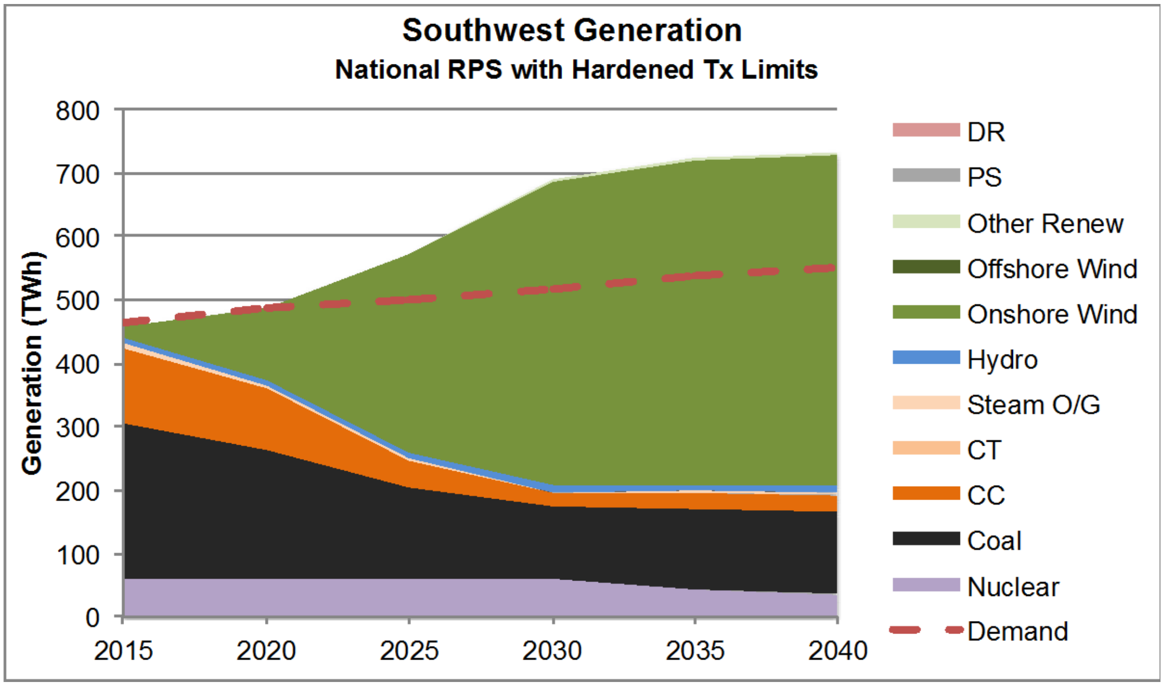

Fig. A-27. Southwest generation over study period in the RPS/N future

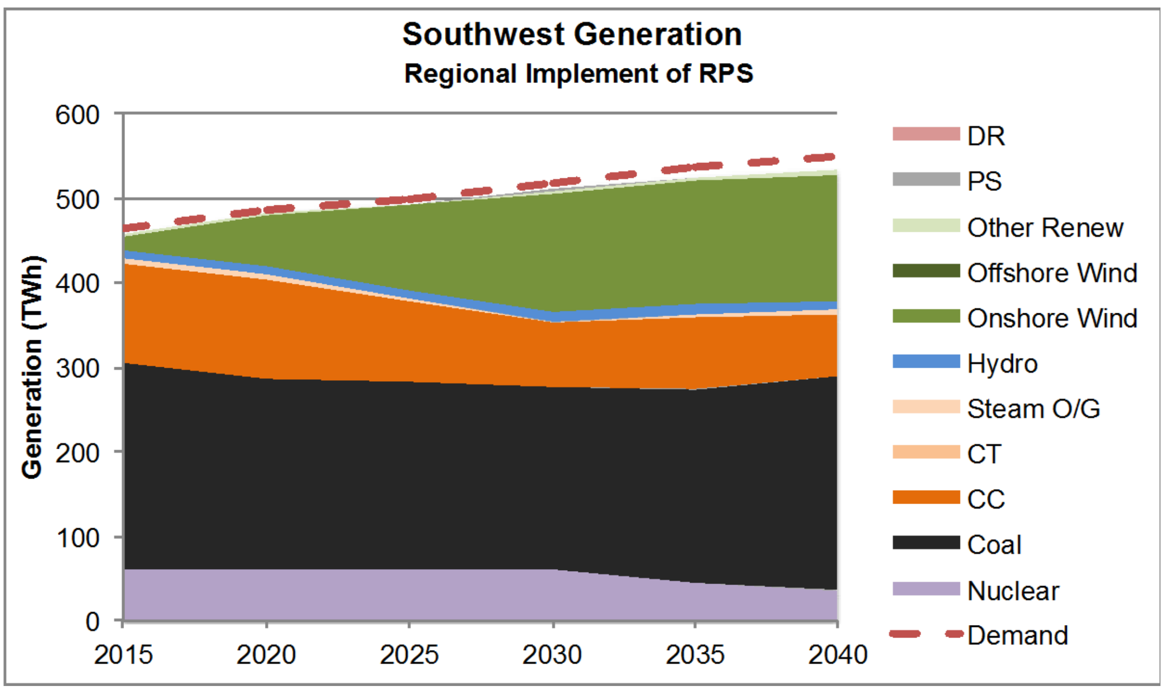

Fig. A-28. Southwest generation over study period in the RPS/R future