Eastern Interconnection Planning Collaborative

Phase 2 Report:

Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study

DOE Award Project DE-OE0000343

July 2, 2015

Volume 2
Sections 1-7

FINAL

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List of Acronyms

AECI	Associated Electric Cooperative, Inc.
BAU	Business as Usual
CEII	Critical Energy Infrastructure Information
CF	Capacity factor
CO_2	Carbon dioxide
CP	Combined Policies
CRA	Charles River Associates
DG	Distributed Generation
DOE	Department of Energy
DR	Demand response
EE	Energy efficiency
EHV	Extra high voltage
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EWITS	Eastern Wind Integration and Transmission Study
FCITC	First Contingency Incremental Transfer Capability
FF	Fabric Filter
FLHR	Full load heat rate
FOA	Funding Opportunity Announcement
FRCC	Florida Reliability Coordinating Council
HVAC	High voltage alternating current
HVDC	High voltage direct current
IESO	Independent Electricity System Operator of Ontario
ISO-NE	Independent System Operator--New England
Keystone	Keystone Center
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator
MRN	Multi-Region National
MW	Megawatt
MWG	Modeling Working Group
MWh	Megawatt hour
NADR	National Assessment of Demand Response
NARUC	National Association of Regulatory Utility Commissions
NEEM	North American Electricity and Environment Model
NERC	North American Electric Reliability Corporation
NGO	Non-government organization
NO_x	Nitrogen oxides
NRPS/IR	National Renewable Portfolio Standard/Implemented Regionally
NYISO	New York Independent System Operator
O&M	Operation and maintenance
PA	Planning Authority
PJM	PJM Interconnection
PPA	Participating Planning Authority
PSS/E	Power System Simulator for Engineering

PSS/MUST	Power System Simulator for Managing and Utilizing System Transmission
PV	Photovoltaic
RGGI	Regional Greenhouse Gas Initiative
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SOCO	Southern Company
SOPO	Statement of Project Objectives
SPP	Southwest Power Pool
SSC	Stakeholder Steering Committee
SSI	Stakeholder Specified Infrastructure
SSMLFWG	Steady State Modeling Load Flow Working Group
TDF	Transmission Distribution Factor
TOTF	Transmission Options Task Force
TPL	Transmission planning
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas
VER	Variable energy resource

Acknowledgement

This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory, under Award Number DE-OE0000343.

Disclaimers

The information and studies discussed in this report are intended to provide general information to policy-makers and stakeholders but are not a specific plan of action and are not intended to be used in any state electric facility approval or siting processes. The work of the Eastern Interconnection States Planning Council or the Stakeholder Steering Committee does not bind any state agency or Regulator in any state proceeding.

1 Introduction and Background

The Eastern Interconnection Planning Collaborative (EIPC) received funding from the U.S. Department of Energy (DOE) in 2010 to initiate a broad-based, transparent collaborative process to involve interested stakeholders in the development of policy futures for transmission analysis. This report describes the work performed in Phase 2 of the project and forms a companion document to the report published in December 2011 that encompasses Phase 1 of this analysis.

Regional, multi-regional, and interconnection-wide studies and planning provide the potential for improvements in reliability and significant economic benefits for ratepayers when compared to the alternative approach of planning only on a local basis. They also provide the potential for the following:

- Increased opportunities for states and federal agencies to work cooperatively on planning, siting, and constructing new (or upgraded) infrastructure to better ensure that necessary infrastructure is constructed in a timely manner.
- Expanded opportunities to work with Planning Coordinators and other stakeholders on routine planning matters apart from contested proceedings.

Throughout the Eastern Interconnection, Planning Coordinators (formerly called Planning Authorities) manage their individual local and regional planning processes. The EIPC was initiated by a coalition of regional Planning Coordinators and represents a first-of-its-kind effort to involve Planning Coordinators throughout the Eastern Interconnection to model the impact of various policy options determined to be of interest by state, provincial and federal policy makers, and other stakeholders on the entire Eastern Interconnection. The work of the EIPC builds upon, rather than replaces, the current local and regional transmission planning processes implemented by the Planning Coordinators and associated regional stakeholder groups within the Eastern Interconnection.

1.1 DOE Funding Opportunity Announcement – Overview and Purpose

In June 2009, DOE issued a Funding Opportunity Announcement (FOA), DE-FOA-0000068, which provided funding to prepare analysis of transmission requirements under a broad range of alternative futures. The DOE FOA covered two specific topics. Topic A was to fund Interconnection-level analysis and planning work while Topic B was to fund cooperation among States on electric resource planning and priorities. DOE anticipated issuing three awards under each Topic, corresponding to the three geographic areas served by the three major interconnections (Eastern, Western, and Texas).

In August 2009, the Planning Coordinators in the Eastern Interconnection reached agreement through a formal contract on the formation of the EIPC. The group developed a proposal submitted by PJM Interconnection, LLC (PJM) in August 2009, on behalf of the EIPC to perform the Topic A work under the DOE FOA. All 26 EIPC members supported the work prescribed for Topic A. Eight of the 26 members are designated as Principal Investigators, who bear additional responsibilities with respect to project execution, management and reporting, along with American Transmission Co., which is a sub-recipient. PJM serves as the lead Principal Investigator for the project.

The Eastern Interconnection Topic A cooperative agreement awarded to PJM, DE-OE0000343, is titled the Eastern Interconnection Planning Collaborative (EIPC). EIPC chose to retain Whiteley BPS Planning Ventures, LLC, to support project management; The Keystone Center (Keystone) to support stakeholder process facilitation; and Charles River Associates (CRA) to support macroeconomic analysis and production cost studies.

In response to DOE's FOA, the 39 States in the Eastern Interconnection, along with the District of Columbia and the City of New Orleans, came together to form the Eastern Interconnection States Planning Council (EISPC). The National Association of Regulatory Utility Commissioners (NARUC) applied to DOE, on behalf of EISPC, for funding under the FOA's Topic B for the Eastern Interconnection.

The Eastern Interconnection Topic B cooperative agreement was awarded to NARUC. NARUC's project, DE-OE0000316, is titled the Eastern Interconnection States Planning Council (EISPC). Similar application and award negotiations occurred for both Eastern Interconnection awards. The Eastern Interconnection Topic A and B recipients made a special effort to coordinate their work.

Once created, EISPC and the Stakeholder Steering Committee (SSC) each created their own internal organizational structures, as well as By-Laws governing meetings, communications, governance and collaborative decision-making processes.

1.2 Statement of Project Objectives

PJM's and NARUC's awards each incorporate a Statement of Project Objectives (SOPO). Each applicant to the FOA submitted a draft SOPO that, following selection, was revised during award negotiations. The SOPO provides project objectives, tasking, and required deliverables. The negotiated SOPOs are included in Appendices 1 and 2 of EIPC's Phase 1 interim report.

Two objectives were stated in the EIPC SOPO:

1. Establish processes for aggregating the modeling and regional transmission expansion plans of the entire Eastern Interconnection and perform interregional analyses to identify potential conflicts and opportunities between regions. This interconnection-wide analysis would serve as a reference case for modeling various alternative grid expansions based on the scenarios developed by stakeholders.

2. Perform scenario analysis as guided by broad stakeholder input and the consensus recommendations of a stakeholder committee formed under the proposal. The analysis would serve to aid federal, state, and provincial regulators, as well as other policy makers and stakeholders in assessing interregional options and policy decisions.

1.3 Scope and Schedule of Work

1.3.1 EIPC

The scope of work proposed by the EIPC in the SOPO was divided into 13 tasks within two phases. Phase 1 included the following tasks:

- Task 0 – Project Management and Planning
- Task 1 – Initiate Project
- Task 2 – Integrate Regional Plans
- Task 3 – Production Cost Analysis of Regional Plans
- Task 4 – Macroeconomic Futures Definition
- Task 5 – Macroeconomic Analysis
- Task 6 – Expansion Scenario Concurrence

Phase 2 of the project proposed developing and analyzing transmission expansion options for the three scenarios selected by the SSC in Task 6 at the end of Phase 1. For each of the three scenarios selected, the work in Phase 2 includes the following tasks:

- Task 7 – Interregional Transmission Options Development
  - Modify powerflow models built in Task 2 to create interregional transmission expansion models for each scenario.
  - Develop and test transmission options that will provide reliable delivery of the power transfers specified by the North American Electricity and Environment Model (NEEM) and create a reliable transmission system within and between each NEEM region in accordance with selected (but not all) North American Electric Reliability Corporation (NERC) reliability criteria.
- Task 8 – Reliability Review
  - Perform reliability analysis consistent with NERC reliability criteria regarding bus outages, common tower outages and combination generation/transmission element outages on each scenario.
  - Develop flowgates required in Task 9 for performing production cost analysis.
- Task 9 – Production Cost Analysis of Interregional Expansion Options
  - Develop the necessary inputs for the production cost model (GE-MAPS) consistent with scenario assumptions used in the NEEM model.
  - Perform economic analysis using production cost modeling for each scenario.
- Task 10 – Generation and Transmission Cost Estimates
  - Perform high-level cost estimates for transmission expansion options for each scenario.
  - Develop costs associated with resource additions and retirements for each scenario.
- Task 11 – Review of Results
  - Produce a draft report on the Phase 2 effort.
  - Present the results of the analysis, respond to questions, and solicit input from stakeholders.

  - Provide SSC consensus-based comments on the draft report.
- Task 12 – Phase 2 Report
  - Review the input received from the SSC and address it in the final report.

There have been two core changes to the SOPO initiated by the SSC and supported by DOE. The first was to replace the Planning Authorities' Roll-up Model with a new Stakeholder Specified Infrastructure (SSI) model to serve as the starting point for all of the remaining DOE project work. The second change to the SOPO related to eliminating the production costing work that was planned under Task 3 in Phase 1 of the project.

The initial work was completed in accordance with the SOPO and highlighted issues that required further investigation. On February 13, 2013 PJM received technical guidance[1] from DOE in response to the Project draft Phase II report dated December 22, 2012. This technical guidance requested that analyses be completed on the gas-electric system interface because it deserves a more in-depth analysis than originally envisioned. The technical guidance requested PJM to revisit three tasks:

- Task 1, Initiate Project, to adjust the process to obtain stakeholder input on the project and the structure of the SSC, because in its present form the membership emphasizes electricity stakeholders with minimal, if any, natural gas focus;
- Task 11, Review of Results, to evaluate the interaction between natural gas and electricity systems; and
- Task 12, Phase II Report, to revise the draft Phase II report to include the results of the gas-electric system interface analysis.

The DOE FOA specified that the Topic A project work was to be completed by June 30, 2013. However, DOE extended the required completion date for EIPC studies to July 18, 2015 to accommodate the additional time needed to perform the Gas-Electric System Interface Study.

1.3.2 EISPC

The Eastern Interconnection Topic B project leader, EISPC, also had a SOPO including objectives, scope and tasks. Per that SOPO, the objective of EISPC is to provide for cooperation among states on electric resource planning and priorities. NARUC will facilitate dialogue and collaboration among the states in the Eastern Interconnection and thus enable them to develop more consistent and coordinated input and guidance for the regional and interconnection-level analyses and planning that will be done under the Topic A award for the Eastern Interconnection.

EISPC's scope includes the following:

- Identify Eastern Energy Zones of particular interest for low- or no-carbon electricity generation. The Recipient will allow for regional diversity and determine how the

[1] "Request for Concurrence on Technical Guidance to be Provided to PJM Interconnection L.L.C. in Response to Its Draft Phase 2 Report on the Eastern Interconnection Planning Collaborative Award, Cooperative Agreement No. DE-OE0000343 dated January 3, 2013".

identification of Eastern Energy Zones could best serve the collective interests of the affected states.

- Conduct studies on key issues related to reliable integration of variable renewables into the Eastern Interconnection and any other studies needed to better enable member state participation in regional and interconnection-wide analyses and planning.
- Develop other inputs as needed to go into the interconnection-level analyses prepared under the Eastern Interconnection Topic A work.
- Provide insight into the economic and environmental implications of the alternative electricity supply futures and their associated transmission requirements developed for the Eastern Interconnection under Topic A.
- Demonstrate (and develop if necessary), a process for reaching decisions and consensus appropriate for an interconnection-wide entity representing all of the states and provinces in the Eastern Interconnection so as to participate in the development and updating of the long-term interconnection-level plan under Topic A.

EISPC's eight tasks are as follows:

- Task 1 – Organizational development and project management.
- Task 2 – Reach consensus decisions on the Recipient's position on modeling inputs and assumptions via expansion of transmission planning knowledge base.
- Task 3 – Assemble data for analysis of Eastern Interconnection Topic A Roll-up Integration Case and reach consensus on feedback and input into the Eastern Interconnection Topic A.
- Task 4 – Conduct studies to facilitate further refinement of the modeling inputs and future scenarios.
- Task 5 – Prepare White Papers.
- Task 6 – Reach consensus on the Recipient's positions on the future scenarios for macroeconomic analysis to be conducted by Eastern Interconnection Topic A Recipient.
- Task 7 – Reach consensus on the Recipient's positions on the transmission build-out scenarios to be conducted by the Eastern Interconnection Topic A Recipient.
- Task 8 – Participate in Eastern Interconnection Topic A activities.

1.4 Three Scenarios Analyzed in Phase 2

Phase 2 Tasks 7 and 8 of the project were more engineering-focused with the transmission planning engineers of the Planning Authorities building models for the three scenarios and testing those models against specific NERC reliability criteria. Because some of the data and information shared in the process was deemed Critical Energy Infrastructure Information (CEII), precautions were necessary to ensure that those stakeholders receiving that information were authorized to receive CEII and a process was set up for stakeholders to receive CEII clearance if they needed it. In addition, the EIPC requested that members of the Transmission Options Task

Force, whose members were designated by the SSC, be technically qualified to participate in the transmission planning discussions. The Planning Authorities used the models to identify overloads on the system (line trying to carry more power than it is designed to carry) or Voltage issues (Voltage either too high or too low). Then, they identified possible transmission fixes for the contingencies and tested those transmission options in the models to ensure the transmission system would operate reliably.

The Planning Authorities also developed the flow gates needed for Task 9, Production Cost Analysis, and the high-level transmission cost estimates needed for Task 10.

Task 9 of Phase 2 involved developing production cost estimates of each of the three base scenarios and an additional six sensitivities. The work was performed by Charles River Associates using the GE-MAPS model. In a change from the approach in Phase 1, the base scenario results were made available to stakeholders before the decision on sensitivity analyses was required.

The Modeling Work Group (MWG) from Phase 1 was reconvened to develop the inputs needed for the production cost modeling and to recommend sensitivities to the SSC. The guiding premise of the group was that inputs would remain the same as the inputs that were developed for the NEEM modeling done in Phase 1. Where more specificity was needed, the inputs would be consistent with the NEEM assumptions and outputs.

The production cost base model runs for each Scenario were performed and presented to the Stakeholder Steering Committee. In addition, six sensitivities were available to provide more insight into the model results. There was stakeholder concern about the level of wind curtailment in Scenario 1: Combined Policies and ultimately four of the six sensitivity runs were used to understand this issue better. The other two sensitivities were applied to Scenario 3: Business as Usual and involved changes in load and natural gas prices. In addition, the high use of Demand Response and high Locational Marginal Prices in the southeast were explored with these sensitivities.

1.4.1 Scenario 1: Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response

The first scenario selected for Phase 2 analysis was a national carbon constraint and demand reduction scenario, driven by a nationally implemented CO_2 price, as well as significant penetration of energy efficiency (EE) and demand response (DR). Costs of EE and DR are assumed to be partially offset by the CO_2 revenues.

The scenario includes a CO_2 price that escalates annually to achieve a 42% reduction in CO_2 emissions from 2005 levels throughout the economy by 2030, but then becomes flat after 2030. The scenario also includes very aggressive EE/DR assumptions; however, much of the reduction in demand is due to adjustments in demand from the higher energy prices driven by the CO_2 price signals. The combined effect of the aggressive EE/DR and the carbon price results in a 19% reduction from 2011 Eastern Interconnection-wide demand by 2030 and greater than 30% of energy delivered with renewable resources. The peak demand in the Eastern Interconnection used in this scenario was 565,012 MW, resulting from the assumption in Phase 1 that aggressive energy efficiency and other forms of demand response would reduce the actual demand from 2011 levels by 1% per year. In addition, for Scenario 1, because of the significant wind build-out an off-peak case was needed as part of the reliability analysis. The demand used in modeling the transmission system in the off-peak case was 351,750 MW.

This first scenario results in the most expansive transmission build-out of the three scenarios, and, based on the clustering analysis conducted as part of Phase 1, is anticipated to be robust enough to accommodate the transmission needs under a number of the futures analyzed in Phase 1:

- Future 5: National Renewable Portfolio Standard – National Implementation,
- Future 2: National Carbon Constraint – National Implementation, and
- Future 4: Aggressive Energy Efficiency, Demand Resources and Distributed Generation.

The required additional transfers over the limits in the SSI model that were identified in the NEEM analysis for Scenario 1 were approximately 37,000 MW.

1.4.2 Scenario 2: Regionally Implemented National Renewable Portfolio Standard

The main defining characteristic of this scenario is the deployment of significant amounts of local renewable energy. Scenario 2: Regionally Implemented National Renewable Portfolio Standard requires that 30% of each region's load in 2030 be met with renewable resources within that region to the extent possible. The scenario assumes that a load serving entity has the option to meet the requirement by purchasing renewable energy credits from other entities. The definition of qualified renewable facilities includes wind, solar, geothermal, biomass, landfill gas, fuel cells using renewable fuels, marine hydrokinetic, and hydropower. This future results in moderate transmission expansion and investment with additional transfers of 3,100 MW. The peak demand for the Eastern Interconnection in this scenario was 673,108 MW, while the off-peak demand utilized was 421,692 MW.

The greater diversity in supply mix, including with coal, gas, wind, nuclear, hydropower, offshore wind and other renewable technologies generation, was an important reason why the SSC selected this scenario. Additionally, stakeholders supported the selection of Scenario 2 because, in combination with the other two scenarios chosen, it provides information about a wide range of policy drivers. Moreover, in light of current economic and political circumstances, the SSC agreed that the enactment of higher RPS requirements is more likely than additional state-by-state carbon regulations.

This scenario was modeled using seven super regions, designed to enable regions to meet the RPS goals using regional resources first. Super regions are made up of multiple NEEM regions and align in most cases with the regional Planning Coordinator boundaries. The objective of this scenario was to have each "Super Region" supply its own renewable resources. To implement this regional approach, transfer limits between super regions were not permitted to expand.

Figure 1-1 is a depiction of the NEEM regions that make up each super-region.

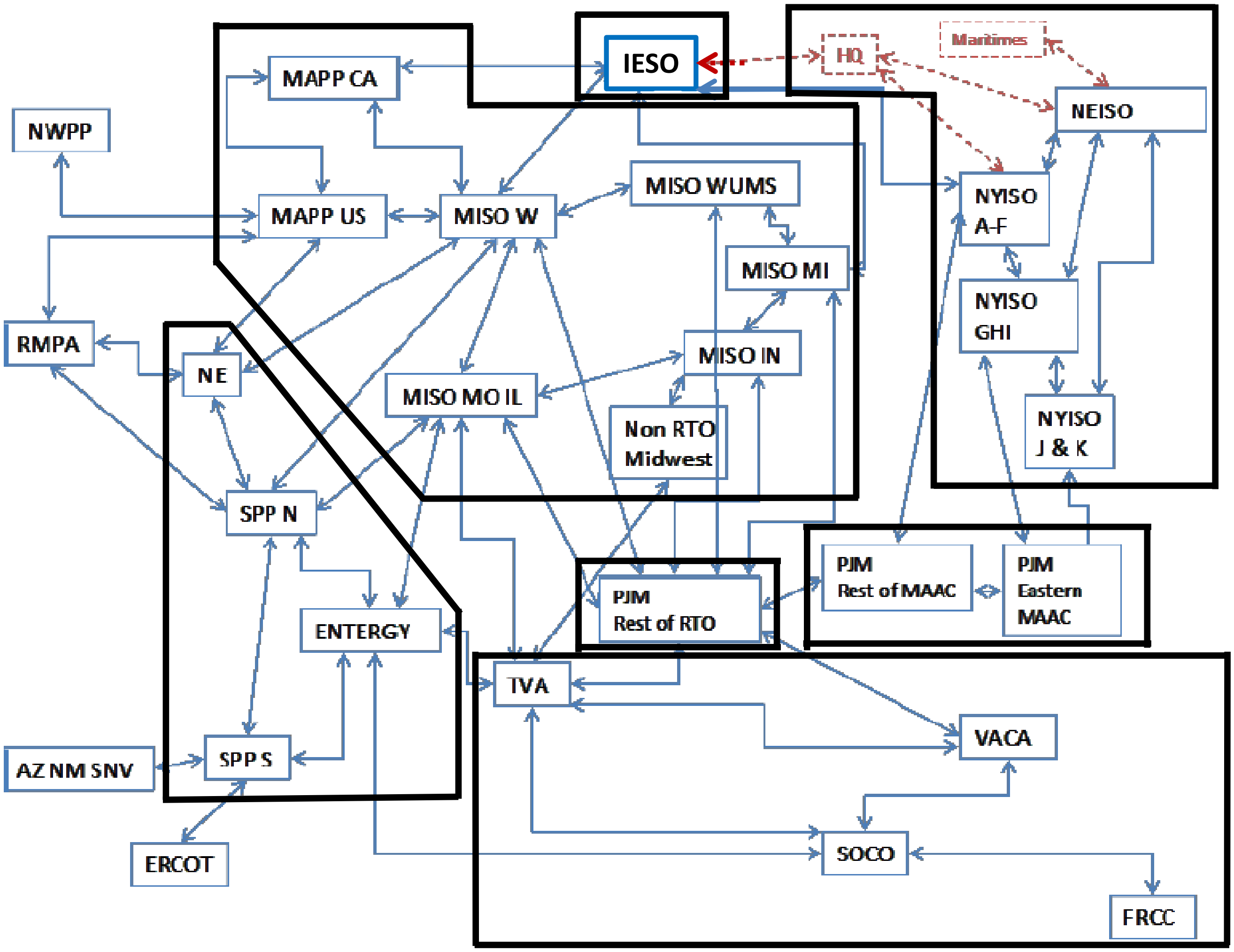


Figure 1-1. NEEM Regions (blue) and Super-Regions (black)

In addition, the Eastern Interconnection interfaces with Hydro Quebec, WECC and ERCOT are represented using export/import border assumptions, as is the Maritimes portion of the Eastern Interconnection.

1.4.3 Scenario 3: Business as Usual

The Business as Usual scenario is characterized by continuation of current federal, state, and/or regional energy or related environmental policies and programs without enactment of new policies. Proposed EPA regulations from summer 2011, including the Transport Rule, Utility MACT Rule, Utility NSPS Rule, Coal Combustion Residuals Rule, and Cooling Water Intake Structures Rule, are assumed to be implemented. Policies and/or regulations with an expiration/sunset date were renewed on a case-by case basis. The assumptions regarding EPA regulations led to the retirement of roughly 82 GW of coal capacity (by 2020 – see Phase I, F1S17 (BAU) Stakeholder Report Build Summary); based on the results of the Phase I economic resource expansion process, this generation (and other retiring oil/gas steam generation) was replaced with natural gas combined cycle and combustion turbines, nuclear generation, and wind generation to collectively meet capacity reserve requirements and the state RPS requirements. Fuel prices remain stable and there are no major technological advances. The peak demand for the Eastern Interconnection in this scenario is 690,942 MW.

In this scenario, the SSC decided not to expand NEEM transfer limits beyond the projects that were specified as part of the SSI. Below is a map of the transmission additions that were accepted as part of the SSI.

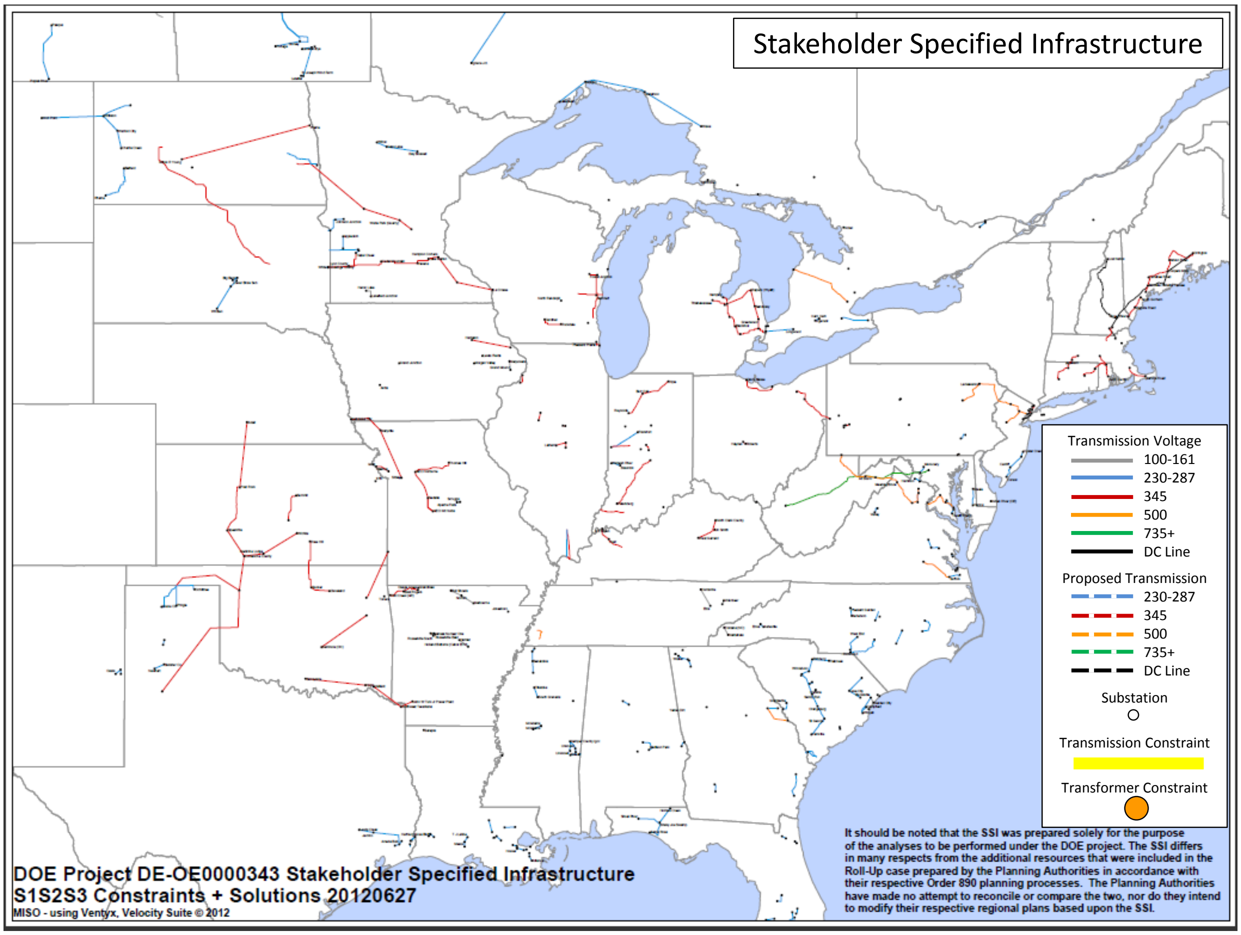
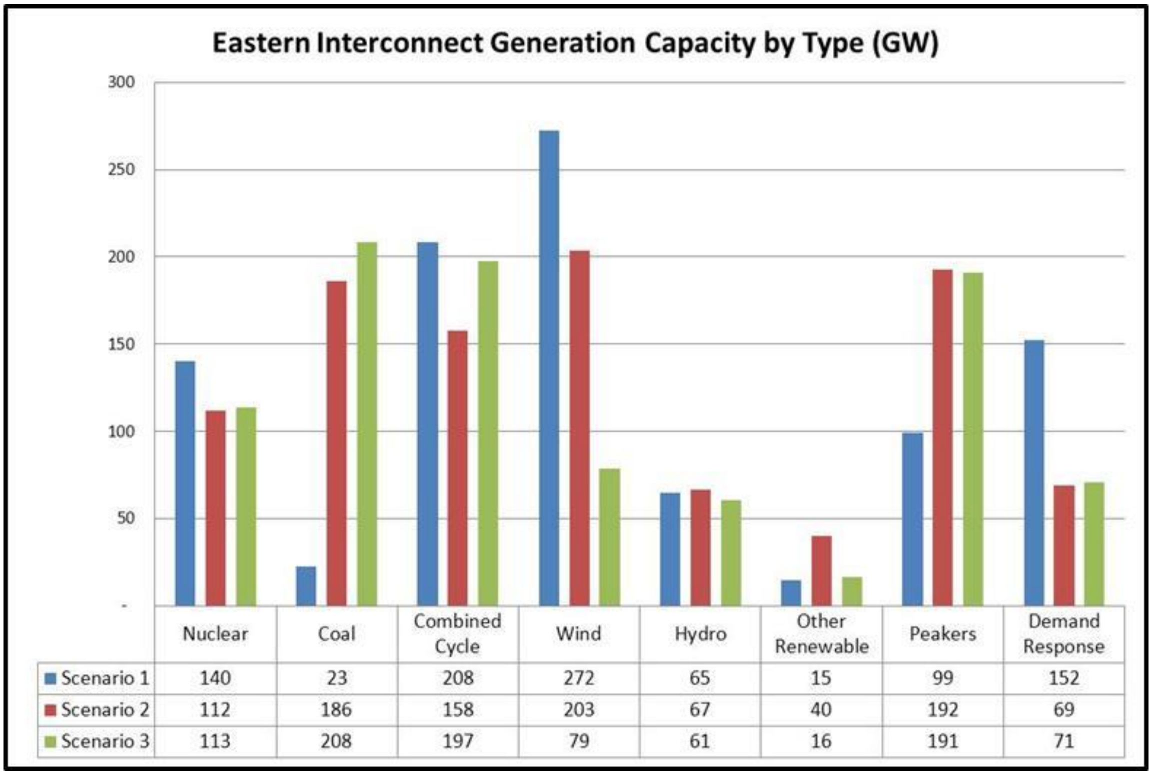


Figure 1-2. SSI Transmission Additions

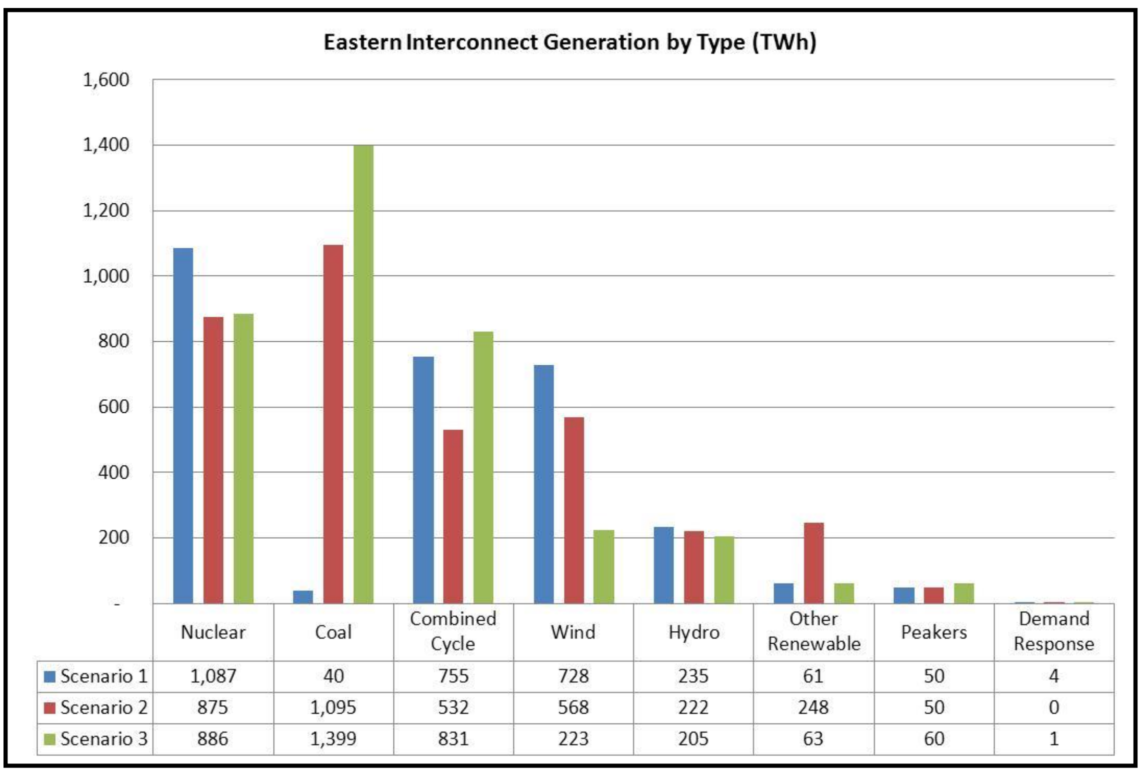
The Business as Usual scenario had a significant number of generation deactivations and new builds. The Planning Authorities expected this to cause the need for some transmission development within the NEEM regions to ensure continued system reliability. Given the load levels in this scenario, the Transmission Options Task Force decided that many of the deactivated generation units would be replaced with new, different types of generation at the same location, as this was more efficient from a transmission development perspective.

Figures 1-3 and 1-4 depict the resultant generation capacity and energy based on stakeholder specified assumptions utilized in the all three scenarios.



	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	140	23	208	272	65	15	99	152
Scenario 2	112	186	158	203	67	40	192	69
Scenario 3	113	208	197	79	61	16	191	71

Figure 1-3. EI Generation Capacity



	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	1,087	40	755	728	235	61	50	4
Scenario 2	875	1,095	532	568	222	248	50	0
Scenario 3	886	1,399	831	223	205	63	60	1

Figure 1-4. EI Energy

Phase 1 of the project focused on developing the stakeholder processes, developing and specifying inputs for eight different futures and an additional seventy-two sensitivities, and identifying the generation resources (location, type and amount) and additional transfers needed to support the futures. This effort involved stakeholders in direct and detailed conversations developing the futures and sensitivities and the many inputs needed for analysis. Stakeholders were also directly involved in reviewing results and choosing the final three scenarios.

1.5 Gas-Electric System Interface Study

Six Eastern Interconnection PAs participated in the Gas-Electric System Interface Study. These Participating Planning Authorities (PPAs) are: ISO-NE; NYISO; PJM; IESO; MISO, including the Entergy system; and TVA. The combined geographic areas of these PPAs will be the Study Region for the additional consideration of the natural gas/electric infrastructure interface.

The Gas-Electric System Interface Study was comprised of four Target areas:

- Target 1: Baseline assessment and description of the natural gas-electric system interface
- Target 2: Evaluation of the capability of the natural gas system to supply the fuel requirements of the electric power sector
- Target 3: Analysis of selected contingencies of the gas and electric systems to determine the ability of the natural gas pipeline system to continue to provide gas service to electric generation.
- Target 4: Review the availability and cost of providing dual-fuel capability at electric generating stations compared with cost the cost of obtaining firm gas transportation service.

The results of the Gas-Electric System Interface Study provide a comprehensive analysis across the region of the adequacy of the natural gas pipeline delivery system to meet the needs of gas-fired electric generation system under various conditions over a 10-year horizon. In addition, the study identified constraints on the natural gas pipeline system that may affect the delivery of gas to specific generators following a variety of postulated gas and electric system contingencies. The study also describes a number of mitigation measures that may be considered by gas and electric system operators to alleviate the impacts on the electric system under such conditions. The results of this study provide a wealth of information for consideration by the Participating Planning Authorities and regional stakeholders to inform their respective operational and planning analyses.

1.6 Unique Study Characteristics

This is a first of its kind effort for the Eastern Interconnection. As such, it has a number of unique characteristics that are not found in local or regional planning processes. A number of these characteristics are listed below.

- Complexity and differences among the regions had to be accommodated in this joint effort.
- The SSC provided modifications to the roll-up as a starting point for resource analyses.

- The SSC negotiated certain input assumptions and those assumptions needed to be placed into the context and purpose of the analysis.
- The Stakeholder consensus process worked well and required decisions were made, although additional time and effort was required to reach consensus.
- The process has led to a better understanding of regional similarities and differences and to the degree of complexity involved in an analysis of such a broad and diverse region.
- The process has provided all participants with a great deal of information that should be useful if similar studies are done in the future.
- Because of the complexity of factors involved in this type of analysis, there was never any intent to optimize or "co-optimize" every input to the model. There was also no intent to co-optimize the mix of transmission and generation in a particular scenario. Due to time and resource constraints, such co-optimization was not possible.
- The transmission planning analysis completed is an "indicative" result; it provides a relative indication of the amount and type of transmission that would be needed under each scenario.
- The transmission planning analysis is a strategic snapshot in time, utilizing year 2030. Traditional transmission planning is much more incremental and sequential process and would typically be done for periods five and ten years into the future, rather than twenty years into the future.

2 Developing Transmission Options for Reliability – Tasks 7 and 8

The work of Tasks 7 and 8 was to identify transmission reinforcements to reliably support the new generation, generation deactivations and interregional exchanges of energy for each of the three scenarios identified in Task 6 of Phase 1. The Transmission Options Task Force (TOTF) was formed as the vehicle for the Planning Authorities (PAs), in collaboration with stakeholders, to develop transmission expansion options focused on the extra high voltage (EHV) transmission network (230 kV and above). This analysis considered the transmission facilities required to reliably integrate new resources within a region using a similar high voltage focus, but did not attempt to resolve potential local transmission issues below 230 kV. Tasks 7 and 8 did involve ensuring each of the NEEM regions had a reliable EHV transmission system.[2] The EIPC leveraged the expertise of its membership in considering high-voltage direct current and advanced technologies in developing expansion options. This task was not intended to identify specific routing, siting, environmental, or other related issues associated with any potential enhancements to the power grid.

Transmission power flow analysis involves developing a model with all transmission, generation and loads for the single hour of the year where the system is the most stressed. Traditionally, this has been the peak hour of the year when the loads on the system are highest. With the advent of more renewable resources, especially wind, transmission planners are looking at additional hours. The complexity of reliability analysis, *e.g.*, running every single contingency individually in that peak hour model to ensure the system remains reliable, makes it impractical to perform power flow analysis on more than a few hours of the year. For this analysis, the TOTF chose one additional hour to model for Scenarios 1: Combined Policies (CP) and 2: National Renewable Portfolio Standard/ Implemented Regionally (NRPS/IR) because of their high wind output in remote locations. This was necessary because the majority of wind energy is available off-peak and the combination of the high wind energy, baseload plant minimums and light load levels can put stresses on the system that are different than the system stress created by peak hour conditions.

The objective of Tasks 7 and 8 was to develop conceptual transmission options for each of the three identified scenarios. These futures represent various policy directions and their resulting impacts, as represented by the year 2030. The length of the planning horizon (20 years) and the inherent high uncertainty levels associated with various input assumptions leads to more focus on higher voltages and interregional analysis. The details of more granular level analysis would very likely become more evident as the inherent uncertainties resolve over time. It must be noted that an examination of the conditions in the year 2030 represents one "snapshot" in time. Typical transmission planning processes evaluate the power grid on an annual basis over a ten-year period; *i.e.*, every year in the next ten-year period, instead of leaping to a distant horizon year, such as 2030, which may result in grid improvements made on a smaller, more incremental basis. The following process is therefore consistent with this project's objective and scope and is described in more detail in several process documents located at http://www.eipconline.com/TOTF.html, under the Nov 4, 2011 Webinar Materials section and at

[2] In Phase 1, as part of the NEEM "pipes and bubbles" analysis, each NEEM region was assumed to have no constraints to the movement of power within that region.

http://www.eipconline.com/uploads/Phase_II_Build_Out_Schedule_and_Outline_FINAL_12-6-11.pdf.

2.1 Formation and Purpose of TOTF

The TOTF was created to provide a forum for stakeholder review and comment on the EIPC development of transmission build-out alternatives that were considered for the infrastructure support of the generation resources and inter-regional flows identified in each of the three scenarios. The TOTF was not intended to be a decision-making body but rather a collaboration of the EIPC PAs and SSC-appointed experts to facilitate information sharing and the exchange of ideas during Tasks 7 and 8 of the project.

The composition of the TOTF included up to six members appointed by the States, up to two members appointed by each of the other seven sectors of the SSC, and thirteen members from the EIPC. There were several elements to the criteria established for membership on the TOTF. Each sector was requested to select a TOTF member who was (1) experienced in transmission planning, (2) willing and able to obtain required Critical Energy Infrastructure Information (CEII) clearance and (3) capable of contributing to the process of transmission alternatives development and discussing the technical characteristics and relative technical merits of alternate solutions. Generally, it was expected that each member would possess both the expertise and commitment needed to produce and evaluate transmission alternatives and work products of the TOTF.

The Phase 2 timeline provided specific points within Tasks 7 and 8 for stakeholder comment. This process of "review and comment" defined much of the interaction between the EIPC and stakeholder representatives of the TOTF. The EIPC PAs performed the power flow modeling as the TOTF went about its work of identifying a transmission build-out for each of the three scenarios identified at the end of Phase 1. The results of the analyses, along with proposed solutions, were then presented to the stakeholders of the TOTF via meetings or webinars/conference calls. TOTF members provided comment on any EIPC proposed solutions and/or proposed alternative solutions to be considered.

2.2 Transmission Options Task Force Activities

Initial meetings of the TOTF in November 2011 and January 2012 focused on clarifying the tasks, scope and activities of the TOTF.

Early meetings also focused on the EIPC PAs' efforts to develop power flow models for each of the three identified scenarios consisting of the following:

- the transmission topology from the SSI model from Phase 1, with a few adjustments,
- generation data from the Phase 1 NEEM model outputs (including non-location specific generation additions and both location specific and non-location specific deactivations pursuant to each scenario),
- load used per block per NEEM region, system losses assumptions from the SSI model, and

- interchange data from the NEEM model.

Several "passes," or iterations, of transmission topology options were run for each scenario, and reviewed by TOTF members during, and between, TOTF meetings. TOTF members also provided input and transmission alternatives for consideration by the PAs as the various passes were completed for each scenario. The EIPC PAs continued to run these iterations for each of the three scenarios, taking stakeholder comments into consideration. For each scenario the PAs developed a transmission system that was free of 200 kV and above overloads and low/high voltages and met basic tests for reliability (described below), while remaining consistent with the assumptions inherent to each scenario for the hours modeled.

2.3 Power Flow Analysis Description

The following section describes the approach to power flow analysis, used by the EIPC PAs and discussed with the TOTF, to develop the models for the three scenarios. It contains a brief summary of transmission planning and is followed with more detailed information on the tools, required data, and testing processes used by the EIPC TOTF.

2.3.1 Modeling Approach Introduction

Power flow analysis is extremely complex and involves modeling all of the generation, loads and transmission elements (lines, transformers, *etc.*) in an area. The analysis involves removing individual transmission elements and individual generators one at a time to determine if the system will remain reliable with different elements simultaneously out of service. Additional analysis involves taking more elements out of service to determine if the system stays reliable. Because the modeling is so complex, power flow models typically model only one hour in the year in any particular model run.

The overall modeling approach involves:

1. Building models: choosing modeling tools, cases to run, system tests to perform and developing inputs to the model,
2. Testing the models to ensure they will solve,
3. Running the models to identify constraints on the transmission system,
4. Identifying potential solutions for the constraints,
5. Testing the solutions in the model, and
6. Iterating steps 3-5 until all constraints are solved.

In order to create a solved power flow model, the following basic equation must be satisfied:

Generation = Load + Losses + Interchange

Results of the NEEM outputs for each of the three scenarios were used to update the SSI model in the creation of the five different scenario models (or cases) – a peak model for each of the three scenarios and less-than-peak models for Scenarios 1: CP and 2: NRPS/IR. Less-than-peak models were needed for Scenarios 1: CP and 2: NRPS/IR because of their extensive reliance on wind resources. NEEM results provided much of the information needed to develop these models. Information derived from the NEEM scenario results included:

- Generation – Installed generation capacity (MW) and energy (MWh) produced by technology type.
- Load – MW demand by load block representative of certain periods in time. Load Blocks 1 and 13 were utilized in the respective peak and off-peak models. Differences in load block values between scenarios were driven by assumptions contained in the NEEM runs for each of the three scenarios. These load values were "generator bus-bar" demands and, as such, include system losses.
- Interchange – Interchange between NEEM regions as a function of a specified load block.

2.4 Detailed Description of Reliability Modeling

2.4.1 Building Models

Modeling tool – The power flow software used for this effort was the Siemens/PTI Power System Simulator for Engineering (PSS\E) computer program. Generally the PAs used the PSS/E power flow modeling tool for Task 7 & 8 analyses. For Scenario 1: CP, however, given the drastic changes specified to the entire Eastern Interconnection, the PAs first developed models with required transmission options to mitigate the EHV constraints caused by the generation additions and deactivations. The Power System Simulator for Managing and Utilizing System Transmission (PSS\MUST) model was used to model the additional transfer capability called for in the scenario. The PSS\MUST tool produces a report of the First Contingency Incremental Transfer Capability (FCITC) and corresponding thermal loadings of the limiting (thermally constraining) transmission facilities. These thermal loadings were used by the PAs to determine where transmission additions were needed. The other two scenarios (Scenario 2: NRPS/IR and Scenario 3: Business as Usual (BAU) did not require this approach because they were easier to solve.

Choosing system conditions (cases) to model – The model used as the starting point for development of power flow models for Phase 2 work was the SSI model created in Phase 1 of the project. The SSI model was developed for the year 2020. The year reflected in the Phase 2 modeling is 2030. A power flow model is capable of modeling only one hour of the year at a time; thus, planners choose the hour that will provide the conditions that stress the transmission system the most. Transmission planners typically assume that if the transmission system can withstand that hour, it can withstand all of the other 8,759 hours in the year. For the vast majority of times, worst case conditions will be experienced under high load conditions, which are typically found during summer peak hours. Traditionally, only these peak load hours have been utilized in transmission planning. With the advent of significant amounts of wind, however, planners realize that there are also hours when there are low loads and simultaneously high production of wind that create significant and different stresses on the system than those typically realized during the peak hours.

Because of this shift in availability patterns of the system's major energy resource, planners developed an additional power flow model representing periods of higher wind production than seen in the peak hour for Scenarios 1: CP and 2: NRPS/IR, which have very large amounts of installed wind. This was necessary because wind typically produces significantly more wind in the off-peak hours of the year (evenings and nights in spring and fall) than in the on-peak hours and that wind is produced when the electric demand is lower creating different stresses on the system than the peak conditions.

The three scenarios chosen by the SSC in Phase 1 of the project for examination in Phase 2 were:

- Scenario 1: Combined Policies (CP)
- Scenario 2: National Renewable Portfolio Standard/ Implemented Regionally (NRPS/IR)
- Scenario 3: Business as Usual (BAU).

In all, five models were developed and employed to evaluate transmission build-out options in Task 7. A peak and less-than-peak model were used to evaluate both Scenarios 1: CP and 2: NRPS/IR. A peak hour model was used to evaluate Scenario 3: BAU. The transmission solutions for each scenario were based on resolving reliability issues in all of the selected time periods.

A model (case) identification convention was adopted to readily and simplistically identify each model by its scenario (1, 2, or 3) and load block (1 or 13); *e.g.*, Scenario 1: CP would be "S1" and Load Block 13 would be "B13", so the model reflecting off-peak load conditions for Scenario 1: CP would be known as the "S1B13" case. A detailed description of how Block 13 was chosen is included on p. 14 in the "Choosing the Less Than Peak" section.

2.4.2 Testing the Models

To properly integrate generation capacity into the power grid with adequate transmission in place to support that capacity, system performance tests were utilized in the determination of transmission adequacy to support reliable system operation during the two load periods chosen (Block 1 and Block 13). For purposes of this analysis, an "Element" was defined as a generator, transformer, or transmission circuit; a transmission circuit is any component of a transmission line (including DC) between two substations (*i.e.*, circuit breaker, switch, and conductor). Regional criteria were applied for generation interconnections by each PA. Consistent with existing and proposed NERC transmission planning (TPL) standards and the description in the SOPO, the following tests were utilized.

a. **Test 1 (T1):** System Performance with all Elements in Service

   The transmission developed for each of the three scenarios was assessed to ensure there are no 200 kV and above thermal loading or voltage violations identified with all system Elements in service (no contingency). This test is consistent with all Category A contingencies as defined in the currently approved NERC TPL-001-1 standard.

b. **Test 2 (T2):** System Performance Following the Loss of a Single Element

The transmission developed for each of the three scenarios was assessed to ensure there are no 200 kV and above thermal loading or voltage violations identified with the loss of a single Element (single contingency). Additionally, this test provides for the loss of a single component of a 200 kV and above transmission circuit without a fault that results in the open ending of a transmission line. This test is consistent with all Category B contingencies as defined in the currently approved NERC TPL-002-1B standard.

c. **Test 3 (T3):** System Performance Following Loss of a Single Element under Generator Out Scenarios

The transmission developed for each of the three scenarios was assessed to ensure there are no 200 kV and above thermal loading or voltage violations identified with any contingency defined in Test 2, in addition to a generator-out scenario (N-G-1). Each generator across the Eastern Interconnection greater than 500 MW and interconnected at 200 kV or greater will be taken offline individually prior to the N-1 screen of Test 2. This test is consistent with a subset of Category C3 contingencies as defined in the currently approved NERC TPL-003-1a standard.

d. **Test 4 (T4):** System Performance Following the Loss of Multiple Transmission Lines Sharing Common Towers/Structures

The transmission developed for each of the three scenarios was assessed to ensure there are no thermal loading or voltage violations identified with the loss of multiple transmission circuits that share common towers/structures. In general, this does not apply to circuits that only share a minimal number of towers/structures, such as, into and out of substations or other unique situations. This test is consistent with Category C4 and C5 contingencies as defined in the currently approved NERC TPL-003-1a standard.

e. **Test 5 (T5):** System Performance Following the Loss of Multiple Elements as a Result of a Bus Section Fault on Buses 300 kV and Above

The transmission developed for each of the three scenarios was assessed to ensure there are no thermal loading or voltage violations identified with the loss of multiple Elements that result from the normal clearing of a fault on a bus section of voltage of 300 kV or higher. This test is consistent with Category C1 contingencies as defined in the currently approved NERC TPL-003-1a standard.

These tests (T1-T5) were performed on the 200 kV and above system. A full NERC reliability analysis would also include:

- elements lower than 200 kV,
- more detailed analyses including more instances of multiple transmission elements out of service, and

- additional types of analyses such as generator stability and dynamic analysis.

The planners identified transmission that supports inter-regional transfers, as defined in each scenario, for the projected system peak hour load and, where used, for the "less than peak" hour load. All thermal loading and voltage violations identified for facilities at the 200 kV voltage level and higher were mitigated through transmission expansion and not by applying operating guides or curtailing firm transactions.

Facilities located at lower voltage level sites less than 200 kV were not monitored and reported in the analyses unless a particular Planning Authority determined they were important to the higher voltage system. Some select transmission projects were identified at voltages less than 200 kV if the Planning Authority deemed they were necessary for the model. Correction of thermal loading and voltage issues associated with these lower voltage facilities were generally omitted from the work of Tasks 7 and 8, recognizing that this resolution requires specific resource and other detailed configuration information that is typically only known within a near-term planning horizon.

A summary of the tests performed by the planners is shown in Table 2-1.

Table 2-1. System Performance Tests and Criteria

Test	Description	Minimum Criteria to Mitigate	
		Thermal Loading	**Voltage**
T1	No Contingency	> 100% of Rating (Rate A – normal rating of the line which is to be maintained except in certain emergency situations)	< 95% of correct voltage > 110% of correct voltage
T2	Loss of Single Element	> 100% of Rating (Rate B – emergency rating [higher than Rate A] which is allowed for restricted periods of time in emergency situations)	
T3	Loss of Single Element in Conjunction with a Generator Outage		
T4	Loss of Multiple Transmission Circuits that Share Common Towers/Structures		
T5	Loss of Multiple Transmission Circuits that Result from a Bus Fault on Buses Greater than 300 kV		

2.4.3 Determining Inputs to Models

Power flow models must include detailed information on the location of generation, its size, ramp rates, *etc.* For this effort, there were many generation additions and deactivations and all of these needed to be specifically placed in the model. They also need detailed information on the loads or demands that are expected to be served, including locations. Last, they need the existing transmission topology and transfers modeled correctly.

A. Load Information

A key input to power flow models is the amount of load (demand) on the system. Table 2-2 below shows the loads and amount of demand response in each of the power flow models used in the analysis.

Table 2-2. Load and Demand Response

	Load				Demand Response		
Scenario and Block	2030 Generation at System Peak with Losses (MW)	2030 Peak Demand (MW)	2011-2030 Total Peak Growth (%)	Annual Peak Growth Rate (%)	2010 Capacity (GW)	2030 Capacity (GW)	Dispatched in 2030 in Power Flow Cases (MW)
Scenario 1: Combined Policies - Block 1	586,397	565,012	-5.00%	-0.25%	33.1	152	5,216
- Block 13		351,750					0
Scenario 2: National RPS/ Implemented Regionally - Block 1	700,487	673,108	14.00%	0.70%	33.1	71	0
- Block 13		421,692					0
Scenario 3: Business as Usual - Block 1	718,433	690,492	17.00%	0.85%	33.1	71	0
Note: "2030 Peak Demand" reflects customer demand at the meter while "2030 Generation at System Peak with Losses (MW)" reflects the customer demand at the meter plus losses on the transmission system.							

Demand response (DR) and energy efficiency (EE) were particularly high in Scenario 1: CP. The DR and EE components are described as follows:

- Economically achievable energy efficiency, demand response, distributed generation and smart grid resources used to meet power needs. These are the first resources evaluated and deployed by the model.
- Overall energy demand is drastically reduced and new technologies are available for customers and utilities to manage demand to meet power needs in real time.
- Energy efficiency and demand response would meet 20% of energy resource needs annually by 2030.

Peak load forecast values are "before DR". Increased levels of DR directly offset the need for generation resources to meet installed capacity reserve requirements. In Phase 1, DR was modeled as pseudo-generation. Each of these DR pseudo-generators had a high variable cost associated with it and thus did not generally assist in meeting energy requirements. Thus, DR primarily served to reduce the need for generation expansion and also resulted in fewer transmission additions.

NEEM included DR in the choice the program made for new installed capacity resources, offsetting the need for generation capacity and resulting in a different generation resource mix than if DR were not available. The DR was reflected in the power flow model by having less generation additions due to the DR MW than would otherwise be needed.

EE was separated from DR in Phase 1 and in the Phase 2 load flow models. In order to reflect EE in the model, peak load forecasts were decreased by 1% per year in Scenario 1: CP and the reductions were done on a load ratio share basis across the entire Eastern Interconnection.

Losses - In order to separate losses from load, as given in the NEEM output, the PAs calculated the system loss percentage for each area modeled in the SSI model and applied that same percentage for each area in the Phase 2 scenario models. This was a one-time assumption and was not iterative.

B. Generation Additions and Deactivations Methodology

The overall process in building the five models was to utilize the output information from the NEEM resource allocation models in the respective power flow models. One of the first issues that arose was the deactivation of existing generating units and location of new generating units. The outputs from NEEM indicated how much generation needed to be added, what types of generation (*e.g.*, coal, combined cycle, wind) needed to be added to the model and the NEEM region in which they were added. Similarly, NEEM provided the same information for de-activations – the amount, type and NEEM region for the deactivations.

A power flow model, however, has the entire transmission system modeled and the generators need to be placed in a specific location (*i.e.*, on a specific “bus”) in the model. Thus, the PAs, in collaboration with stakeholders, needed to physically locate the additional generation within the power flow model and to also specify which specific existing units would be deactivated in the model.

<u>Generation Additions</u>

The PAs sited incremental generation (beyond that in the SSI model) using the following guiding principles:

1. Non-Renewable Unit Additions

    - Nuclear generation was located in the model according to regional practice and best available planning information, *e.g.*, if there was space at an existing nuclear station in a particular region and additional nuclear generation was called for, the additional nuclear capacity was located at that site;
    - Where possible non-renewable generation capacity was sited at existing generation sites where generating units had been deactivated by the PAs.

New generation was added at that site up to the MW capacity of the deactivated generation previously installed at that location. This can be thought of as a MW swap at the existing generation site.

2. Remaining Non-Renewable Resources and Renewable Additions

   For all non-renewable resources that could not be located at existing sites and for new renewable resources, each Planning Authority located generating resources in its region based on available regional information, which includes the following:

   - Current generation queue data
   - Transmission availability
   - Renewable resource potential assessments, such as MISO's Regional Generator Outlet Study
   - Generation expansion siting studies
   - Energy zone assessments
   - Other public information, *e.g.*, where people were proposing to build generation.

<u>Generator Deactivations</u>

1. For specific large coal units (200 MW or larger), MRN-NEEM indicated whether the specific unit was active or needed to be deactivated.

2. For smaller units (below 200 MW for coal as well as other fossil units) the MRN-NEEM model indicated the amount, type and NEEM region of generation that needed to be deactivated. Rather than choosing specific power generators within the NEEM region to deactivate, the PAs reduced all generation of a specific type by the same percentage. For example, if 500 MW of combined cycle plants were to be deactivated in a NEEM region with 2,000 MW of combined cycle plants, each plant's capacity would be reduced by 25% in the power flow and production cost models.

3. To the extent steps #1 and #2 above did not provide sufficient specific deactivation information the following process was used:

   a. <u>First Stack of Unit Deactivations: units greater than 40 years old and capacity less than 400 MW</u>

      i. Units with no pollution controls (starting with the smallest plants and working up to the larger plants)

      ii. Units without SO_2 controls and Fabric Filter (FF) baghouses for particulates (in order of smaller MW to larger MW size)

iii. Units without Selective Catalytic Reduction (SCR) and FF (in order of smaller MW to larger MW size)

iv. Units that only needed one of the three controls to be compliant (in order of smaller MW to larger MW size).

b. Second Stack of Unit Deactivations: units less than 40 years old and greater than 400 MW

i. Units with no pollution control retrofits. The "no control" units were deactivated starting with the smallest plants.

ii. Units lacking SO2 control but having one other control such as SCR or FF. Order the "no SO2 control" units from smallest to largest deactivating the smallest first.

iii. Units lacking one of the remaining controls: Units that have SO2 control but lack either SCR or NOX controls. Order the "SO2 controlled" units from smallest to largest deactivating the smallest units first.

c. Third Stack of Unit Deactivations

Units with all of the above retrofits. Smaller units in this group are assumed to have the least economy of scale. Order the units from smallest to largest deactivating the smallest units first.

Exceptions for data issues, or other agreed upon justification, were addressed case-by-case.

Choosing the "Less Than Peak" Case

As described above, transmission planners examine the system under anticipated "worst case" conditions. A summer peak hour power flow model was developed for use with the SSI model as the starting point. Load Block 1 (B1) loads from the NEEM results were used in the development of the three summer peak hour transmission models used in Task 7. For Scenarios 1: CP and 2: NRPS/IR, the TOTF also selected a "less than peak" case, using Load Block 13 of the NEEM results. This block had low loads and high wind generation, creating significant and different stresses on the system. Below is a detailed description of how Load Block 13 was chosen.

The most significant factors considered in selecting the "less than peak" model were:

- High renewable resource generation
- High output of renewable resources in the West when load is increasing in the East
- Consistency with NEEM results

- Degree of system stress created by combination of higher wind and lower loads.

Because power flow models only model one hour of the year, one NEEM output hour needed to be chosen. However, NEEM does not deal in single hours but works with groups ("blocks") of hours. The hour for the power flow model was selected by choosing a representative ("Shoulder") load block within the "Shoulder" season with its typically lower loads and choosing an hour within that block with a large amount of wind dispatched.

"Shoulder" hours occur during the months of March, April, October and November. Winter hours are in December through February and summer hours include May through September. In NEEM, the hours were sorted by season and by the amount of load into tiers within that season, with the top tier being the highest loads and the bottom tier being minimum loads. Load blocks for the Shoulder season are shown in Table 2-3.

To choose the representative load block within the Shoulder season, the ratio of the average load in each block to the total system peak was calculated. The average percentage of load to peak across all regions and Shoulder blocks is 0.625 (or 62.5% of total system peak load, which is 100%). Block 13 is closest to the overall average, and experiences this load 600 hours of the year; therefore an hour from Block 13 was selected to represent the less than peak case.

Table 2-3. Load Block Characteristics

Shoulder Load Blocks	Number of Hours in Load Block	% of Total Shoulder Hours in Load Block	Average pu-of-Highest Load Across All Regions
Block 11	25	0.9	0.698
Block 12	200	6.8	0.656
Block 13	600	20.5	0.622
Block 14	900	30.7	0.580
Block 15	1,203	41.1	0.568
	Total Hours 2,928		Average = 0.625

2.4.4 Testing the Models

Power flow models identify overloads on the system and voltages that are too high or too low. All of these conditions, if they are severe enough, can cause the system to collapse. To do the tests listed above, the PAs first needed to create models that would "solve" or "converge". The models use an iterative process to come to a solution that balances all generation and loads with flows along individual transmission lines. In some cases, if the transmission system is too stressed in the model, the model will not converge.

2.4.5 Run Models to Identify Constraints

Once the models solved with the generation additions and deactivations, the large-scale inter-regional transfers specified by the NEEM model were incrementally added to the load flow case. The PAs added transmission, upgraded and re-conductored lines, or added voltage support to address any congestion or voltage problems on lines above 200 kV. Transmission constraints on elements less than 200 kV were monitored. Typically constraints on the lower voltage system were not addressed unless the issues were severely affecting the 230kV and above system and/or the area did not have the necessary supporting 230kV and above infrastructure.

2.4.6 Identify Solutions for Constraints

Transmission planners develop solutions based on what transmission lines/elements are overloaded or have voltage issues and how significant the overload or voltage issue is. The objective is to "right-size" the solution to the issues in the model and there are times when it is more cost-effective to choose a larger solution that solves more issues rather than many smaller solutions.

a. System Performance Tests

System Performance Tests 1 and 2 were used in the Task 7 evaluation of Scenarios 1: CP, 2: NRPS/IR and 3: BAU. These tests performed an N-0 and N-1 contingency analysis of the scenario models. In Scenarios 1: CP and 2: NRPS/IR, where two power flow models were employed to represent each of the scenarios, a combined analysis was performed such that one transmission build-out option would be identified. The results of these tests, as used in Task 7 to (1) interconnect new generation resources and (2) test for, and relieve, constraints created by these added resources, can best be conveyed and visualized through the use of EI maps that display the end result of multiple passes in each Scenario's analysis.

The transmission planners added transmission to solve the largest constraints first and then examined the results of that model run to see what constraints were left. Each of these runs is known as a "Pass." Each subsequent pass solved more and more constraints until no constraints were left. Transmission elements are supposed to be loaded at no more than 100% of their carrying capacity. In some cases, transmission elements were overloaded by many times their carrying capacity. Typically, not all of the constraints can be solved in a single model run.

Scenario 1: CP needed the most passes to eliminate all of the identified constraints because it had the largest amount of additional transfer capability needed. Scenario 3: BAU needed the fewest passes to solve all the identified constraints.

b. High voltage Direct Current (HVDC) Consideration Process

The three scenarios selected for Phase 2 analysis were initially evaluated contemplating AC line solutions as the need for transmission improvements were identified. Following this initial evaluation, HVDC solutions were evaluated as potential solutions based on the following guidelines:

- The solution identified is a long overhead transmission line (typically over 400 miles) carrying a large amount of power. This is the most likely situation to arise in this analysis.

- The solution is an underground or undersea cable longer than 30 miles. Underground or undersea AC conductors have significantly higher losses than HVDC lines; if the cable is underground or undersea and is longer than 30 miles, it becomes more cost-effective and reliable to choose HVDC lines over AC lines even with their higher cost.

- Power transfer between asynchronous systems is identified as a possible solution. This would require a back-to-back HVDC system, in which there is no transmission line, but the HVDC connection acts as a control between the two AC systems. Hydro-Quebec and ERCOT are systems that use back-to-back HVDC to connect with other systems.

There are, however, a number of considerations to evaluate in determining whether HVDC or EHV AC is the preferred solution. As stated previously, HVDC systems can transmit large amounts of power over long distances with no taps very well. There are no reactive losses, and the line length is limited ultimately only by resistive losses. The HVDC power transfer can be controlled precisely, which is a desirable feature when injecting large amounts of power into a system from a far distance. HVDC systems can directly transfer the intermittent nature of renewable resources to a remote region, allowing the operational flexibility and reserves of that region to help follow the swings in renewable generation output. They can improve the stability of the AC network, particularly in significant renewable exporting regions. Additionally, HVDC transmission line conductor costs are less, since only two conductors are needed, vs. three for AC lines. HVDC systems require strong AC systems at both ends to work properly.

EHV AC transmission can deliver equivalent amounts of power the same distances, using switching stations every 200 miles to provide reactive compensation. An AC transmission line integrates well with the existing power system, and power can easily be tapped from the line where needed.

2.4.7 Test Solutions

Once potential solutions are identified, transmission planners run the load flow models with the potential solutions to determine if they mitigate the constraints and to ensure they don’t cause additional constraints.

Steps 2.4.5 through 2.4.7 were repeated until all the constraints being addressed in this analysis were eliminated.

2.5 Results – Task 7

The results of Task 7 which involved developing generator interconnections and Reliability Tests 1-3 show significant differences in the buildout between the three scenarios. The maps depicting transmission additions contain both new lines and reconductored/upgraded lines.

2.5.1 Scenario 1: CP

The integration of capacity resources derived from the Scenario 1: CP NEEM output necessitated the addition of 365 generation interconnection projects in the scenario models. These interconnections are seen in Figure 2-1. Constraints on the system caused by the generation changes can be seen in Figure 2-2. Six passes of power flow analysis were performed for Scenario 1: CP to evaluate the integration of new generation into the power grid and to alleviate constraints as determined by System Performance Tests 1 and 2. Five hundred (500) constraint relief projects were required to mitigate constraints in the power grid realized from these interconnections. The resulting transmission build-out for Scenario 1: CP included the addition of six HVDC lines as shown in Figure 2-3.

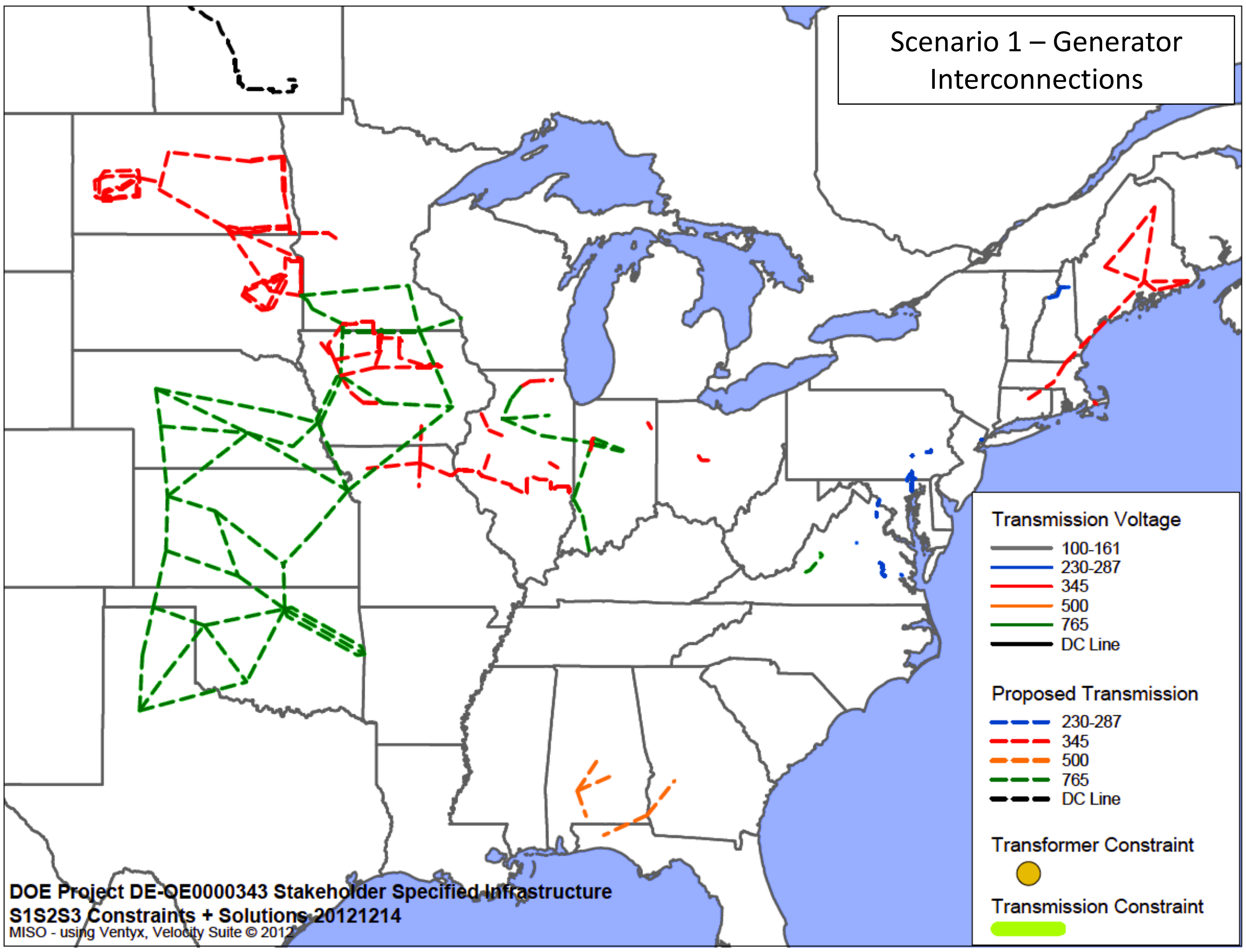


Figure 2-1. Scenario 1: CP: Generation Interconnections

The significant amount of wind in this scenario in the MISO and SPP regions necessitated the development of large 345 kV and 765 kV collector systems in those regions. A 345 kV collector system was also needed in the northeast. All of these reinforcements were needed to solve the model with the generation additions and deactivations, particularly the wind located in the MISO and SPP regions. These additions were needed before the transfers were added to the model.

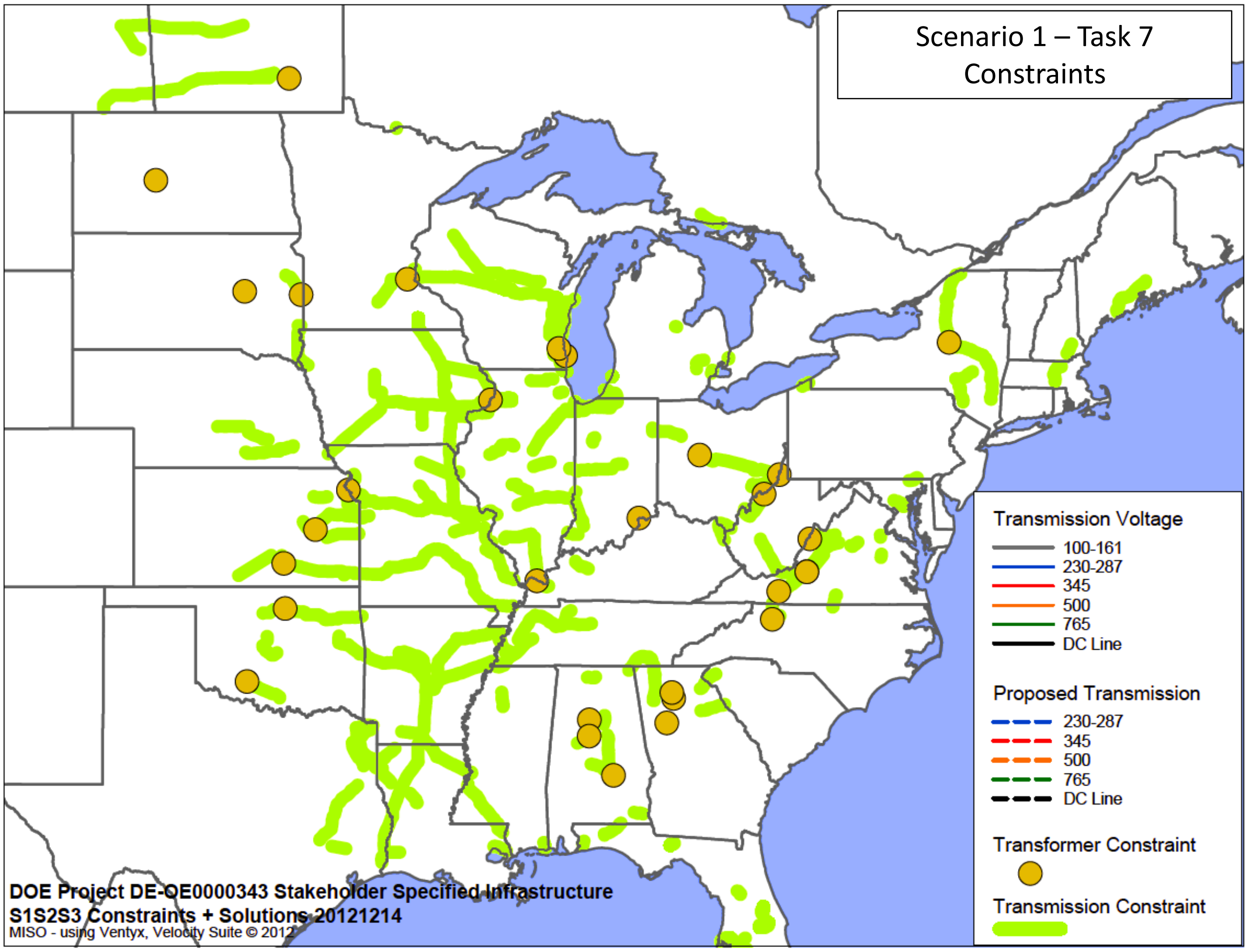


Figure 2-2. Scenario 1: CP: Task 7 Constraints

The generator interconnections allowed the model to solve, but resulted in significant constraints on the system as the system tried to transfer the power as specified by the NEEM model. The most constraints show up in the MISO, SPP and Entergy regions with some in the northeast.

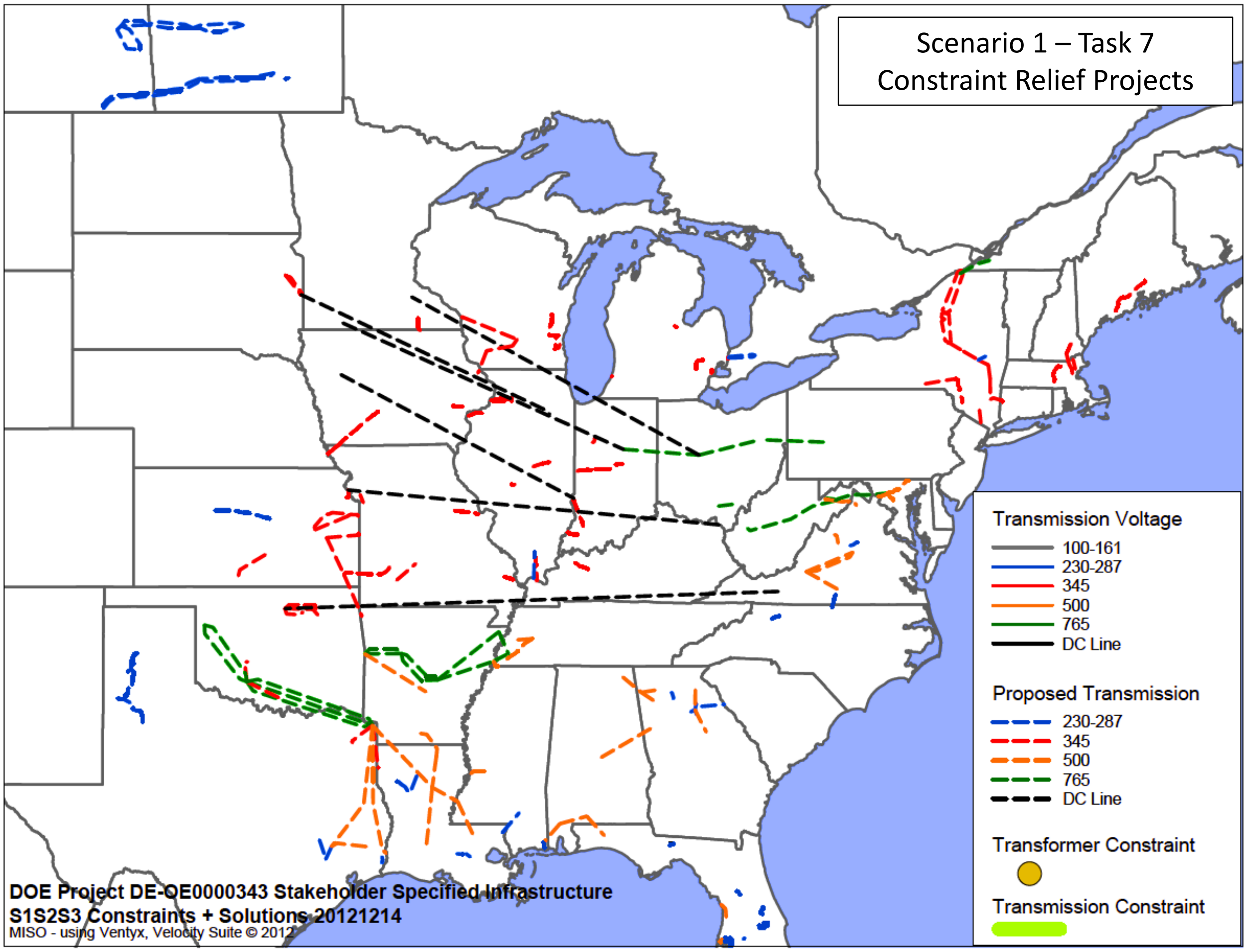


Figure 2-3. Scenario 1: CP: Task 7 Constraint Relief

In solving the significant constraints in the model, the EIPC PAs found that building a larger AC system was not going to be sufficient. To move the large amounts of power from the Midwest over long distances to the east, HVDC lines were needed. HVDC lines were added until the most significant constraints were solved. Extensive time and effort was spent to determine the right number of 500 kV HVDC lines and their end points. Each of the lines was removed from the model to determine whether other lines would overload if it were not there. Ultimately, it was determined that six HVDC lines, each capable of carrying 3,500 MW, were needed for a reliable system. In addition, there were still significant amounts of 765 kV, 500 kV and 345 kV AC lines that were needed to maintain reliability. The additions in the model were required to get both reliability cases (peak and off-peak) to solve.

The maps above shows only the new facilities added to the system. In addition, over 4,300 miles of lines ranging from 115 kV to 345 kV also needed to be reconductored or upgraded; both new and reconductored/upgraded lines are depicted in Figure 2-3.

2.5.2 Scenario 2: NRPS/IR

The integration of capacity resources derived from the Scenario 2: NRPS/IR NEEM output necessitated the addition of 295 generation interconnection projects in the scenario models.

These interconnections are seen in Figure 2-4. Constraints on the system caused by the generation changes can be seen in Figure 2-5. Six passes of power flow analysis were performed for Scenario 2: NRPS/IR to evaluate the integration of new generation into the power grid and to alleviate constraints as determined by System Performance Tests 1 and 2. Over 200 constraint relief projects were required to mitigate constraints in the power grid realized from these interconnections. These projects can be seen in Figure 2-6.

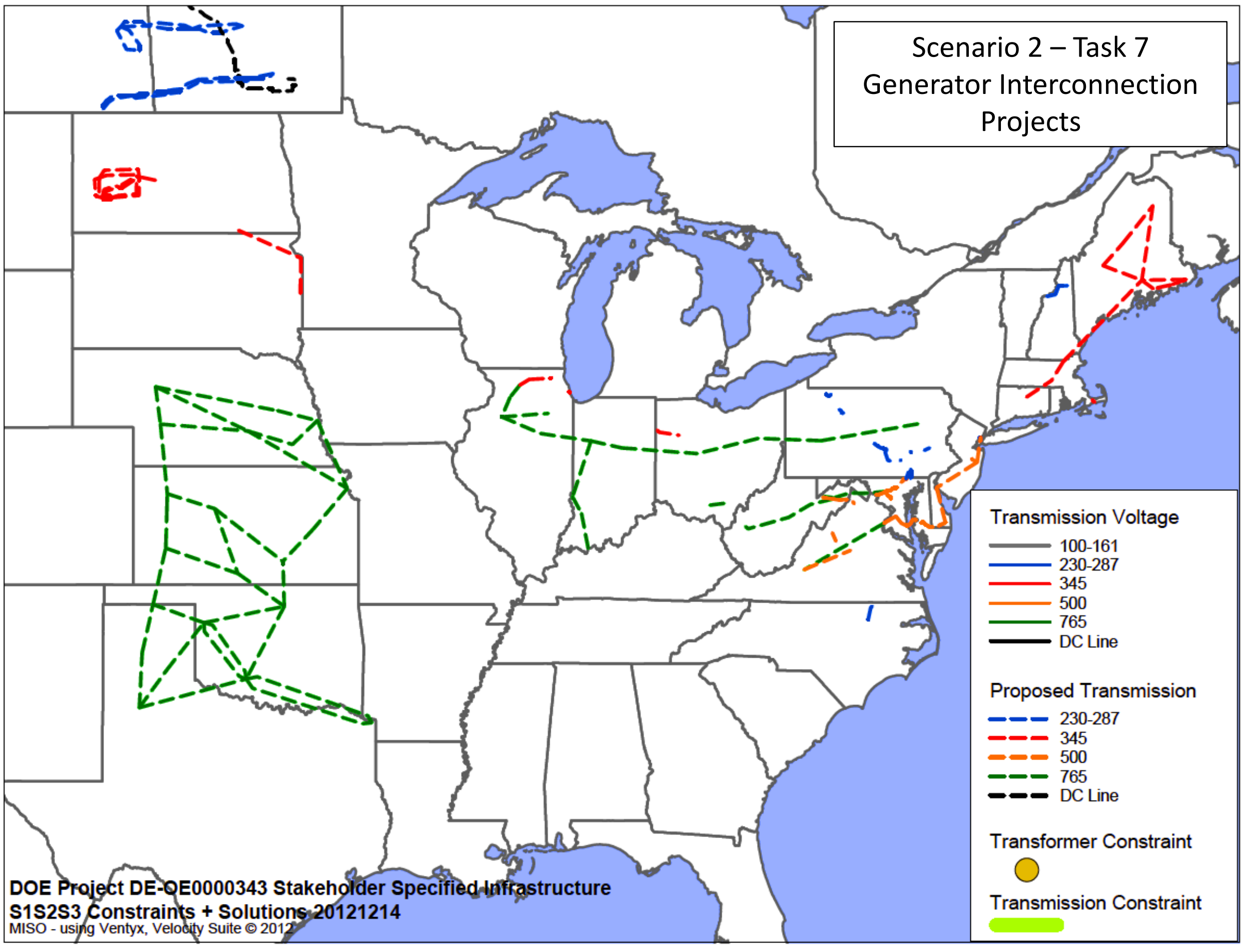


Figure 2-4. Scenario 2: NRPS/IR: Generation Interconnections

Like Scenario 1: CP, Scenario 2: NRPS/IR also had significant amounts of wind, although not as much as in Scenario 1: CP. The additional wind created a need for a 765 kV collector system in the SPP region; because the wind sites were essentially the same in the SPP region, the collector system was also the same. In addition, 345 kV collector systems are needed in MISO and ISO-NE and 765 kV lines to move the power from Illinois to points east within PJM; 765 kV lines were also needed in Virginia and West Virginia, along with 500 kV lines from the Virginias through Maryland, Delaware and New Jersey.

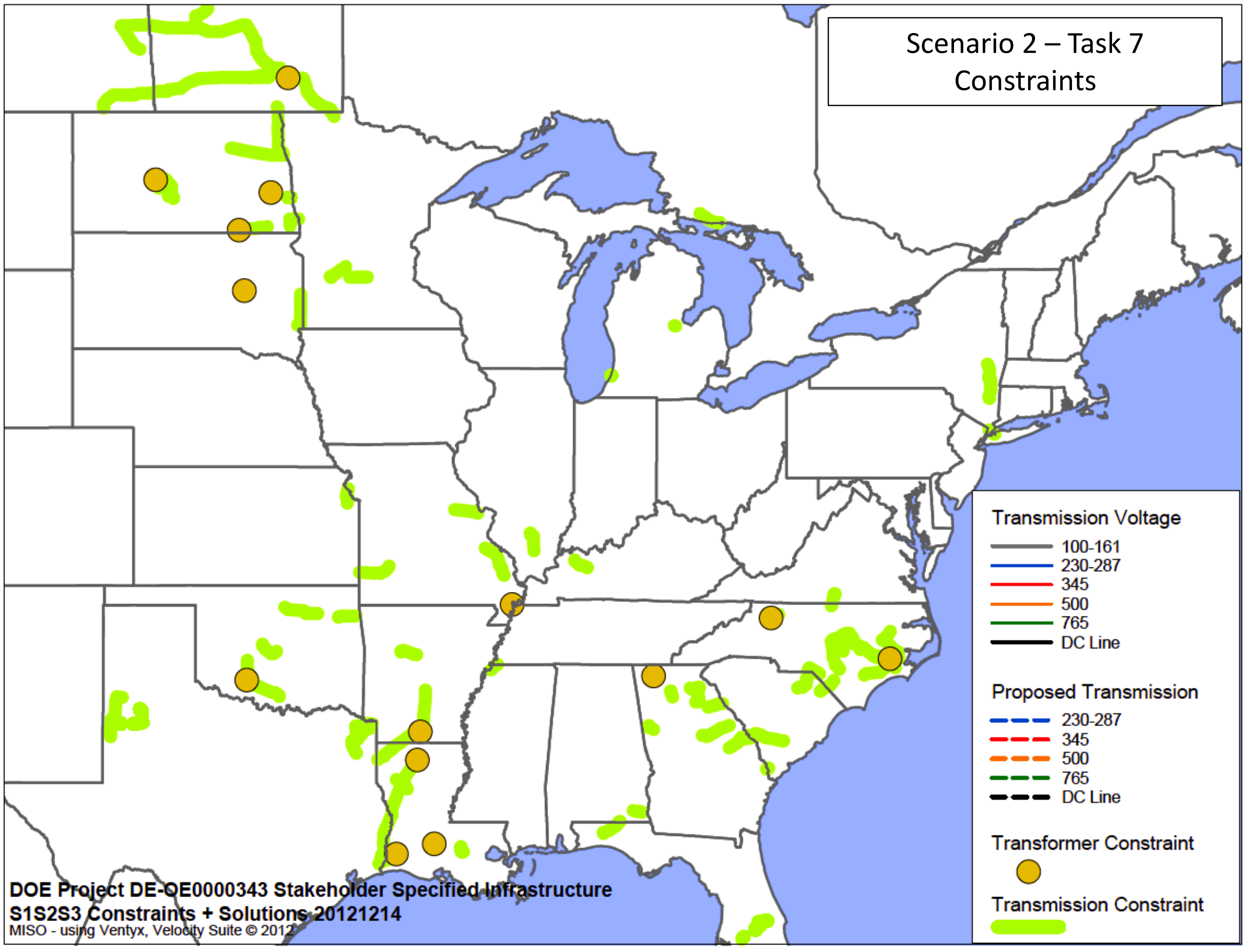


Figure 2-5. Scenario 2: NRPS/IR: Task 7 Constraints

Consistent with Scenario 1: CP, the need to move the power from the west to the east created constraints, mostly in the Midwest. Comparatively, however, the constraints encountered in Scenario 2: NRPS/IR were far fewer than those occurring in Scenario 1: CP. These constraints are in the SPP, Entergy and MISO regions with some additional constraints in the southeast.

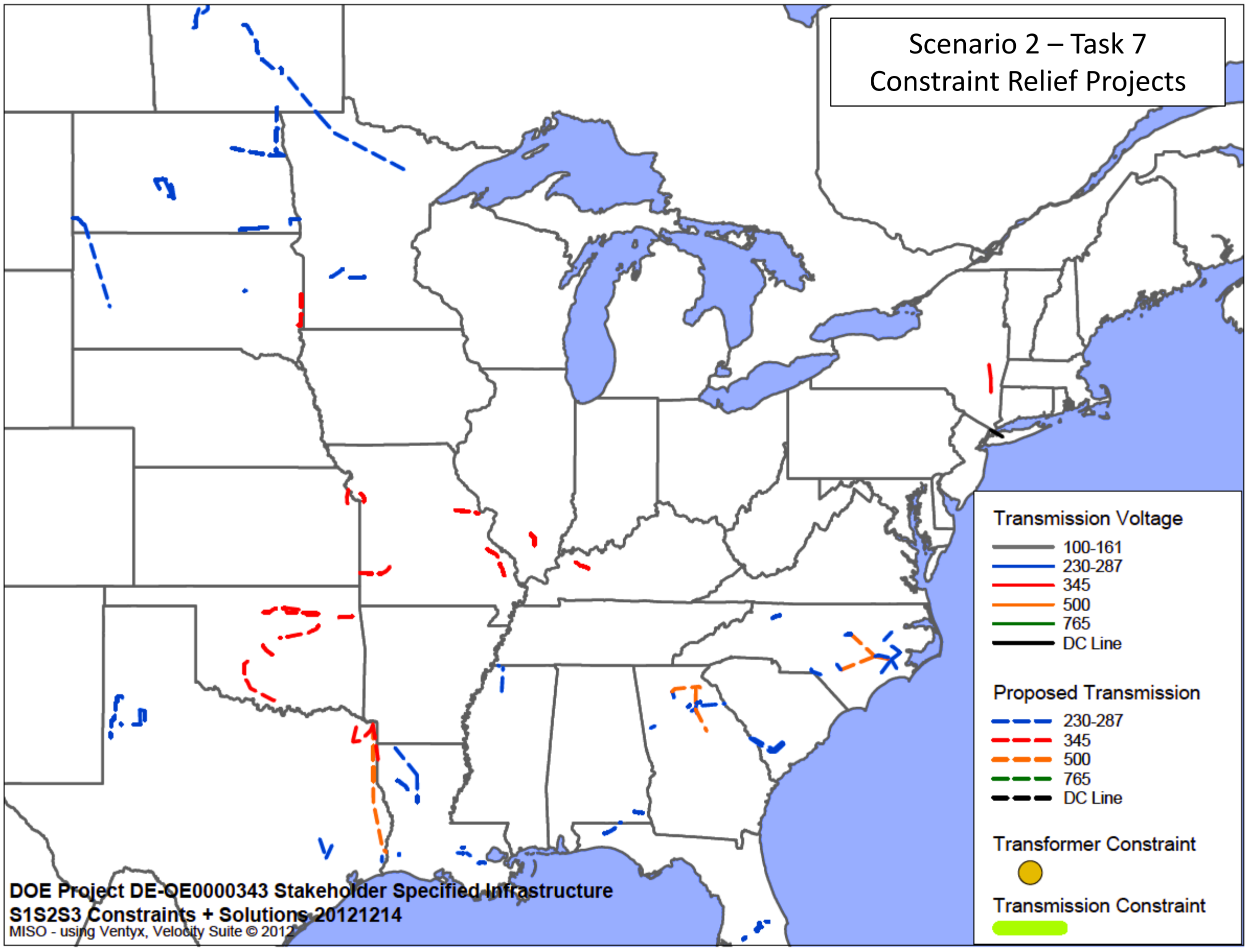


Figure 2-6. Scenario 2: NRPS/IR: Task 7 Constraint Relief

Because of the much smaller number of constraints in Scenario 2: NRPS/IR, there were fewer projects needed to alleviate the constraints and those projects were at lower voltages. Lines added ranged mostly from 230 kV to 345 kV with a few 500 kV additions in the southeast.

In addition to the new lines, over 2,600 miles of existing transmission lines needed to be reconductored or upgraded. Both new and reconductored/ upgraded lines are depicted in Figure 2-6 above.

2.5.3 Scenario 3: BAU

The integration of capacity resources derived from the Scenario 3: BAU NEEM output necessitated the addition of 90 generation interconnection projects in the scenario models. These interconnections are seen in Figure 2-7. Constraints on the system caused by the generation changes can be seen in Figure 2-8. Four passes of power flow analysis were performed for Scenario 3: BAU to evaluate the integration of new generation into the power grid and to alleviate constraints as determined by System Performance Tests 1 and 2. Two hundred-eighty (280) constraint relief projects were required to mitigate constraints in the power grid realized from these interconnections. The resulting transmission buildout for Scenario 3: BAU is shown in Figure 2-7.

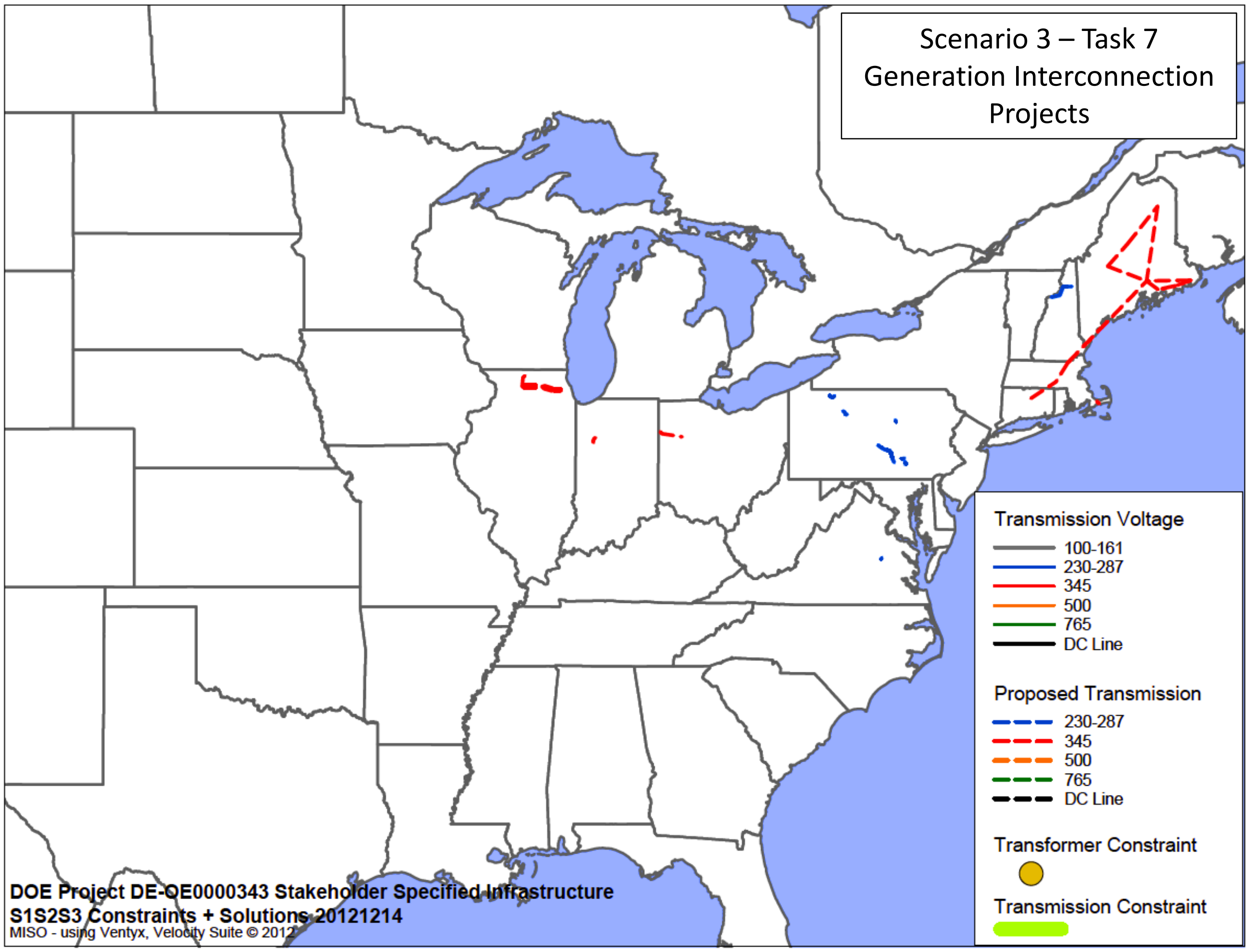


Figure 2-7. Scenario 3: BAU: Generation Interconnections

Scenario 3: BAU had no required additional transfers between NEEM regions that went beyond the limits in the SSI case and new generation was placed first on brownfield sites where generation had been deactivated in the model. Because of these factors Scenario 3: BAU required fewer new transmission projects to support the interconnection of new generation, especially when compared to the generation interconnection projects required by Scenarios 1: CP and 2: NRPS/IR. The most significant single addition is the 345 kV in the ISO-NE, while additional 765 kV and 345 kV lines are needed in Illinois to support generation interconnection.

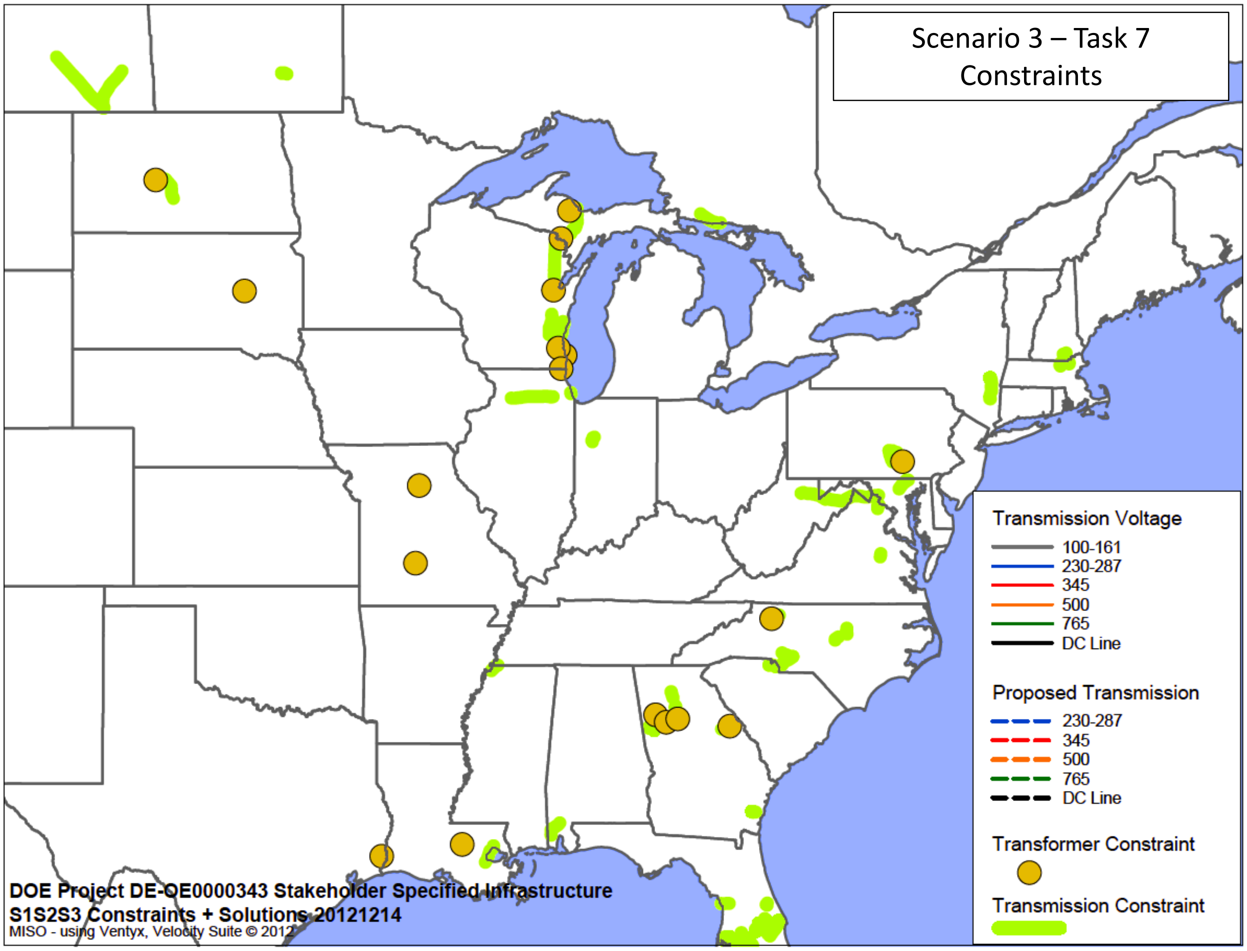


Figure 2-8. Scenario 3: BAU: Task 7 Constraints

Remaining constraints in Scenario 3: BAU were mostly in the Wisconsin/Illinois area and the Virginia/West Virginia areas with scattered transformer constraints.

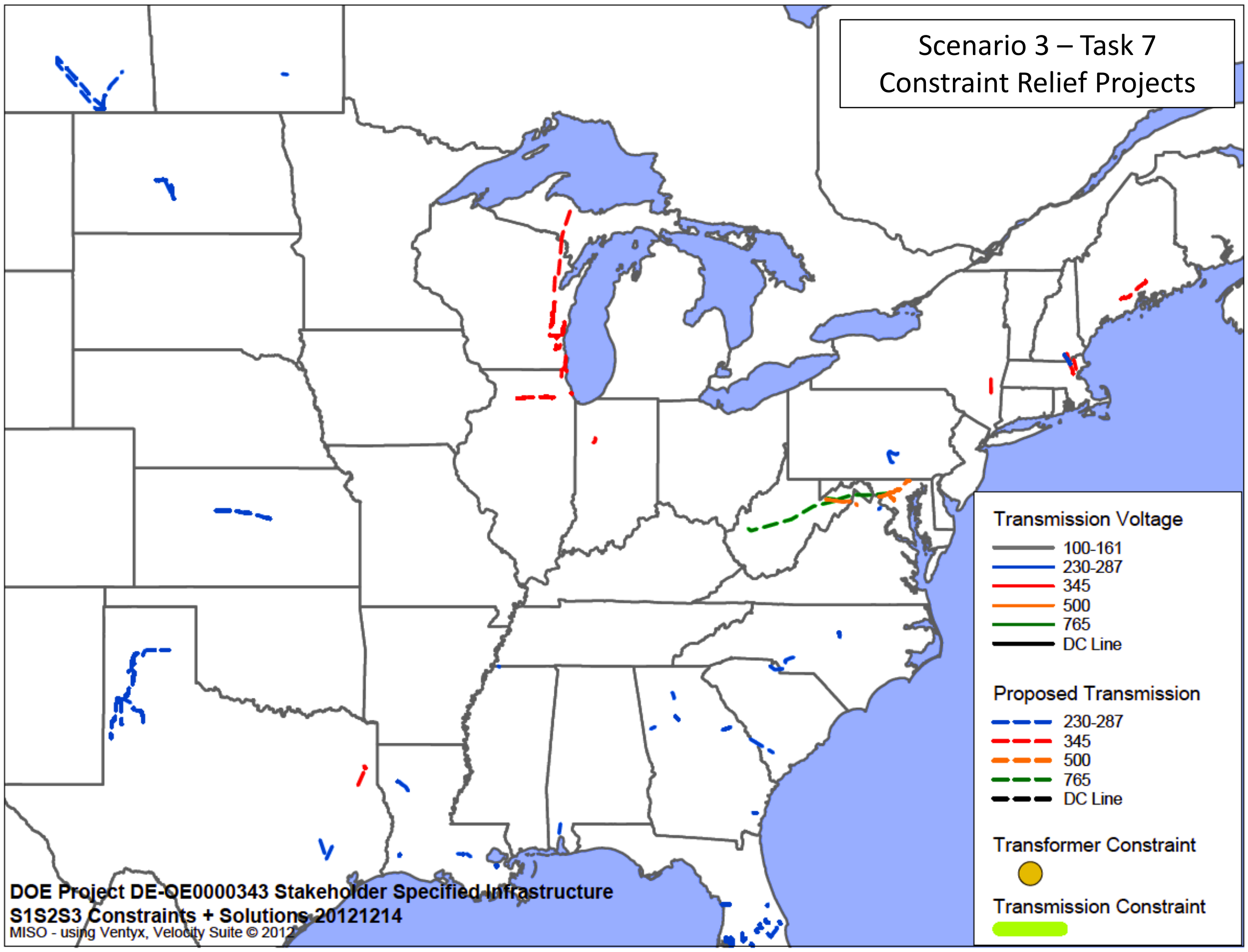


Figure 2-9. Scenario 3: BAU: Task 7 Constraint Relief

To relieve the remaining constraints in Scenario 3: BAU, a 765 kV line was added in the Virginia/West Virginia area, 345 kV lines were added in the Wisconsin/Upper Michigan area and 230 kV lines were added in North Dakota and Saskatchewan, Canada.

In addition to the new lines added, over 2,500 miles of existing transmission lines needed to be reconductored or upgraded. Both new and reconductored/upgraded lines are shown in Figure 2-9.

3 Reliability Results – Task 8

3.1 Task 8 Results

Task 8, as discussed in the Introduction and in the Task 7 description, involved additional reliability tests to ensure that the transmission options developed in Task 7 could meet NERC criteria involving bus outages, common tower outages and combinations of a generator and transmission element being out of service (Test 4 and Test 5). These additional reliability tests resulted in some further transmission lines and upgrades. Following the Task 7 trajectory, there were more elements added in Scenario 1: Combined Policies (CP) than Scenario 2: National Renewable Portfolio Standard/ Implemented Regionally (NRPS/IR)and more elements added in Scenario 2: NRPS/IR than in Scenario 3: Business as Usual (BAU). Figure 3-1 is a map of the line and transformer constraints that resulted from the Task 8 analysis and Figure 3-2 shows the transmission additions that were needed to solve them.

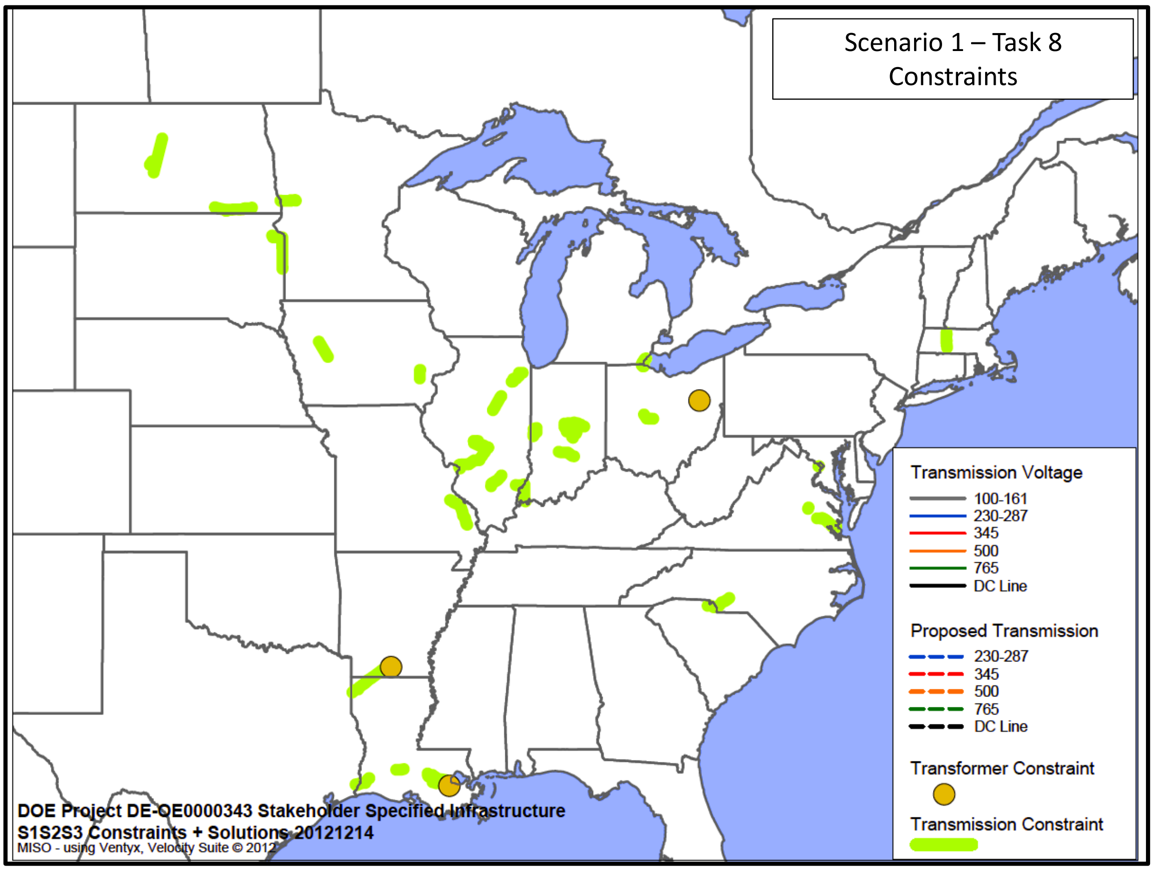


Figure 3-1. Scenario 1: CP: Task 8 Transmission Constraints

Constraints show up mostly in the MISO, PJM and Entergy areas with a few constraints scattered elsewhere. The transmission additions needed to alleviate those constraints are shown in Figure 3-2.

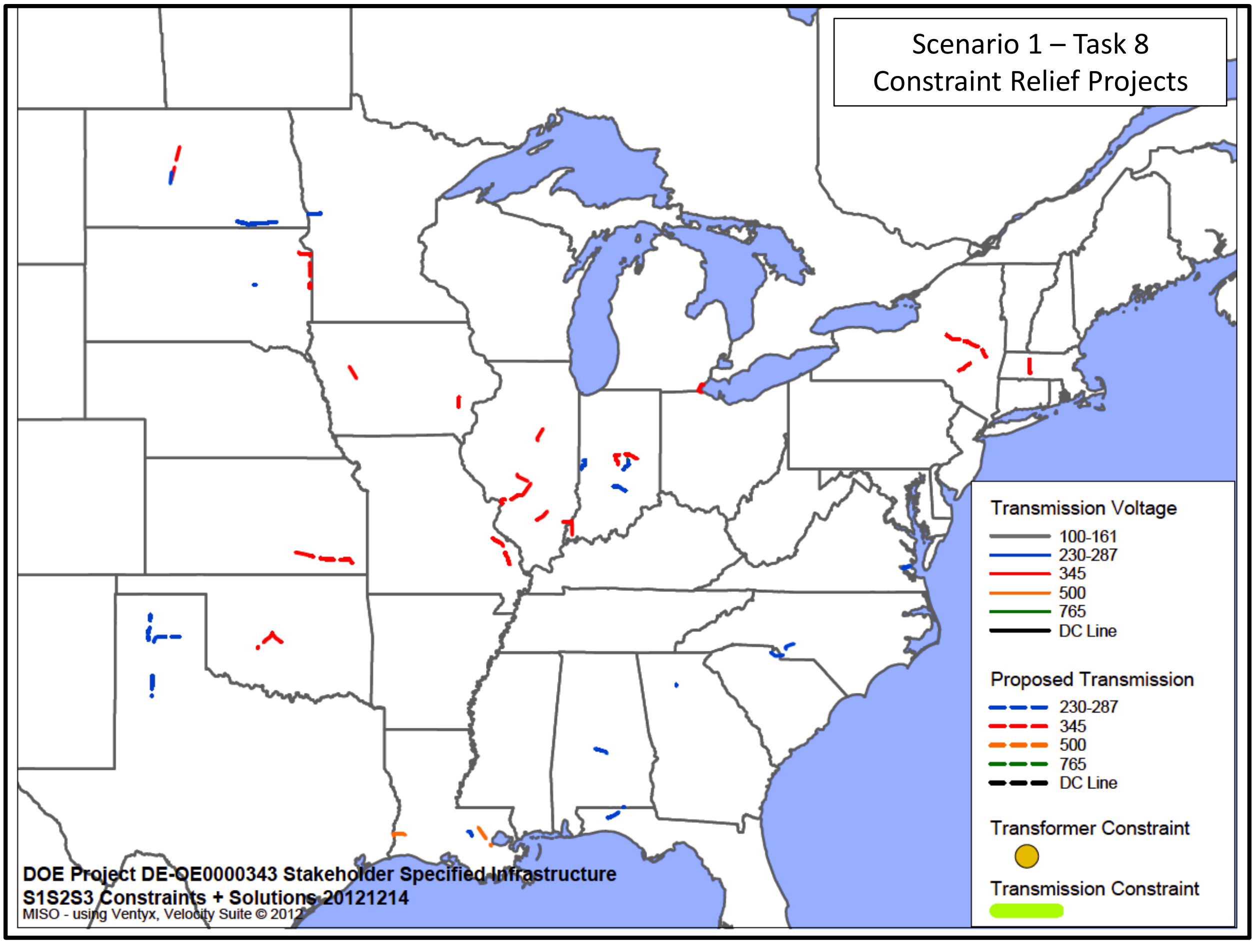


Figure 3-2. Scenario 1: CP: Task 8 Transmission Additions

Transmission enhancements are needed in many areas for Scenario 1: CP. Lines added included 230 kV and 345 kV lines in the MISO-W area and in PJM; 345 kV lines were needed in New York in Massachusetts as well to maintain reliability. In total 85 constraint relief and 40 voltage support projects were needed to address transmission issues identified in Task 8 analysis. Most of these projects were upgraded or re-conductored lines. Both new and reconductored/upgraded lines are shown in Figure 3-2.

Scenario 2: NRPS/IR had very few additional constraints from the Task 8 analysis. These are shown below in Figure 3-3.

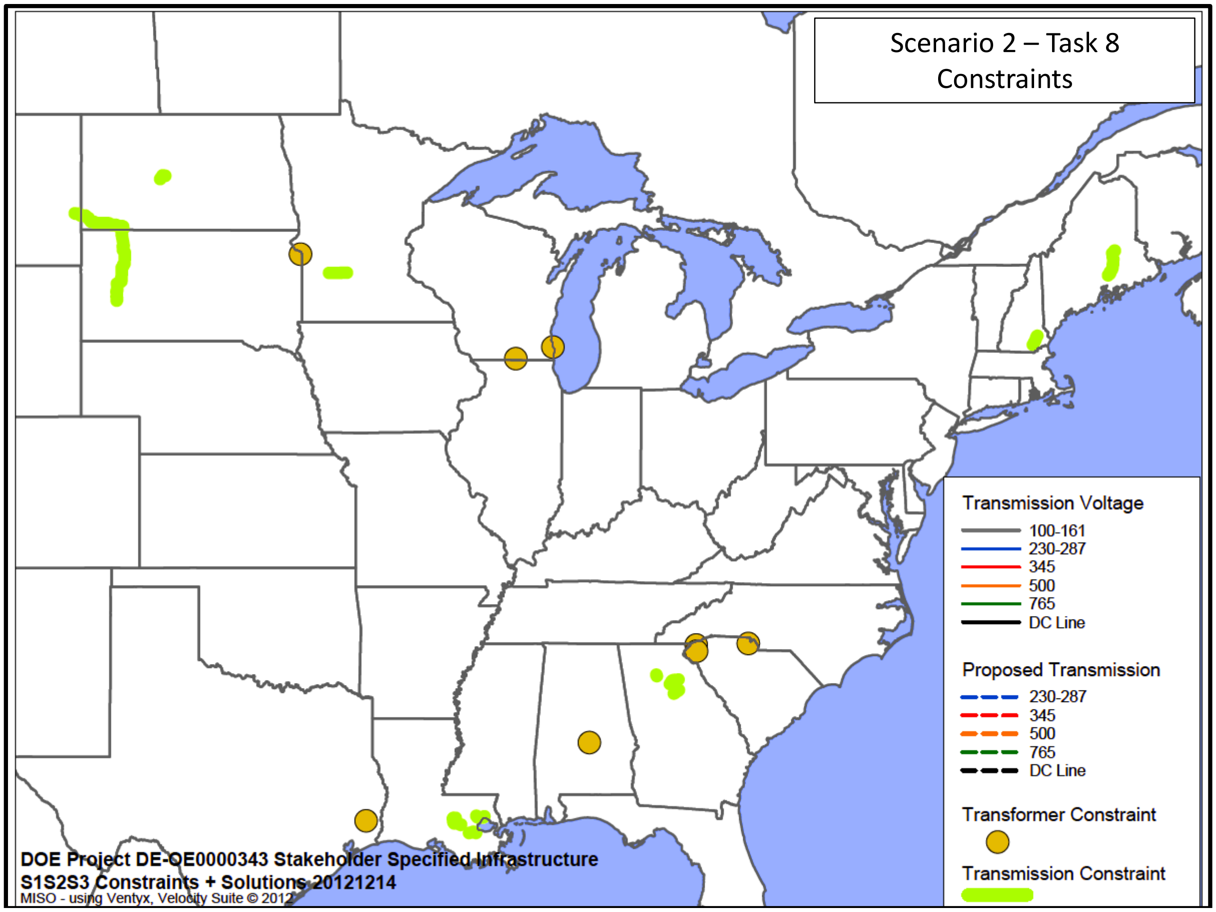


Figure 3-3. Scenario 2: NRPS/IR: Task 8 Constraints

Very minor constraints showed up in MISO, Entergy, the Southeast and ISO-NE. The transmission additions to relieve the constraints are shown in Figure 3-4 below.

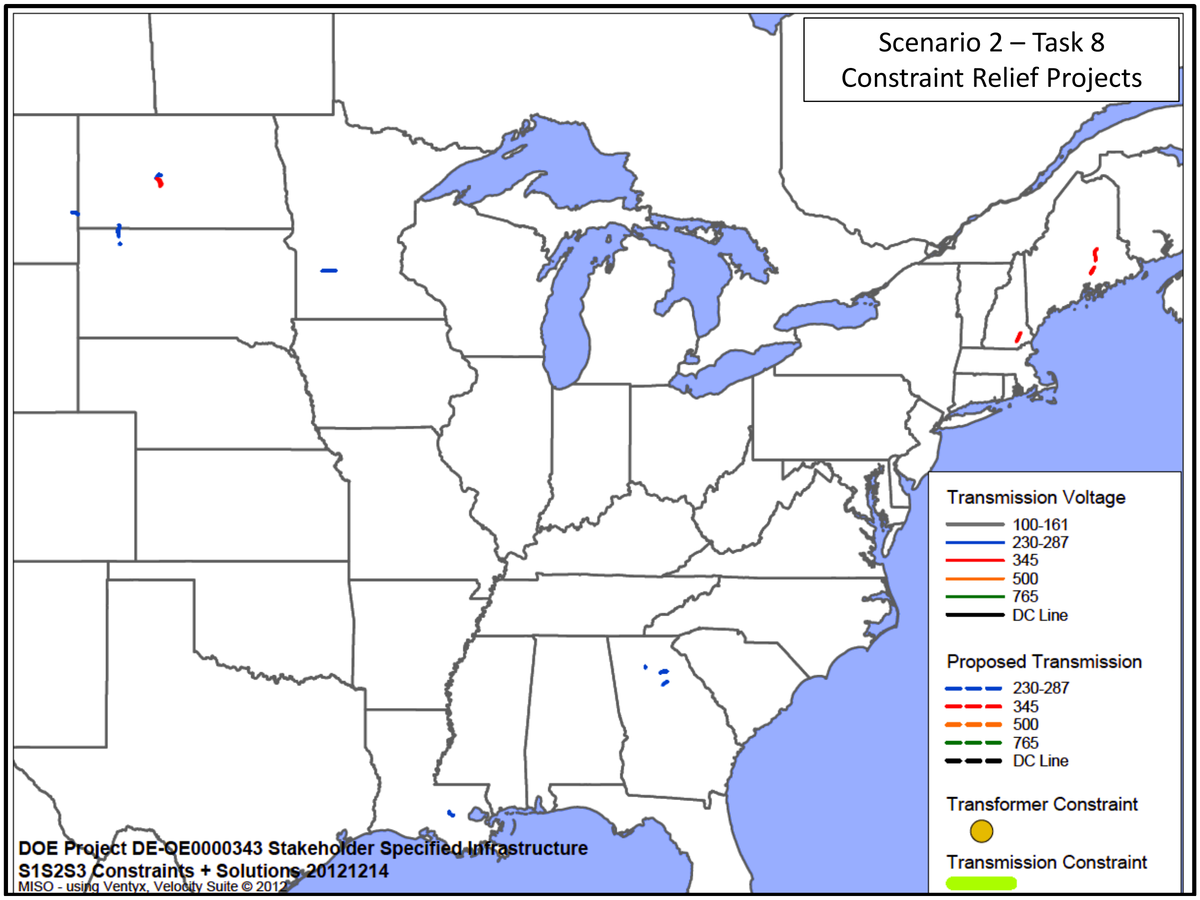


Figure 3-4. Scenario 2: NRPS/IR: Task 8 Additional Transmission

A few additions were made in the MISO, ISO-NE and southeast areas. Overall, 65 thermal constraint relief and five voltage support projects were needed to address transmission issues arising from Task 8 analysis. Most of these projects were upgraded and re-conductored lines. New lines and reconductored/ upgraded lines are shown in Figure 3-4.

Scenario 3: BAU also had few additional constraints as a result of Task 8 analysis. The constraints are shown below in Figure 3-5.

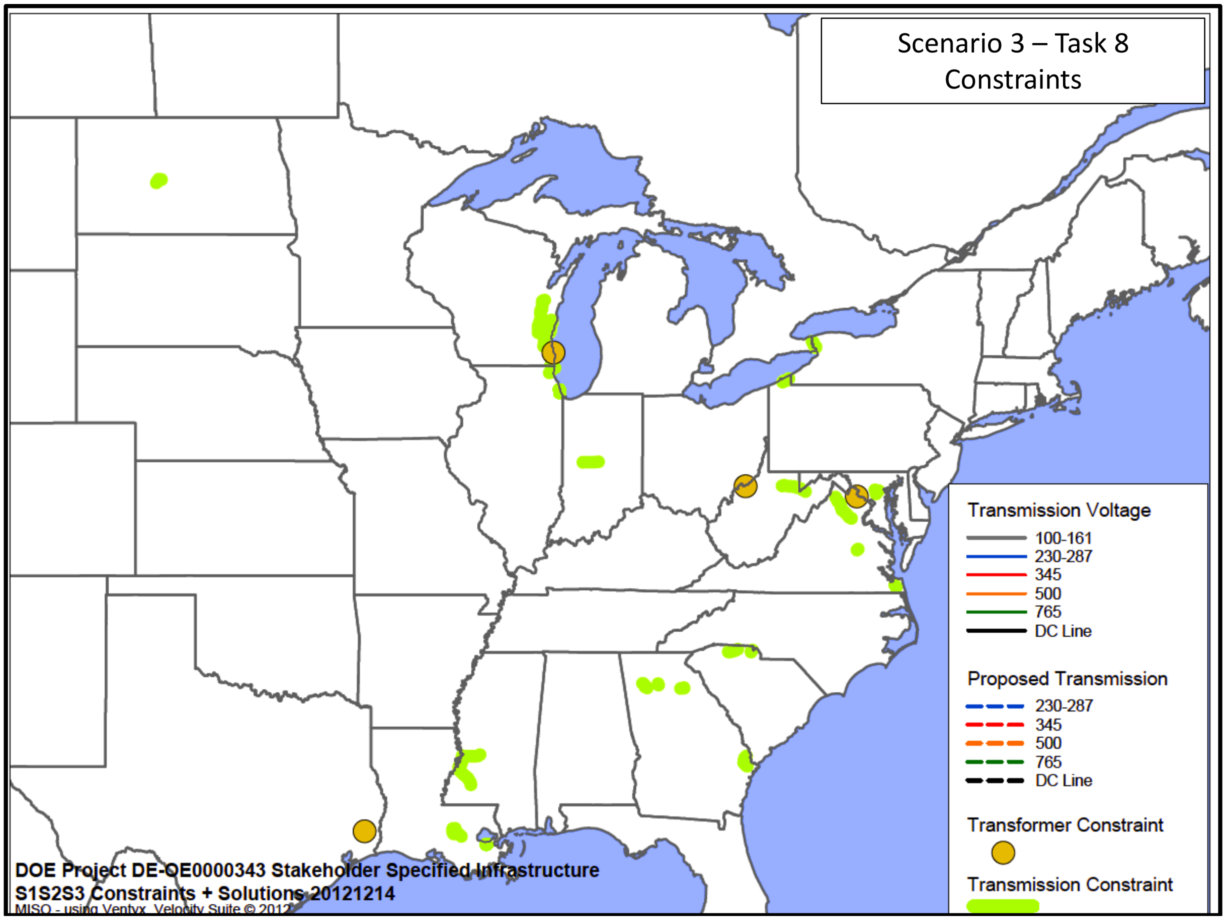


Figure 3-5. Scenario 3: BAU: Task 8 Constraints

Constraints show up in the MISO, Entergy and TVA regions and in the southeast. Scenario 3: BAU showed more constraints than Scenario 2: NRPS/IR in the Task 8 analysis, possibly because of the significant transmission already added in Scenario 2: NRPS/IR as a result of Task 7 analysis.

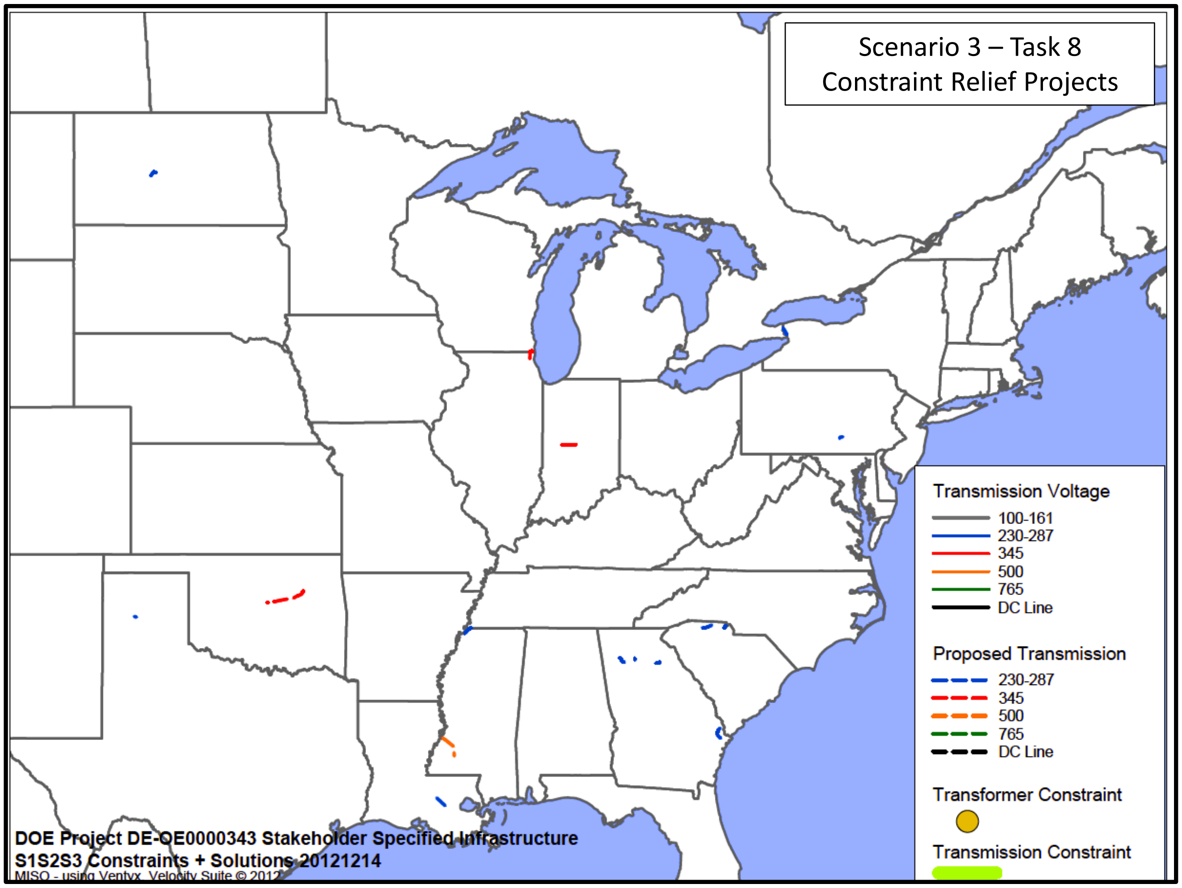


Figure 3-6. Scenario 3: BAU: Task 8 Transmission Additions

Figure 3-6 shows scattered transmission additions/enhancements that were needed for Scenario 3: BAU. Overall, 80 thermal constraint relief and 30 voltage support projects were needed to address transmission issues arising from Task 8 analysis. Most of these projects were upgraded or re-conductored lines. Both new lines and reconductored/upgraded lines are shown in Figure 3-5.

Overall, Task 8 provided additional reliability analysis for the three scenarios and resulted in some additional transmission being added, reconductored or upgraded. The amounts of transmission needed were significantly less than the transmission added for Task 7 analysis, generator interconnections, system intact overloads and voltage issues and N-1 system overloads and voltage issues. This is a typical result for planning efforts.

Table 3-1 summarizes the projects needed for each of the three scenarios.

Table 3-1. Number of Transmission Projects Needed by Type and Scenario

Transmission Projects	Scenario 1: CP – Combined Policy		Scenario 2: NRPS/IR – RI RPS		Scenario 3: BAU – BAU	
	Task 7	Task 8	Task 7	Task 8	Task 7	Task 8
Generator Interconnection	365		295		90	
Constraint Relief	415	85	215	65	200	80
HVDC	6					
Voltage Support		40		5		30

As can be seen, the differences occur in the generator interconnection and constraint relief projects for Task 7. Scenario 1: CP requires the most transmission additions, followed by Scenario 2: NRPS/IR and Scenario 3: BAU. The number of constraint relief and voltage support projects arising from the Task 8 analysis are relatively comparable for all three scenarios, with Scenario 2: NRPS/IR requiring fewer voltage support projects than Scenarios 1 and 3.

3.2 Task 8 - Identifying Flowgates

In Task 9, GE MAPS required a list of flowgates to monitor for each of the three scenarios while performing the production cost analysis. A flowgate is a single transmission element, or group of transmission elements, intended to model MW flow impacts relating to transmission limitations and transmission service usage. It is an element that responds to a power flow transfer with a Transfer Distribution Factor (TDF) of 5% or more while all elements are in service or under contingency. A TDF is defined as the percentage of the applied transfer flowing on an element. For example, if the applied transfer was 5000 MW's and an element had a TDF of 5%, the amount of power flowing on the element due to the applied transfer would be 250 MW's. A flowgate is made up of one or more monitored transmission facilities and optionally one or more contingency facilities. The maximum power flow capability on a flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.

Flowgates are identified for the flows going from one NEEM region to another. To determine the flowgates for GE MAPS, TARA by PowerGem was used to perform linear transfers on each scenario's power flow cases from each NEEM Region to its 1st Tier Neighboring NEEM Regions[3]. For each scenario the resulting list of inter-regional flowgates was reviewed by each PA. During this review, the PA's could remove invalid flowgates (ex. invalid contingency), duplicate flowgates (ex. series element) and add additional flowgates ("local" flowgate). The updated flowgate list was then provided to CRA for use in the GE MAPS production cost analysis.

Models such as GE MAPS cannot practically monitor all transmission elements; it is customary to configure GE MAPS to enforce only those transmission ratings (flowgates) that are material to the GE MAPS solution since doing so will dramatically reduce the amount of time it takes a computer to complete a simulation. The process described above was designed to identify the

[3] A 1st Tier Neighboring NEEM region is a region that is adjacent to the region under analysis. A 2nd Tier region would be a region that was adjacent to the 1st Tier region, *i.e.*, "two regions away."

material flowgates. If material flowgates were overlooked, the model would underestimate production costs. Scenario 1: CP had 1,134 identified flowgates, Scenario 2: NRPS/IR had 857 and Scenario 3: BAU had 935.

4 Base Scenarios: Production Cost Analysis and Cost Estimates

4.1 Objective of the Task

The purpose of Tasks 9 and 10 was to evaluate, to the extent possible, the costs and benefits associated with the three future scenarios selected in Phase 1. This involved using the GE MAPS production cost tool and developing some cost estimates exogenously.

Economic analysis was performed using the GE MAPS production cost modeling for each scenario based upon the power flow modeling and transmission expansion options developed in Tasks 7 and 8. Production cost analysis assessed all hours of a single future year (2030) and forecasted energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors.

The production cost analysis was performed for the three base scenarios and six sensitivities. Production and emissions costs were developed for the three base scenarios and the six sensitivities. Capital and "Other" cost estimates, however, were developed only for the three base scenarios. Key inputs for the production cost analysis included the input assumptions from Phase 1 and those developed by the Modeling Working Group, as well as the resource expansion facilities from the NEEM analysis in Task 5, the Eastern Interconnection power flow models from Task 7 and flowgates identified during Task 8 analysis.

4.2 Description of the Process

4.2.1 GE MAPS Model

CRA used the GE MAPS model to perform a production cost analysis of Scenarios 1: CP, 2: NRPS/IR, and 3: BAU along with the six additional sensitivities for the year 2030. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The model footprint comprises the entire Eastern Interconnection, and includes all of the generating units, the transmission additions, and the transmission load flow and flowgates that were identified in Tasks 7 and 8 for each scenario. The transmission system represented in each GE MAPS model was designed to accommodate the generation and interchanges during the peak and off-peak hours chosen for reliability modeling.

The NEEM analysis originally used by CRA for the macroeconomic analysis was a "pipes and bubbles" method of analyzing the generation resource mix and general location of generators for different energy policy futures. Combined with CRA's MRN model, it modeled effects on the entire economy along with the generation resources needed. The NEEM model is a more simplified model than GE-MAPS from a generation and transmission representation perspective. The NEEM model uses 20 load blocks versus 8,760 hours modeled by the GE-MAPS model for a given year. In addition, the NEEM model assumed no transmission constraints within NEEM regions and required transmission transfer capabilities as an input to the model whereas GE-MAPS represents the entire transmission system and models all constraints identified by the Planning Authorities (PAs).

The GE MAPS model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each flowgate monitored, and the locational marginal price (LMP) for each generator and load area.

In the GE MAPS modeling, there is a commitment (next-day) step and a dispatch (real-time) step. In the commitment process, generating units in a region are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load and required operating reserves in the region for the next day. GE MAPS then uses the set of committed units to dispatch the system on an hourly real-time basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs.

The modeled calendar year in Task 9 was 2030. The modeled geographic footprint in GE MAPS in Task 9 encompassed the U.S. portion of the Eastern Interconnection and the Canadian provinces of Ontario, Manitoba and Saskatchewan. The Eastern Interconnection interfaces with Hydro Quebec, WECC and ERCOT are represented using export/import border assumptions, as is the Maritimes portion of the Eastern Interconnection.

In Task 9, GE MAPS required a list of flowgates to monitor for each of the 3 scenarios while performing the production cost analysis. Flowgates were developed by the PAs; the approach is discussed in more detail in Section 3.2.

4.2.2 Inputs coming directly from NEEM

Below is a discussion of the inputs from NEEM. More detailed discussion and inputs can be found at http://www.eipconline.com/Resource_Library.html under the General Modeling Information and Resources section. Additional information can be found at http://www.eipconline.com/Phase_II_SSC_Meetings.html under the July 9, 2012 Webinar section.

4.2.2.1 Load

GE MAPS requires an hourly load profile and a forecast of peak load and total energy for every area ("MAPS Area") modeled. These MAPS Areas are typically individual control areas or utility service areas and collectively comprised the NEEM regions in the modeled footprint. Each MAPS Area was mapped to specific areas or buses defined in the power flow cases.

The load forecast for 2030 by NEEM region from Phase I was applied. The hourly load profiles, peak load and energy by NEEM region are used by GE MAPS to develop the load profile by MAPS Area for 2030. A 2006 load profile was used to develop the hourly load profile for all regions in the EI for this analysis; 2006 is considered to be a "normal weather" year. For the NEEM analysis the hourly loads were collapsed into blocks. For the GE MAPS analysis thee hourly load profiles are distributed among the load buses in each MAPS Area (from the power flow case) based on the load distribution defined in the power flow case.

In the power flow case, losses were assumed at a given level and the PAs did not change that level. The losses assumed in the power flow model are average losses. Production cost models use marginal losses to more accurately model the physical reality of power system losses.

Marginal losses are a measurement of the system transmission losses that would be incurred to supply an additional MW of energy to a given bus/location on the transmission system. The initial losses were taken from the power flow case, and then redistributed based on the dispatch.

4.2.2.2 Generating Capacity

Generating units in service for the year 2030 and the bus locations of the units are consistent with data included in the power flow cases for each of the three selected scenarios as derived using Phase 1 NEEM data. Each of the PAs determined where the generation deactivations and additions would be specifically located on their system; the one exception to this was individual units >200 MW which were deactivated in the NEEM analysis. The PAs utilized “brownfield” sites wherever possible for new units. If a plant was deactivated at a site and a new power plant was called for by NEEM, the PAs placed the new unit at the deactivated site. This reduced the need for new transmission for generation interconnections. In the case of wind, however, the vast majority of the generation additions had to be on “greenfield” sites, generally located where the wind availability was best. In Scenario 1: Combined Policies (CP), wind was located where the wind availability was best across the entire Eastern Interconnection (taking into account NEEM’s hurdle rates and wheeling charges) whereas in Scenario 2: National Renewable Portfolio Standard/ Implemented Regionally (NRPS/IR) wind was located where the wind availability was best within each region.

4.2.2.3 Thermal Unit Characteristics

Thermal generation modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology), summer and winter capacities, non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.

Capacity ratings, full load heat rates, forced outage rates, planned outage rates, and emission rates for existing units used in Phase 1 were used in GE MAPS. All units within a NEEM aggregate grouping have the same full load heat rates, forced outage rates, planned outage rates, non-fuel O&M cost, and emission rates. Post-retrofit emission rates and variable O&M costs for existing coal units are consistent with the NEEM results for each scenario for active units in 2030.

Heat rate steps implemented in GE MAPS as a function of full load heat rate (FLHR) are:

- CT: Single block at 100% capacity at 100% of FLHR.
- CC: 4 blocks: 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR.

As an example, for a 500 MW CC with a 7000 Btu/KWh FLHR, the minimum load block would be 250 MW at a heat rate of 7910, the 2nd step would be 85 MW at a heat rate of 5250, the 3rd step would be 80 MW at a heat rate of 6020, and the 4th step would be 85 MW at a heat rate of 7000.

- Coal less than 600 MW: 3 blocks: 50% capacity at 106% of FLHR, 75% capacity at 90% FLHR, and 100% capacity at 100% FLHR.
- Coal greater than 600 MW: 4 blocks: 30% capacity at 110% of FLHR, 50% capacity at 93% of FLHR, 75% capacity at 95% of FLHR and 100% capacity at 100% FLHR.
- Steam gas/oil less than 600 MW: 4 blocks: 30% capacity at 110% of FLHR, 50% capacity at 90% of FLHR, 75% capacity at 96% of FLHR and 100% capacity at 100% FLHR.
- Steam gas/oil greater than 600 MW: 4 blocks: 20% capacity at 110% of FLHR, 50% capacity at 95% of FLHR, 75% capacity at 98% of FLHR and 100% capacity at 100% FLHR.

Minimum up (min-up) and down times (min-down) implemented in GE MAPS are:

- CT: 1 hour for both min-up and min-down
- CC: 6 hours of min-up and 8 hours for min-down
- Coal: 24 hours for min-up and 12 hours for min-down. Sliding pressure super critical units, will have 16 hours min-up and 8 hours min-down.
- Steam gas/oil: 10 hours min-up and 8 hours min-down

Start-up costs including fuel and non-fuel components implemented in GE MAPS are:

- CT: No separate start-up cost.
- CC: $35/MW multiplied by the unit capacity per start up
- Coal: $45/MW multiplied by the unit capacity per start up
- Steam gas/oil: $40//MW multiplied by the unit capacity per start up.

Ramp rates and the ability to provide spinning reserves are discussed below.

4.2.2.4 Nuclear Units

Nuclear plants are assumed to run when available, and have minimum up and down times of one week. Capacity ratings and forced outage rates are the same as those used in NEEM in Phase 1. Planned outage rates are the same as those used in NEEM in Phase 1, and represent a normalized annual rate that does not directly capture the timing of refueling outages. In general, nuclear facilities are treated as must run units. Production costs will be modeled using Phase 1 NEEM input assumptions for fuel and variable O&M.

4.2.2.5 Hydro, Wind, and Other Renewable Resources

Hydro units are specified as a monthly pattern of water flow, *i.e.* the minimum and maximum generating capability and the total energy for each plant. Plant capacity and available energy are as used in NEEM in Phase 1. Pumped storage is assumed to have an efficiency of 75%.

Wind generation capacity factors in each NEEM region are consistent with Phase 1 input assumptions. The profile of hourly wind generation is similarly consistent with Phase 1 NEEM input data. In the GE MAPS run, wind generation is "curtailed" in an hour if the LMP at the bus at which the wind generator is located is below $1/MWh. The $1/MWh was chosen by the MWG to prevent additional generation from yielding negative revenues.

4.2.2.6 External Regional Supply

CRA explicitly models the U.S. portion of the Eastern Interconnect and the Canadian provinces of Ontario, Manitoba and Saskatchewan. The DC ties with the WECC and ERCOT interconnections were modeled using an hourly scheduled interchange derived from the Phase I NEEM runs for each scenario. Similarly, the Hydro Quebec and Maritimes interconnections within the modeled footprint are modeled using an hourly scheduled interchange derived from the Phase 1 NEEM runs for each scenario.

4.2.2.7 Seams Charges/Hurdle Rates

Seams charges are "per MWh" charges for moving energy from one control area to another in an electric system. In GE MAPS, seams charges are applied to net interregional power flows in each hour and also used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Seams charges are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch.

Dispatch seams charges or hurdles between regions are set to those applied in NEEM in Phase I. For the HVDC lines, there are no seams charges within MISO (*i.e.*, between the NEEM regions in MISO), so HVDC lines that start and end in MISO bubbles do not have seams charges. For the MISO-PJM DC lines in Scenario 1: CP, the same $2/MWh seams charge applied on the AC lines between MISO and PJM is applied to these DC lines. For the SPP-PJM DC lines in Scenario 1: CP, the same seams charge on other AC lines out of SPP ($5/MWh) is applied from SPP to PJM, and the same seams charge from PJM to TVA and VACAR ($6/MWh) is applied from PJM to SPP.

Unit commitment in GE MAPS is applied by 10 major commitment pools in the modeled footprint (FRCC, MISO, ISO-NE, NYISO, Ontario, PJM, SOCO, SPP/Entergy/AECI, TVA, and VACAR), meaning that resources are committed to meet commitment pool load based on the resources available in that pool. As such, commitment hurdles are not applicable between commitment pools. The commitment pools are generally set-up to cover reserve sharing areas (further described in the "Operating Reserves" section below).

NEEM regions MAPP_US and MAPP_CA are included in the MISO commitment pool. Inside this pool, a $10/MWh commitment hurdle is applied between MAPP_US and MISO/MAPP_CA (consistent with the existence of a dispatch hurdle between MAPP_US and MISO/MAPP_CA in Phase 1). Similarly, NEEM region "Non-RTO Midwest" is included in the TVA commitment pool, with a $10/MWh commitment hurdle applied between Non-RTO Midwest and TVA, and NEEM regions "ENT" and AECI are included in the SPP/Entergy/AECI commitment pool, with a $10/MWh commitment hurdle applied between ENT, AECI and SPP.

To incorporate the impact of the new DC lines in Scenario 1: CP that cross from one of the 10 commitment pools to another, a minimum and maximum MW amount of exports/imports collectively across the DC line(s) from/to each commitment pool were specified to be incorporated in the GE MAPS commitment process.

4.2.2.8 Operating Reserves

Operating reserves (spinning and standby) were based on requirements instituted by each reliability region. These requirements were based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves requirement affects energy prices, since that portion of a unit's capacity that is reserved for spin cannot produce electricity under normal conditions. Spinning reserves are modeled directly in GE MAPS. Table 4-1 below shows the spinning reserve requirements and the corresponding NEEM regions.

Table 4-1. Spinning Reserve Requirements

MAPS Commitment Pool	MAPS Operating Reserve Group	Spinning Reserve Requirement
ISONE	ISO-NE	530 MW
NYISO	Long Island	0 MW for NYISO-K (Long Island)
NYISO	East NY	300 MW for NYISO-G ~ NYISO-K
NYISO	NYISO	600 MW for NYISO-A ~ NYISO-K
PJM	PJM Mid Atlantic	1150 MW + 7.5% of load
PJM	PJM RTO	1509 MW + 7.5% of load
Midwest	MISO	800 MW
TVA	TVA	625 MW
SPP	SPP	983 MW
VACAR	VACAR	2% of hourly load
SOCO	SOCO	3% of hourly load
FRCC	FRCC	350 MW
IESO	IESO	225 MW

In modeling supply resources for operating reserves, the spinning and quick start capabilities of generating units were specified on a unit type basis. For spinning reserves, the maximum level of spinning reserve capability of a thermal unit was set as the lesser of the unit's capacity above minimum block and the unit's ramp rate (in MW/min) times 10, as spin requirements are typically needed within 10 minutes. Assumed ramp rates were: 10 MW/min for combined cycle units, 6 MW/min for gas and oil steam units, 3 MW/min for coal units. All ramp rates were limited to no more than 50% of a unit's capacity.

For hydro plants, spinning reserve capability was set on a monthly basis at 50% of the difference between the plant's capacity in that month and its average for that month's hourly output. No spinning capability is assigned to nuclear units, wind units, or other non-hydro renewables.

4.2.2.9 Fuel and Emission Prices

The GE-MAPS model uses a monthly fuel price for each thermal unit.

The natural gas fuel prices by NEEM region used in Phase 1 by season (winter, summer, shoulder) were applied. Winter prices apply for December through February. Summer prices apply for May through September. Shoulder prices apply in all other months.

The annual distillate oil price used in NEEM in Phase 1 were used and assumed to remain constant over the year. Coal prices are taken from the NEEM results in Phase 1.

Emission allowance prices for NO_x and SO_2 were taken from the NEEM results in Phase 1 for each selected scenario. If applicable for the selected scenario, annual CO_2 emission prices from Phase 1 were applied.

4.2.2.10 Hourly Wind Generation Profile

The hourly wind generation profile chosen was 2006. This was chosen to match with the load profile. The year 2006 is considered to be a very "normal" weather year in terms of energy use; that is the weather was neither warmer nor colder than normal temperatures. The wind profile for 2006 does have some anomalies when compared to a "normal wind" year but was chosen to coincide with the load profile.

4.2.3 Inputs Developed by PAs/Stakeholders

4.2.3.1 Transmission

The Task 9 GE MAPS transmission representation is based on three separate power flow cases provided by EIPC as part of Tasks 7 and 8. The power flow cases encompass the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties.

The PAs chose the flowgates to be monitored by GE MAPS (discussed above). All flowgates provided by EIPC were explicitly monitored.

4.2.3.2 Demand Response Variable Cost

Phase I values for the demand response (DR) reductions in peak loads were applied. The DR was spread among MAPS Areas based on the MAPS Area's share of the total NEEM region load. Within each MAPS Area the DR was proportioned among the load buses based on the load levels from the power flow case. Consistent with Phase 1, the DR was implemented as "pseudo-generators" with an average dispatch price of $750/MWh. This value was chosen using a Federal Energy Regulatory Commission-developed National Assessment of Demand Response (NADR). However, unlike the static $750/MWh dispatch price utilized in Phase 1, at the request of stakeholders, a step function was developed that would dispatch some DR at costs lower than $750 and some at prices higher with the average remaining at $750/MWh to be consistent with Phase 1 assumptions. The step function, shown in Figure 4-1s was designed to test the impact of DR at lower prices.

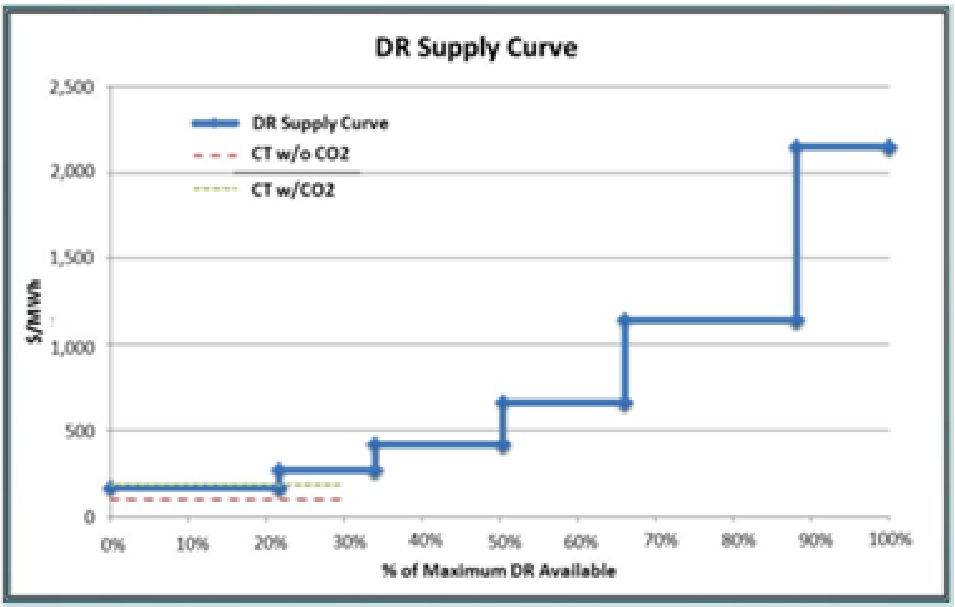


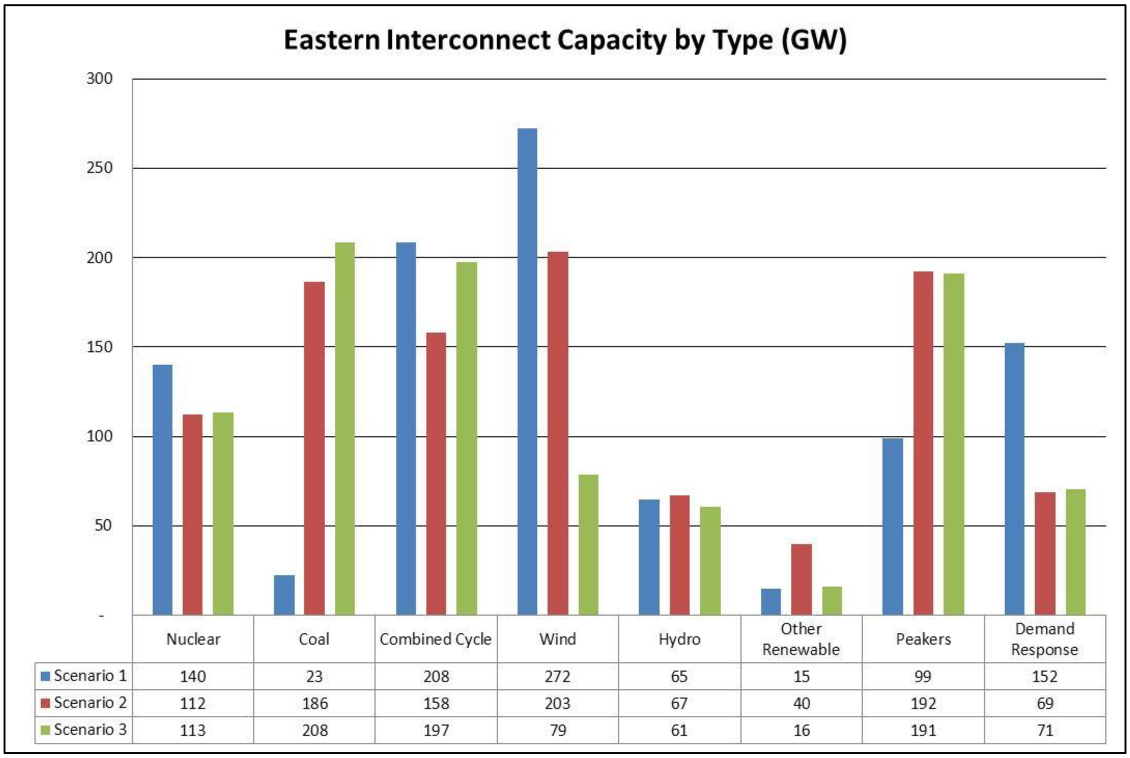
Figure 4-1. DR Supply Curve

4.2.4 <u>Production Cost Results: Output Reports for Base Scenarios</u>

CRA output reports were formulated to include:

- Annual 2030 data by EI NEEM region
    - Generation output, emissions, fuel costs, variable O&M costs, and emission costs by generating type
    - DR use by NEEM region and wind curtailment
    - Flow on DC lines and tie-lines
    - Flowgate congestion
- Hourly 2030 data
    - Loads and Load LMPs
    - Flow on DC lines and tie-lines between NEEM regions
    - Generation by type by NEEM region
    - Flowgate congestion

Generation capacity and generation, production costs (fuel + variable O&M costs) emissions, and emission costs by generating type for the entire Eastern Interconnection in 2030 is shown below for the Base modeling runs for all three scenarios. Overall results with respect to such factors are generally consistent with the Phase 1 results, though significant wind curtailment levels in Scenario 1: CP led to a reduced share of wind output and an increased share of gas-fired generation output relative to the results seen in F8S7, the NEEM run used as the basis for Scenario 1: CP.



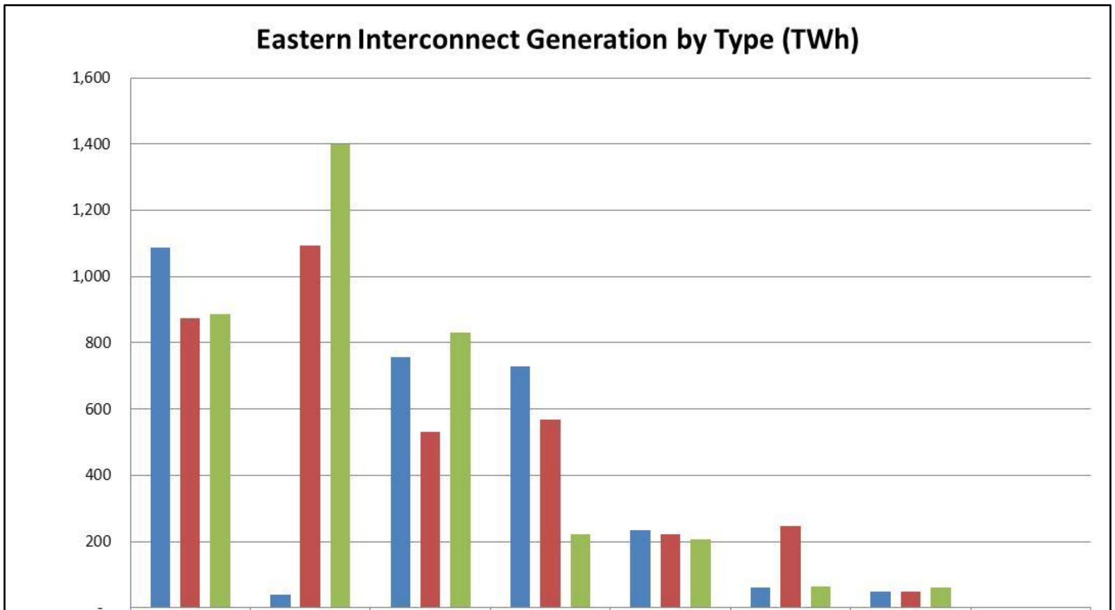
	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	140	23	208	272	65	15	99	152
Scenario 2	112	186	158	203	67	40	192	69
Scenario 3	113	208	197	79	61	16	191	71

Figure 4-2. EI Capacity by Type

The generating capacities for each scenario are designed to meet their differing load and energy requirements.

For Scenario 1: CP: Combined Policy, the largest amount of installed capacity in the Eastern Interconnection is wind capacity, followed by combined cycle and demand response. Together, these three generation types comprise 65% of the total capacity in the Eastern Interconnection. In Scenario 2: NRPS/IR: RPS Implemented Regionally, the largest amount of installed capacity in the Eastern Interconnection is wind capacity, followed by peakers and coal. Together, these three generation types comprise 57% of the total capacity in the Eastern Interconnection. In Scenario 3: Business as Usual (BAU): Business as Usual, the largest amount of installed capacity in the Eastern Interconnection is coal, followed by combined cycle and peakers. Together, these three generation types comprise 64% of the total capacity in the Eastern Interconnection.

Scenario 3: BAU, Business As Usual, models a capacity mix that is similar to what exists today with projected additions to meet a forecast of 2030 load levels. Scenario 2: NRPS/IR, which evaluates the implementation of a regional RPS program, contains a higher amount of renewable energy capacity with decreases in coal and combined cycle units. Scenario 1: CP, simulating a combined policy environment, has a large decrease in coal capacity, due to emissions constraints, which is largely replaced with wind and nuclear capacity above and beyond the Scenario 3: BAU levels.



	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	1,087	40	755	728	235	61	50	4
Scenario 2	875	1,095	532	568	222	248	50	0
Scenario 3	886	1,399	831	223	205	63	60	1

Figure 4-3. EI Energy by Type

In Scenario 1: CP, while wind, combined cycle and demand response make up the largest amount of installed capacity, the largest amount of generation comes from nuclear power plants, combined cycle and wind. Together they produce 87% of the energy needed for the Eastern Interconnection. In Scenario 2: NRPS/IR, the largest amount of generation comes from coal plants, nuclear and wind. Together they produce 71% of the energy needed for the Eastern Interconnection. The largest amounts of Scenario 3: BAU generation come from coal plants, nuclear and combined cycle. Together they produce 85% of the energy needed for the Eastern Interconnection.

Scenario 3: BAU has a less balanced portfolio than Scenario 2: NRPS/IR, both in terms of capacity and energy. The energy produced by the top three generation types in Scenario 3: BAU is roughly equal to Scenario 1: CP with coal replacing wind in Scenario 3: BAU. Combined cycle and nuclear energy show up in the top three energy sources in Scenarios 1 and 3, producing 50% and 47% of total energy, respectively.

Production Costs, Emissions Costs, and Emissions for the EI in 2030 are shown below for the Base modeling runs for all three scenarios.

Table 4-2. Annual Costs, Emissions, Demand and Energy

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

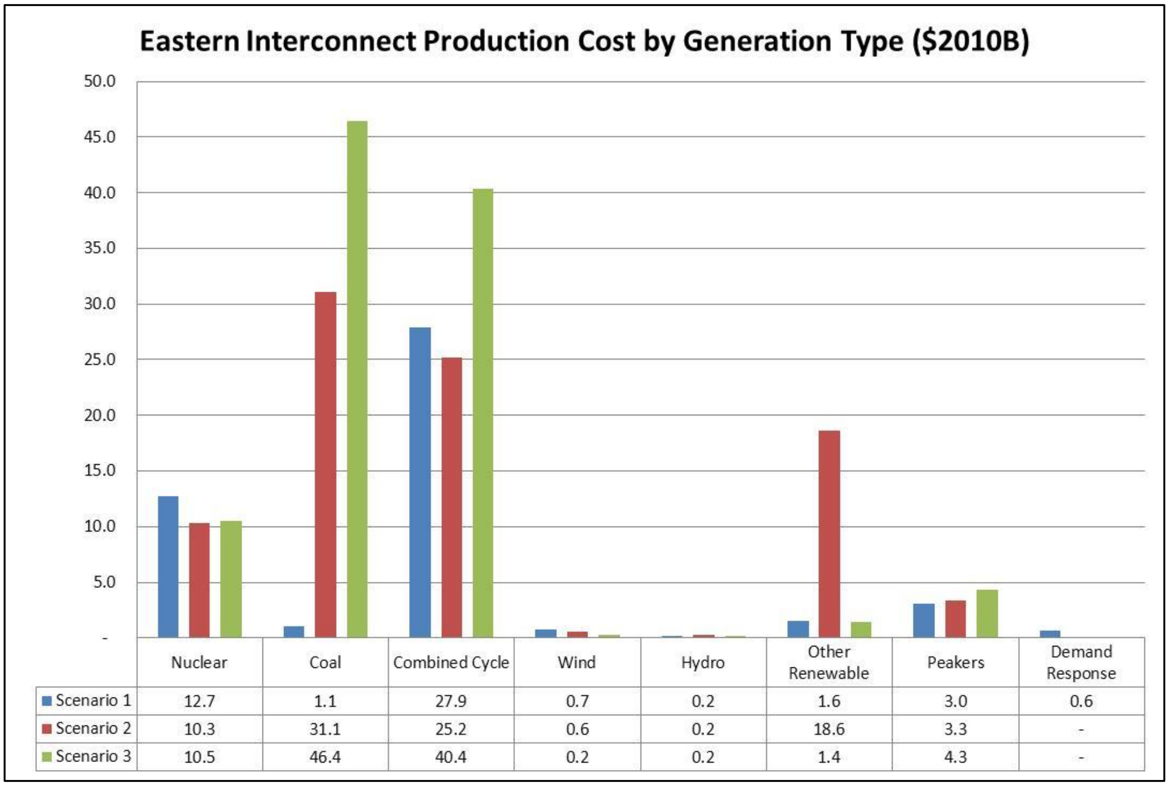
CO_2, SO_x and NO_x emissions in Scenario 1: CP are significantly lower than in Scenarios 2: NRPS/IR and 3: BAU, due to the policies that are being modeled. Production costs (fuel and variable O&M) are also significantly lower than in Scenarios 2: NRPS/IR and 3: BAU. In this scenario, EI-wide CO_2 costs are explicitly modeled based on an underlying CO_2 price determined in the Phase I NEEM runs and the quantity of emissions from fossil-fueled resources. Those costs are shown in the "Total w/ CO_2" entry in the table above. The peak demand and energy for Scenario 1: CP are lower than for Scenarios 2: NRPS/IR and 3: BAU because of the aggressive energy efficiency/demand response assumptions made in Scenario 1: CP.

Emissions in Scenario 2: NRPS/IR are significantly higher than in Scenario 1: CP, resulting from a generation portfolio that is more dependent on fossil fuel generation. Production costs are also significantly higher than Scenario 1: CP also due more reliance on fossil-fuel generation. EI-wide CO_2 costs were assumed at current levels, *i.e.*, only those costs incurred in Regional Greenhouse Gas Initiative (RGGI) states in Scenario 2: NRPS/IR. Thus the CO_2 costs shown in the summary above are small.

Emissions in Scenario 3: BAU are the highest of the three scenarios, with no additional environmental policies assumed other than implementation of the EPA regulations as they were proposed in 2011. There are significant CO_2 emissions but as with Scenario 2: NRPS/IR the CO_2 costs were assumed by the SSC to be at existing levels for RGGI states. The very low costs in Scenario 3: BAU resulted from these assumptions. Overall production costs for Scenario 3: BAU are the highest of the three scenarios, roughly $56 billion/year higher than Scenario 1: CP, and $14 billion/year higher than Scenario 2: NRPS/IR.

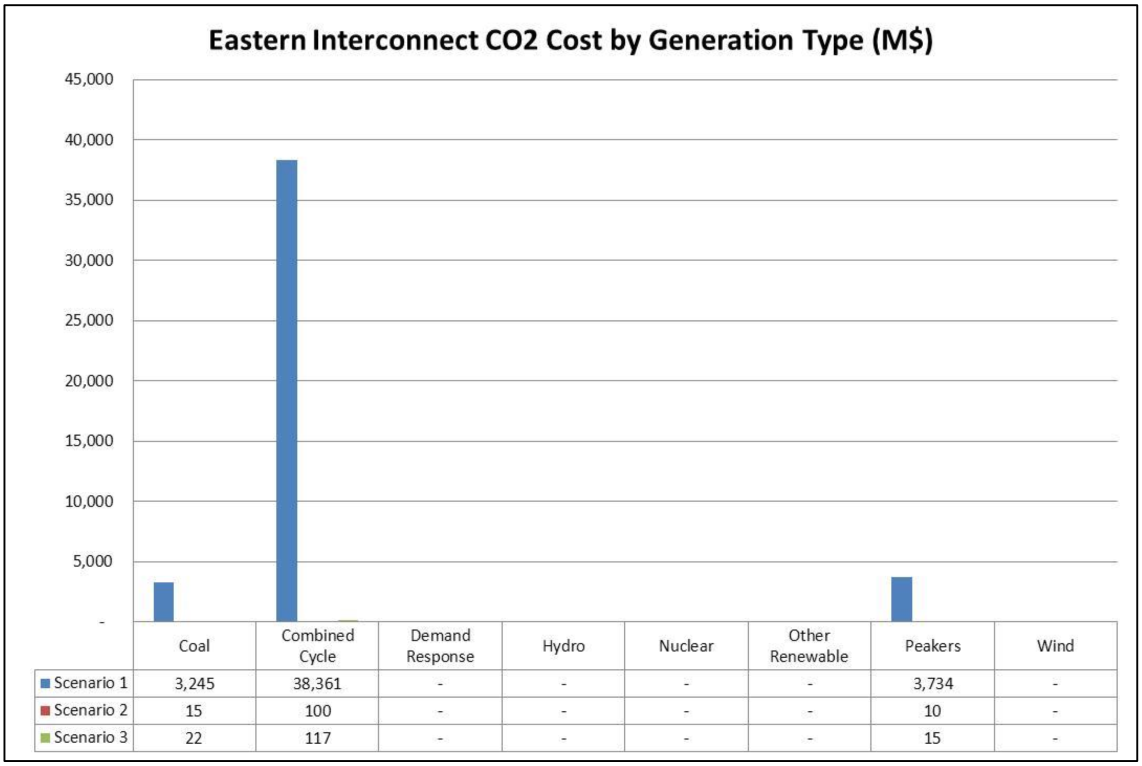
Including CO_2 costs in the total costs shows relatively small differences between three scenarios designed to be "bookend" scenarios. Scenario 3: BAU has approximately 15% higher costs than Scenario 2: NRPS/IR and approximately 11% higher costs than Scenario 1: CP with CO_2 costs included. Below is a chart summing the production and CO_2 costs and showing different types of emissions for each of the Base runs. Comparing fuel and variable O&M costs only shows that Scenario 1: CP costs are 53% of Scenario 2: NRPS/IR costs and 46% of Scenario 3: BAU costs.

Figures 4-4 and 4-5 present the production and CO_2 costs graphically by generation type.



	Nuclear	Coal	Combined Cycle	Wind	Hydro	Other Renewable	Peakers	Demand Response
Scenario 1	12.7	1.1	27.9	0.7	0.2	1.6	3.0	0.6
Scenario 2	10.3	31.1	25.2	0.6	0.2	18.6	3.3	-
Scenario 3	10.5	46.4	40.4	0.2	0.2	1.4	4.3	-

Figure 4-4. EI Production Cost by Generation Type



	Coal	Combined Cycle	Demand Response	Hydro	Nuclear	Other Renewable	Peakers	Wind
Scenario 1	3,245	38,361	-	-	-	-	3,734	-
Scenario 2	15	100	-	-	-	-	10	-
Scenario 3	22	117	-	-	-	-	15	-

Figure 4-5. CO_2 Costs by Generation Type

4.2.5 NEEM and GE MAPS Transfers

In Phase 1, the EIPC and SSC agreed upon an expansion of the transmission inter-regional capacity of 37 GW in Future 8 Sensitivity 7, which became Scenario 1: CP in Phase 2; the total capacity in Scenario 1: CP was meant to be 155 GW. For Scenario 3: BAU the SSC agreed upon no additional expansion of the transmission inter-regional capacity and the total capacity was meant to be 118 GW. During the Build-out task in Phase 2, both AC and DC lines were added to the grid in order to meet reliability constraints during one peak hour and one off-peak hour in 2030, while approximating the power generation, loads and interchange increases specified in Phase 1. The transmission system for the BAU case was similarly built-out for the peak hour in 2030.

The transmissions systems resulting from the reliability analysis were then modeled in GE MAPS for all 8760 hours. The results from the Phase 2 GE MAPS analysis show greater tieline flows between the regions in both scenarios than were seen or specified in the Phase 1 NEEM analysis. Inter-regional flows at the system peak for Scenario 1: CP in the GE MAPS analysis total 223 GW and for Scenario 3: BAU the inter-regional flows at system peak are 106 GW. Thus the peak flows for Scenario 1: CP are higher than Scenario 3: BAU by 117 GW rather than the 37 GW that was specified in Phase 1 of the project. Scenario 1: CP average flows over the 8760 hours total 84 GW and Scenario 3: BAU average flows total 26 GW. The average flows for Scenario 1: CP are 58 GW higher than those in Scenario 3: BAU, compared to the 37 GW of additional capacity that was specified in Phase 1.

There are several tables following that show the results from MAPS and from NEEM. Table 4-3 shows the peak flow (either direction) and the average flow for every tieline in both Scenario 1: CP and Scenario 3: BAU from GE MAPS. The table also does not show the capacities of the tielines because the MAPS output from CRA only shows the limits for flowgates, not the limits for tielines. Summing up the flowgate limits for each inter-region would provide very different results because of the way flowgates are defined.

Table 4-3. Tieline Peak and Average Flows from GE MAPS

Tieline	S1 Peak	S3 Peak	Difference	S1 Average	S3 Average	Difference
ENTERGY-MAPP_US	0.1	0.1	0.0	0.0	0.0	0.0
ENTERGY-MISO_MO_	3.5	1.8	1.6	0.4	0.6	(0.2)
ENTERGY-MISO_W	0.1	0.2	(0.0)	0.1	0.1	(0.0)
ENTERGY-NE	0.8	0.7	0.1	0.5	0.4	0.2
ENTERGY-SOCO	2.1	1.0	1.1	0.7	0.0	0.7
ENTERGY-SPP_N	2.6	1.6	1.0	1.1	0.5	0.6
ENTERGY-SPP_S	17.0	2.0	15.0	7.3	0.0	7.2
ENTERGY-TVA	7.4	4.4	3.0	1.8	0.5	1.3
FRCC -SOCO	4.3	4.5	(0.2)	0.2	0.9	(0.7)
IESO -MAPP_CA	0.4	0.5	(0.0)	0.3	0.1	0.2
IESO -MISO_MI	4.4	3.2	1.2	3.5	1.5	2.1
IESO -MISO_W	0.2	0.2	0.1	0.1	0.0	0.0
IESO -NYISO_A-	2.2	2.1	0.1	1.5	0.8	0.7
MAPP_CA-MAPP_US	1.5	0.8	0.7	0.0	0.2	(0.1)
MAPP_CA-MISO_W	2.5	2.0	0.5	1.8	0.8	1.1
MAPP_US-MISO_W	4.0	3.1	0.9	0.2	0.6	(0.5)
MAPP_US-NE	1.3	1.3	(0.1)	0.1	0.2	(0.1)
MISO_IN-MISO_MI	0.8	0.1	0.7	0.4	0.0	0.4
MISO_IN-MISO_MO_	1.8	0.6	1.2	0.3	0.3	0.0
MISO_IN-NON_RTO_	2.5	1.3	1.1	1.2	0.3	0.9
MISO_IN-PJM_REST	8.7	2.3	6.3	3.5	0.1	3.4
MISO_IN-TVA	0.6	0.5	0.1	0.0	0.0	(0.0)
MISO_MI-MISO_WUM	0.2	0.1	0.0	0.0	0.0	(0.0)
MISO_MI-PJM_REST	4.7	3.9	0.8	2.4	0.2	2.2
MISO_MO_-MISO_W	3.3	1.2	2.1	2.0	0.4	1.6
MISO_MO_-PJM_REST	4.3	2.5	1.8	1.2	0.1	1.1
MISO_MO_-SPP_N	1.0	0.8	0.3	0.6	0.4	0.2
MISO_MO_-SPP_S	0.2	0.1	0.1	0.1	0.0	0.1
MISO_MO_-TVA	2.2	1.1	1.1	0.7	0.3	0.4
MISO_W -MISO_WUM	3.8	1.7	2.1	1.5	0.4	1.1
MISO_W -NE	9.0	2.8	6.2	1.4	0.7	0.7
MISO_W -PJM_REST	3.1	2.1	1.1	0.5	0.4	0.1
MISO_W -SPP_N	2.1	0.1	2.0	0.4	0.0	0.4
MISO_WUM-PJM_REST	3.4	3.6	(0.2)	0.7	0.4	0.2
NE -SPP_N	12.6	2.9	9.6	3.0	1.5	1.5
NEISO -NYISO_A-	1.3	1.3	0.0	0.2	0.0	0.2
NEISO -NYISO_GH	1.3	1.2	0.1	0.2	0.2	0.0
NEISO -NYISO_J_	0.5	0.5	0.1	0.3	0.1	0.1
NON_RTO_-PJM_REST	3.1	3.7	(0.6)	2.0	0.9	1.0
NON_RTO_-TVA	1.7	1.0	0.8	0.2	0.1	0.1
NYISO_A-NYISO_GH	6.4	4.5	1.9	3.8	2.4	1.4
NYISO_A-PJM_R_MA	2.2	1.5	0.7	1.3	0.7	0.6
NYISO_GH-NYISO_J_	5.3	5.4	(0.2)	4.6	4.1	0.5
NYISO_GH-PJM_E_MA	1.9	0.8	1.1	0.0	0.0	0.0
NYISO_J_-PJM_E_MA	2.0	1.3	0.7	0.6	0.4	0.3
NYISO_J_-PJM_R_MA	-	0.7	(0.7)	-	0.0	(0.0)
PJM_E_MA-PJM_R_MA	6.6	6.4	0.3	2.1	1.1	1.1
PJM_R_MA-PJM_REST	11.6	7.8	3.8	1.4	1.3	0.1
PJM_REST-TVA	2.1	1.4	0.8	0.9	0.0	0.9
PJM_REST-VACAR	5.0	3.6	1.4	0.5	0.3	0.2
SOCO -TVA	6.1	2.7	3.4	1.9	0.6	1.3
SOCO -VACAR	3.2	1.9	1.3	0.2	0.1	0.2
SPP_N -SPP_S	21.5	3.4	18.2	7.9	1.2	6.7
TVA -VACAR	0.6	0.4	0.2	0.1	0.1	0.0
HVDC MISO_W-PJM_ROR	14.9	-	14.9	11.1	-	11.1
HVDC SPP_N-PJM_ROR	3.6	-	3.6	2.4	-	2.4
HVDC SPP_S-PJM_ROR	3.5	-	3.5	3.0	-	3.0
Total	223.3	106.4	116.8	84.3	26.2	58.1

Table 4-4 shows the results from NEEM, including the capacity limits, the peak flow over the 20 load blocks it uses and the average flow over the year. The list is in the same order as those lines from MAPS. Note that there are a number of tielines missing in the NEEM results that are in MAPS. The capacity increase between F8S7 and F1S17 is 36.8 GW, what is referenced in the Phase 1 documentation However, the increase in peak flow is 56 GW and average flow is 54 GW, showing that the grid is more heavily used in the high wind case F8S7.

Table 4-4. Tieline Peak and Average Flows from NEEM

Tieline	F8S7 Cap	F1S17 Cap	Dif.	F8S7 Peak	F1S17 Peak	Diff	F8S7 Avg.	F1S17 Avg.	Diff
ENTERGY -MAPP US									
ENTERGY -MISO_MO_	2.5	2.5	0.0	2.5	2.5	0.0	0.3	0.3	0.0
ENTERGY -MISO_W									
ENTERGY -NE									
ENTERGY -SOCO	2.4	2.4	0.0	2.0	1.9	0.1	1.0	0.1	0.9
ENTERGY -SPP N	7.3	1.8	5.5	7.3	0.0	7.3	6.1	0.0	6.1
ENTERGY -SPP_S	4.7	1.3	3.4	4.3	0.9	3.4	2.9	0.0	2.9
ENTERGY -TVA	3.5	3.5	0.0	2.1	0.2	1.9	0.0	0.0	0.0
FRCC -SOCO	3.7	3.7	0.0	0.9	1.4	-0.5	0.0	0.1	0.0
IESO -MAPP_CA	0.3	0.3	0.0	0.3	0.3	0.1	0.1	0.2	-0.1
IESO -MISO MI	3.1	1.8	1.3	3.1	1.8	1.3	3.1	0.6	2.6
IESO -MISO_W	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.0
IESO -NYISO_A-	2.2	1.7	0.5	2.2	1.7	0.5	2.1	0.8	1.3
MAPP CA -MAPP US	0.4	0.4	0.0	0.4	0.4	0.0	0.1	0.0	0.1
MAPP_CA -MISO_W	2.0	2.0	0.0	2.0	2.0	0.0	1.2	0.1	1.1
MAPP US -MISO W	2.6	2.6	0.0	2.6	0.9	1.8	2.1	0.0	2.1
MAPP_US -NE	2.0	2.0	0.0	1.1	1.9	-0.9	0.2	0.4	-0.2
MISO_IN -MISO_MI	5.5	5.0	0.5	2.5	4.1	-1.6	0.9	1.9	-1.0
MISO IN -MISO MO	5.0	5.0	0.0	2.1	2.7	-0.6	1.4	0.7	0.7
MISO_IN -NON_RTO_	4.8	4.8	0.0	4.5	2.3	2.2	1.1	0.1	1.0
MISO IN -PJM REST	1.0	1.0	0.0	1.0	1.0	0.0	0.1	0.1	0.0
MISO_IN -TVA									
MISO_MI -MISO_WUM	0.3	0.1	0.2	0.3	0.1	0.2	0.0	0.1	-0.1
MISO MI -PJM REST	1.4	1.4	0.0	1.4	1.4	0.0	0.4	0.0	0.4
MISO_MO_-MISO_W	4.0	3.8	0.2	4.0	1.9	2.2	3.8	0.0	3.8
MISO MO -PJM REST	1.2	1.2	0.0	1.2	1.2	0.0	0.6	0.1	0.5
MISO_MO_-SPP_N	4.0	2.0	2.0	4.0	2.0	2.0	1.6	0.1	1.6
MISO_MO_-SPP_S									
MISO MO -TVA	4.1	4.1	0.0	4.0	1.3	2.7	1.8	0.0	1.8
MISO_W -MISO_WUM	1.7	1.6	0.1	1.7	1.5	0.3	1.3	0.3	1.0
MISO W -NE	4.8	2.8	2.0	3.6	0.0	3.6	2.4	0.0	2.4
MISO_W -PJM_REST	19.8	0.8	19.1	19.8	0.8	19.1	18.1	0.0	18.0
MISO_W -SPP_N	3.5	3.2	0.3	3.5	2.0	1.4	0.3	0.1	0.2
MISO WUM-PJM REST	1.6	1.6	0.0	1.6	1.6	0.0	0.3	0.6	-0.2
NE -SPP_N	1.9	1.8	0.1	1.9	1.8	0.1	1.1	1.0	0.1
NEISO -NYISO A-	0.6	0.6	0.0	0.6	0.6	0.0	0.1	0.4	-0.3
NEISO -NYISO_GH	0.6	0.6	0.0	0.6	0.6	0.0	0.3	0.5	-0.2
NEISO -NYISO_J_	1.0	0.4	0.6	1.0	0.4	0.6	0.7	0.4	0.3
NON RTO -PJM REST									
NON_RTO_-TVA	2.4	2.4	0.0	1.5	0.5	1.0	0.0	0.1	-0.1
NYISO A-NYISO GH	5.3	4.3	1.0	5.3	4.3	1.0	5.1	2.9	2.2
NYISO_A-PJM_R_MA	2.0	2.0	0.0	1.0	2.0	-1.0	0.7	0.2	0.6
NYISO_GH-NYISO_J_	6.1	6.1	0.0	6.1	6.1	0.0	5.5	5.0	0.4
NYISO GH-PJM E MA	1.5	1.5	0.0	1.5	1.5	0.0	0.1	0.0	0.1
NYISO_J_-PJM_E_MA	0.3	0.3	0.0	0.3	0.3	0.0	0.0	0.1	-0.1
NYISO J -PJM R MA									
PJM_E_MA-PJM_R_MA	8.0	8.0	0.0	6.0	4.7	1.3	0.4	1.7	-1.3
PJM_R_MA-PJM_REST	8.0	8.0	0.0	8.0	6.8	1.2	5.7	3.1	2.6
PJM REST-TVA	2.5	2.5	0.0	2.5	1.2	1.3	0.9	0.0	0.9
PJM_REST-VACAR	3.0	3.0	0.0	3.0	3.0	0.0	1.8	0.9	1.0
SOCO -TVA	3.7	3.7	0.0	3.7	0.5	3.2	0.0	0.0	0.0
SOCO -VACAR	3.0	3.0	0.0	3.0	2.5	0.5	0.6	0.2	0.4
SPP_N -SPP_S	4.0	4.0	0.0	4.0	4.0	0.0	2.0	1.4	0.5
TVA -VACAR	1.1	1.1	0.0	1.1	0.7	0.4	0.0	0.0	0.0
HVDC MISO_W -PJM_ROR									
HVDC SPP N -PJM ROR									
HVDC SPP_S -PJM_ROR									
Total	154.8	117.9	36.8	137.5	81.3	56.1	78.7	24.7	54.1

Lastly, Table 4-5 compares the peak flow for the two cases from Phase 1 and Phase 2. The MAPS results show a much larger amount of peak flow, even in the BAU case. In the high wind case, the Scenario 1: CP has a total of 223 GW transfer while the F8S7 only had 137 GW. In fact, the F8S7 case had a maximum capacity of only 155 GW. The build-out (from Phase 2 used in GE MAPS) ended up requiring more transmission capacity (than shown in Phase 1 by NEEM) to meet reliability constraints and GE MAPS used that capacity to the maximum extent possible.

Table 4-5. Tieline Peak Flows from MAPS and NEEM

Tieline	S1 Peak	S3 Peak	Difference	F8S7 Peak	F1S17 Peak	Difference
ENTERGY -MAPP_US	0.1	0.1	0.0			
ENTERGY -MISO_MO_	3.5	1.8	1.6	2.5	2.5	0.0
ENTERGY -MISO W	0.1	0.2	(0.0)			
ENTERGY -NE	0.8	0.7	0.1			
ENTERGY -SOCO	2.1	1.0	1.1	2.0	1.9	0.1
ENTERGY -SPP_N	2.6	1.6	1.0	7.3	0.0	7.3
ENTERGY -SPP_S	17.0	2.0	15.0	4.3	0.9	3.4
ENTERGY -TVA	7.4	4.4	3.0	2.1	0.2	1.9
FRCC -SOCO	4.3	4.5	(0.2)	0.9	1.4	-0.5
IESO -MAPP CA	0.4	0.5	(0.0)	0.3	0.3	0.1
IESO -MISO_MI	4.4	3.2	1.2	3.1	1.8	1.3
IESO -MISO_W	0.2	0.2	0.1	0.2	0.1	0.1
IESO -NYISO A-	2.2	2.1	0.1	2.2	1.7	0.5
MAPP_CA -MAPP_US	1.5	0.8	0.7	0.4	0.4	0.0
MAPP CA -MISO W	2.5	2.0	0.5	2.0	2.0	0.0
MAPP_US -MISO_W	4.0	3.1	0.9	2.6	0.9	1.8
MAPP_US -NE	1.3	1.3	(0.1)	1.1	1.9	-0.9
MISO IN -MISO MI	0.8	0.1	0.7	2.5	4.1	-1.6
MISO_IN -MISO_MO_	1.8	0.6	1.2	2.1	2.7	-0.6
MISO IN -NON RTO	2.5	1.3	1.1	4.5	2.3	2.2
MISO_IN -PJM_REST	8.7	2.3	6.3	1.0	1.0	0.0
MISO_IN -TVA	0.6	0.5	0.1			
MISO MI -MISO WUM	0.2	0.1	0.0	0.3	0.1	0.2
MISO_MI -PJM_REST	4.7	3.9	0.8	1.4	1.4	0.0
MISO MO -MISO W	3.3	1.2	2.1	4.0	1.9	2.2
MISO_MO_-PJM_REST	4.3	2.5	1.8	1.2	1.2	0.0
MISO_MO_-SPP_N	1.0	0.8	0.3	4.0	2.0	2.0
MISO MO -SPP S	0.2	0.1	0.1			
MISO_MO_-TVA	2.2	1.1	1.1	4.0	1.3	2.7
MISO W -MISO WUM	3.8	1.7	2.1	1.7	1.5	0.3
MISO_W -NE	9.0	2.8	6.2	3.6	0.0	3.6
MISO_W -PJM_REST	3.1	2.1	1.1	19.8	0.8	19.1
MISO W -SPP N	2.1	0.1	2.0	3.5	2.0	1.4
MISO_WUM-PJM_REST	3.4	3.6	(0.2)	1.6	1.6	0.0
NE -SPP N	12.6	2.9	9.6	1.9	1.8	0.1
NEISO -NYISO_A-	1.3	1.3	0.0	0.6	0.6	0.0
NEISO -NYISO_GH	1.3	1.2	0.1	0.6	0.6	0.0
NEISO -NYISO J	0.5	0.5	0.1	1.0	0.4	0.6
NON_RTO_-PJM_REST	3.1	3.7	(0.6)			
NON RTO -TVA	1.7	1.0	0.8	1.5	0.5	1.0
NYISO_A-NYISO_GH	6.4	4.5	1.9	5.3	4.3	1.0
NYISO_A-PJM_R_MA	2.2	1.5	0.7	1.0	2.0	-1.0
NYISO GH-NYISO J	5.3	5.4	(0.2)	6.1	6.1	0.0
NYISO_GH-PJM_E_MA	1.9	0.8	1.1	1.5	1.5	0.0
NYISO J -PJM E MA	2.0	1.3	0.7	0.3	0.3	0.0
NYISO_J_-PJM_R_MA	-	0.7	(0.7)			
PJM_E_MA-PJM_R_MA	6.6	6.4	0.3	6.0	4.7	1.3
PJM R MA-PJM REST	11.6	7.8	3.8	8.0	6.8	1.2
PJM_REST-TVA	2.1	1.4	0.8	2.5	1.2	1.3
PJM REST-VACAR	5.0	3.6	1.4	3.0	3.0	0.0
SOCO -TVA	6.1	2.7	3.4	3.7	0.5	3.2
SOCO -VACAR	3.2	1.9	1.3	3.0	2.5	0.5
SPP N -SPP S	21.5	3.4	18.2	4.0	4.0	0.0
TVA -VACAR	0.6	0.4	0.2	1.1	0.7	0.4
HVDC MISO W -PJM ROR	14.9	-	14.9			
HVDC SPP_N -PJM_ROR	3.6	-	3.6			
HVDC SPP_S -PJM_ROR	3.5	-	3.5			
Total	223.3	106.4	116.8	137.5	81.3	56.1

4.2.6 Wind Curtailment and Wind Production

The table below shows wind curtailment results from each of the three Scenario Base runs.

Table 4-6. Wind Curtailment

	S1 Base	S2 Base	S3 Base
Wind Curtailment (TWh)	131	30	1
Percent Curtailed	15%	5%	0%

Wind curtailment results from the Scenario 1: CP: Combined Policy Base model were substantial and were a significant concern to some stakeholders, who expected some level of wind curtailment in an hourly security-constrained economic dispatch but not the substantial levels seen.

The effect of the curtailment was to significantly lower average annual capacity factors on aggregate wind production in key high-wind regions of the Eastern Interconnection. The highest absolute amount of wind curtailments by NEEM region in the Scenario1: CP Base modeling run occurred predominately in three regions, MISO_West, Nebraska and SPP_North, all of which are generating wind in excess of the total demand in their region. For example, the "MISO W region contained potential wind resources at a 38% annual capacity factor (CF) Reductions due to curtailment in the base Scenario 1: CP model run lower this to 28.5%. Four other regions exhibiting any material level of wind curtailment are MAPP_US, SPP_South, MISO_MO/IL and IESO. As shown in Table 4-4, both the MAPP_US and SPP_South regions are over 90% of wind generated as a percent of their demand but the MISO_MO/IL and IESO regions have very similar absolute amounts of curtailment even though their wind generation as a percent of demand is only 26% and 12%, respectively.

Table 4-7. Wind Curtailments by NEEM Region (TWhs)

	Potential Wind Energy	Generated Onshore Wind Energy	Generated Offshore Wind Energy	Curtail-ment	Wind Generated as % of Demand	Curtail-ment Percent
ENT	1	1	0	0	0%	30%
FRCC	0	0	0	0	0%	
MAPP_US	32	28	0	4	97%	12%
MISO_IN	28	28	0	1	32%	2%
MISO_MI	24	24	0	0	27%	0%
MISO_MO-IL	32	23	0	8	25%	26%
MISO_W	261	196	0	65	150%	25%
MISO_WUMS	9	9	0	0	16%	1%
NE	55	33	0	22	109%	40%
NEISO	18	16	2	0	15%	2%
NonRTO_Midwest	0	0	0	0	0%	
NYISO_A-F	19	18	0	1	33%	5%
NYISO_G-I	1	1	0	0	4%	0%
NYISO_J-K	0	0	0	0	0%	
PJM_E	6	2	4	0	2%	1%
PJM_ROM	6	6	0	0	4%	0%
PJM_ROR	44	43	0	1	9%	1%
SOCO	0	0	0	0	0%	
SPP_N	146	125	0	21	163%	15%
SPP_S	148	143	0	5	92%	3%
TVA	0	0	0	0	0%	0%
VACAR	9	9	0	0	4%	0%
IESO	17	15	0	2	12%	13%
MAPP_CA	1	1	0	0	3%	0%
EI	859	722	6	131	24%	15%

As shown in Table 4-7, three of the richest wind regions in terms of both potential energy and performance (average capacity factor) – MISO West, Nebraska, and SPP North - saw curtailments of 25, 40, and 15 percent respectively from their benchmark levels (*i.e.*, expected capacity factor with no curtailment) in Scenario 1: CP. The curtailments dramatically lowered the achieved capacity factor for aggregate wind resources in those regions.

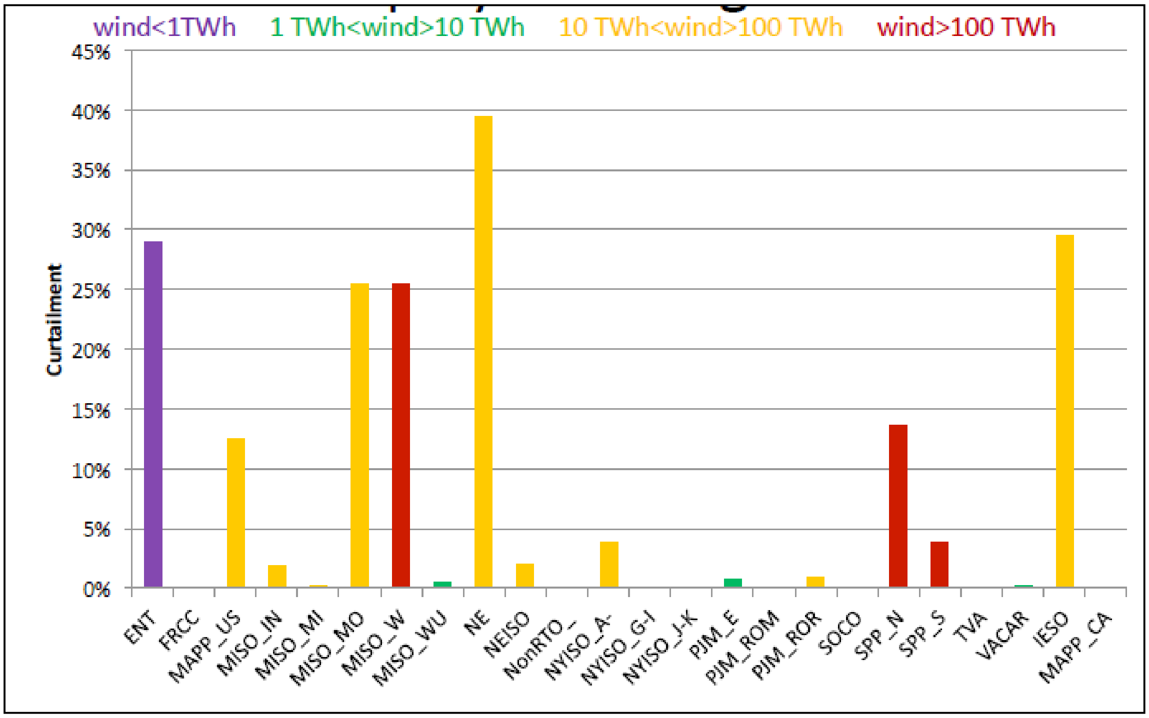


Figure 4-6. Curtailment in Low and High Wind Deployment Regions

Reviewing the information on a percentage basis yields additional insights. Figure 4-7 shows that the highest percent curtailment of wind does not necessarily occur in the regions with the greatest wind being produced. SPP_S with wind potential of 148 TWhs, has a very small percentage of curtailment while NE, with 55 TWhs of wind potential, had almost 40% of it curtailed.

Additional information regarding the cause of wind curtailment was evaluated in the sensitivity simulations, show in Section 6.0 of this report.

4.2.7 Regional Wind Production

While some stakeholders were concerned about the wind curtailment and how to increase wind production, other stakeholders were concerned about the lack of conventional baseload generation in areas with significant wind generation and the operational concerns that might result. Below is a graph of the daily generation dispatch for SPP South in Scenario 1: CP. This region has nearly 4,000 hours with no combined cycle, combustion turbines, coal or nuclear units on-line in the Scenario 1: CP base case. To accomplish this reliably would require a robust market with short trading intervals, additional VAr support and regulation, and modifications to base-load generation to enable it to cycle. Figure 4-8 shows the daily generation dispatch for Scenario 1: CP and the extensive amount of wind generation is evident.

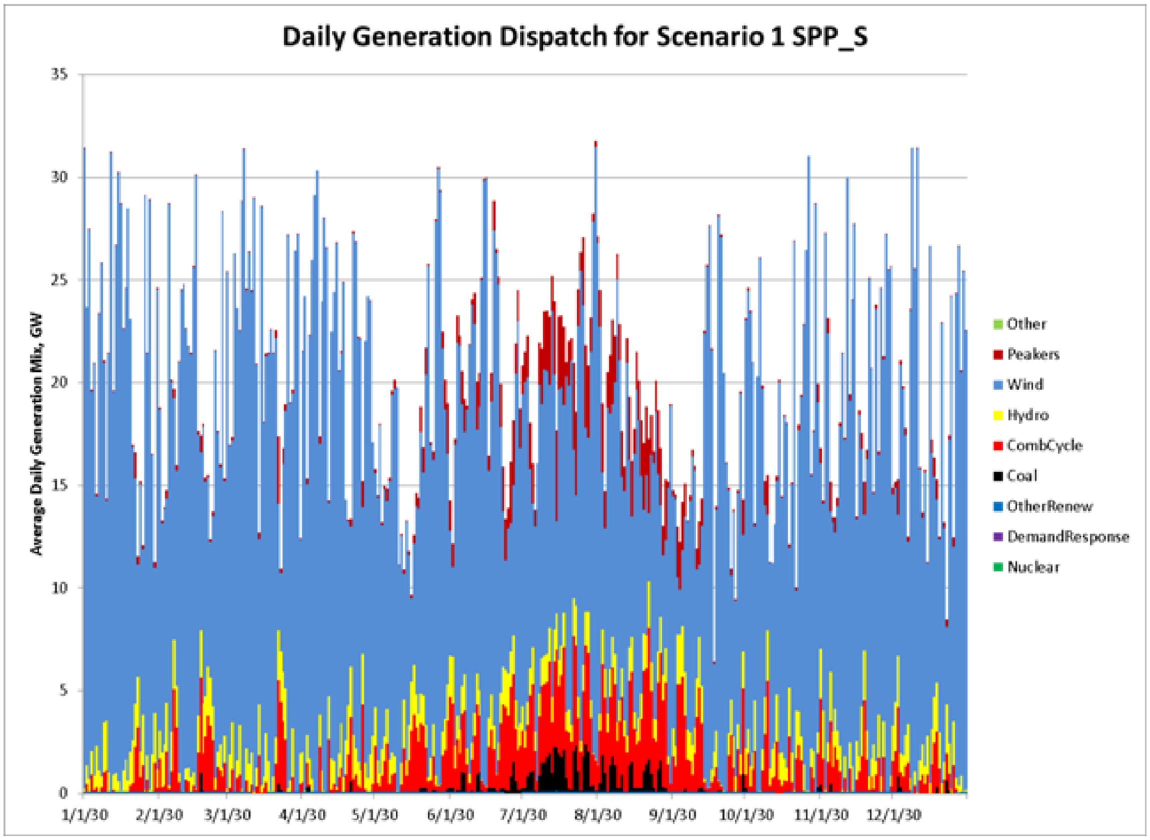


Figure 4-7. Daily Generation Dispatch for Scenario 1: CP

4.2.8 Demand Response

Another issue that became apparent through the Base run results and was a concern to some stakeholders was the dispersion and use of demand response in the Eastern Interconnection and the resulting high Locational Marginal Prices in those areas. The Scenario 1: CP, 2: NRPS/IR and 3: BAU Base Run results are presented below. However, modeling changes were made in the transmission topology in the sensitivity runs. Unfortunately, due to schedule constraints the Base runs could not be re-run and the model change was included in the sensitivity runs only. As can be seen from the information below, the DR utilized in the southeast is considerable.

Table 4-5 shows the DR usage by region. In the Scenario 1: CP Base modeling run, the vast majority of the demand response is utilized in the VACAR and SOCO regions. Together they comprise 75% of the total MWhs of demand response called for in the model and over 90% of the Demand Response MWh come from the top six regions in the table below. In terms of the hours that demand response is used, while all regions have at least one hour where DR is used, two regions – VACAR and MAPP_US – comprise 57% of the total hours. For the peak hour usage, three regions, VACAR, SOCO and PJM ROR, total over 57% of the peak DR usage; while nine regions did not utilize any DR at the time of the system peak.

Of the three scenarios, Scenario 1: CP calls for the highest use of DR, with approximately 14 times more DR than called for in Scenario 2: NRPS/IR on a MWh basis and more than 3.5 times the amount of DR called for in Scenario 3: BAU.

Table 4-8. Scenario 1: CP: Combined Policy - Demand Response

	S1 Base Demand Response			
NEEM Region	MWh	Maximum MW	MW at System Peak	# Hours**
VACAR	1,968,139	7,983	6,142	1,367
SOCO	674,892	4,473	4,129	376
FRCC	163,977	849	306	683
PJM ROR	147,133	5,829	4,627	92
MISO MO-IL	138,388	993	993	573
MAPP US	119,179	188	-	2,527
PJM ROM	69,292	2,471	1,916	84
NE	65,569	361	-	491
NEISO	41,137	2,985	2,097	26
MAPP CA	26,283	461	-	150
NYISO J-K	26,055	1,619	1,109	33
PJM E	25,386	1,961	1,720	34
NYISO A-F	19,173	1,021	670	43
MISO MI	15,828	1,356	865	22
MISO IN	13,866	901	831	27
NonRTO MW	7,243	508	508	27
NYISO G-I	5,695	403	278	29
ENT	5,488	598	-	69
MISO W	2,973	413	7	115
SPP N	2,487	817	-	5
SPP S	2,316	269	-	36
TVA	2,271	2,271	-	1
MISO WUMS	1,405	388	-	5
IESO	51	51	-	1
Total EI	3,544,226	33,782*	26,198	6,816

* Maximum MWs called in any single hour for EI - not the sum of Maximum regional MW

**Total EI hours is the sum of all hours in each region where DR was called.

In the Scenario 2: NRPS/IR Base modeling run, the vast majority of the demand response is utilized in the VACAR, SOCO and FRCC regions. Together they comprise 88% of the total MWhs of demand response called for in the model as shown in Table 4-6. In terms of the hours that demand response is used, SOCO, VACAR and FRCC account for 81% of the total DR hours. For the peak hour usage, three regions, VACAR, SOCO and PJM ROR, utilize 64% of the peak DR usage; thirteen regions are not utilizing any DR at the time of the system peak.

Table 4-9. Scenario 2: NRPS/IR: RPS Implemented Regionally – Demand Response

	S2 Base Demand Response			
NEEM Region	MWh	Maximum MW	MW at System Peak	# Hours**
SOCO	134,528	4,224	2,049	116
VACAR	62,302	2,322	1,936	110
FRCC	24,412	2,599	317	84
PJM ROR	6,798	1,954	1,954	6
NEISO	5,310	1,246	939	7
SPP S	4,080	675	-	9
PJM ROM	3,978	746	746	6
PJM E	2,629	534	534	6
NYISO J-K	2,194	368	368	6
SPP N	1,646	381	-	7
NYISO A-F	1,161	237	212	6
NE	1,124	211	-	8
NYISO G-I	544	91	91	6
MISO_MI	386	386	-	1
MISO_IN	153	89	63	2
MAPP CA	72	36	-	2
ENT	-	-	-	-
MAPP_US	-	-	-	-
MISO_MO-IL	-	-	-	-
MISO_W	-	-	-	-
MISO_ WUMS	-	-	-	-
NonRTO Midwest	-	-	-	-
TVA	-	-	-	-
IESO	-	-	-	-
Total EI	251,313	11,491*	9,209	382

* Maximum MWs called in any single hour for EI - not the sum of Maximum regional MW

**Total EI hours is the sum of all hours in each region where DR was called.

The Scenario 3: BAU Base modeling run had a total of 950,335 MWh with the vast majority of the demand response being utilized in the SOCO and VACAR regions. Together they comprise 84% of the total MWh of demand response called for in the model. Many regions have no demand response called on in this scenario. In terms of the hours that demand response is used, 63% of the hours are used in the same two regions: SOCO and VACAR. The vast majority of the regions have less than 1% of the hours utilizing DR. For the peak hour usage, VACAR and SOCO use 55% of the peak DR usage. Although the majority of regions are utilizing some amount of DR at the peak hour, nine regions have no DR use at all in this scenario.

Table 4-10. Scenario 3: BAU: Business as Usual - Demand Response

	S3 Base Demand Response			
NEEM Region	**MWh**	**Maximum MW**	**MW at System Peak**	**# Hours****
SOCO	583,316	5,453	4,363	340
VACAR	214,987	2,285	2,250	317
SPP S	81,279	1,025	484	206
FRCC	48,175	1,413	868	111
PJM ROR	5,352	1,043	757	9
PJM ROM	4,941	762	762	7
NEISO	4,662	919	919	7
NYISO J-K	2,371	394	394	7
PJM E	1,873	541	541	7
MISO MI	1,180	671	221	3
NYISO A-F	747	250	238	7
MAPP CA	732	112	-	10
NYISO G-I	548	99	99	7
MISO IN	90	52	38	2
ENT	83	9	-	9
MAPP US	-	-	-	-
MISO MO-IL	-	-	-	-
MISO W	-	-	-	-
MISO WUMS	-	-	-	-
NE	-	-	-	-
NonRTO MW	-	-	-	-
SPP N	-	-	-	-
TVA	-	-	-	-
IESO	-	-	-	-
Total EI	950,335	13939*	11,934	1,049
* Maximum MWs called in any single hour for EI - not the sum of Maximum regional MW				
**Total EI hours is the sum of all hours in each region where DR was called.				

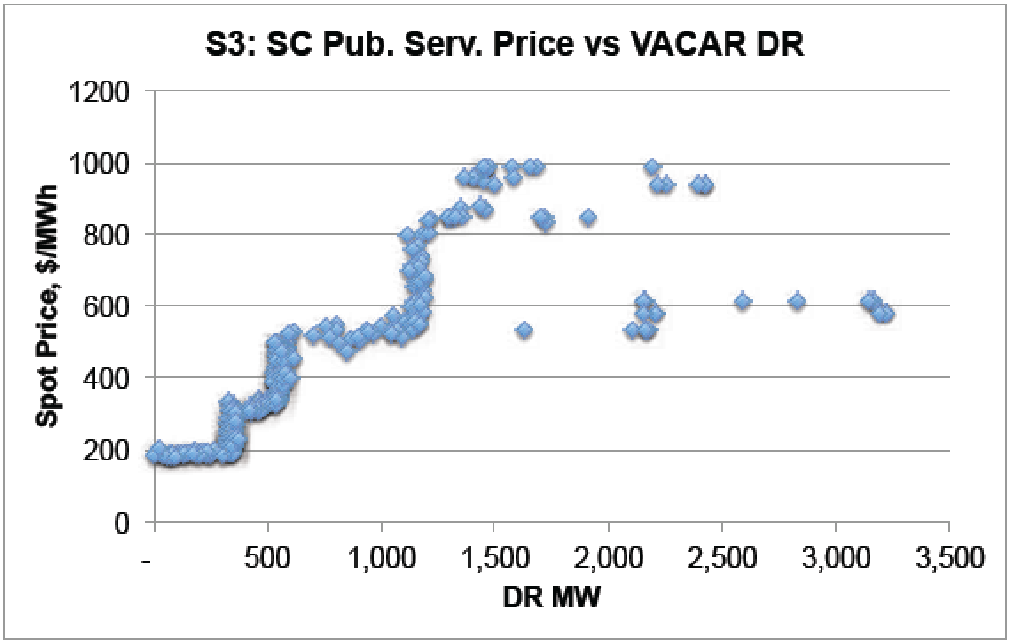


Figure 4-8. DR Grows as Prices Increase

Figure 4-8 shows significant increases in the amount of DR called upon as the spot prices increase. At $200/MWh, 500 MWs of DR is called upon in the VACAR region while at $1000/MWh 1,500-2,500 MWs of DR is called upon. This dispatch pattern is consistent with the step function deployed in Task 9 for modeling DR dispatch.

4.3 Locational Marginal Prices (LMPs)

Locational marginal prices are calculated by the GE MAPS model and represent spot prices for electric power. Higher prices will occur where there is a shortage of both low-cost generation and transmission to meet loads. If low-cost generation is not available in a region, it can be imported if there is enough transmission. If the dispatch of low cost generation results in transmission constraints, the GE MAPS optimization dispatches higher cost generation in order to minimize production cost while meeting load serving requirements and respecting transmission constraints.

The next three figures (Figures 4-9 through 4-11) show average locational marginal prices (LMPs) for the Eastern Interconnection as a whole and for selected regions. For each of the graphs dark blue is the lowest cost moving through color palette to bright red, which is the highest cost.

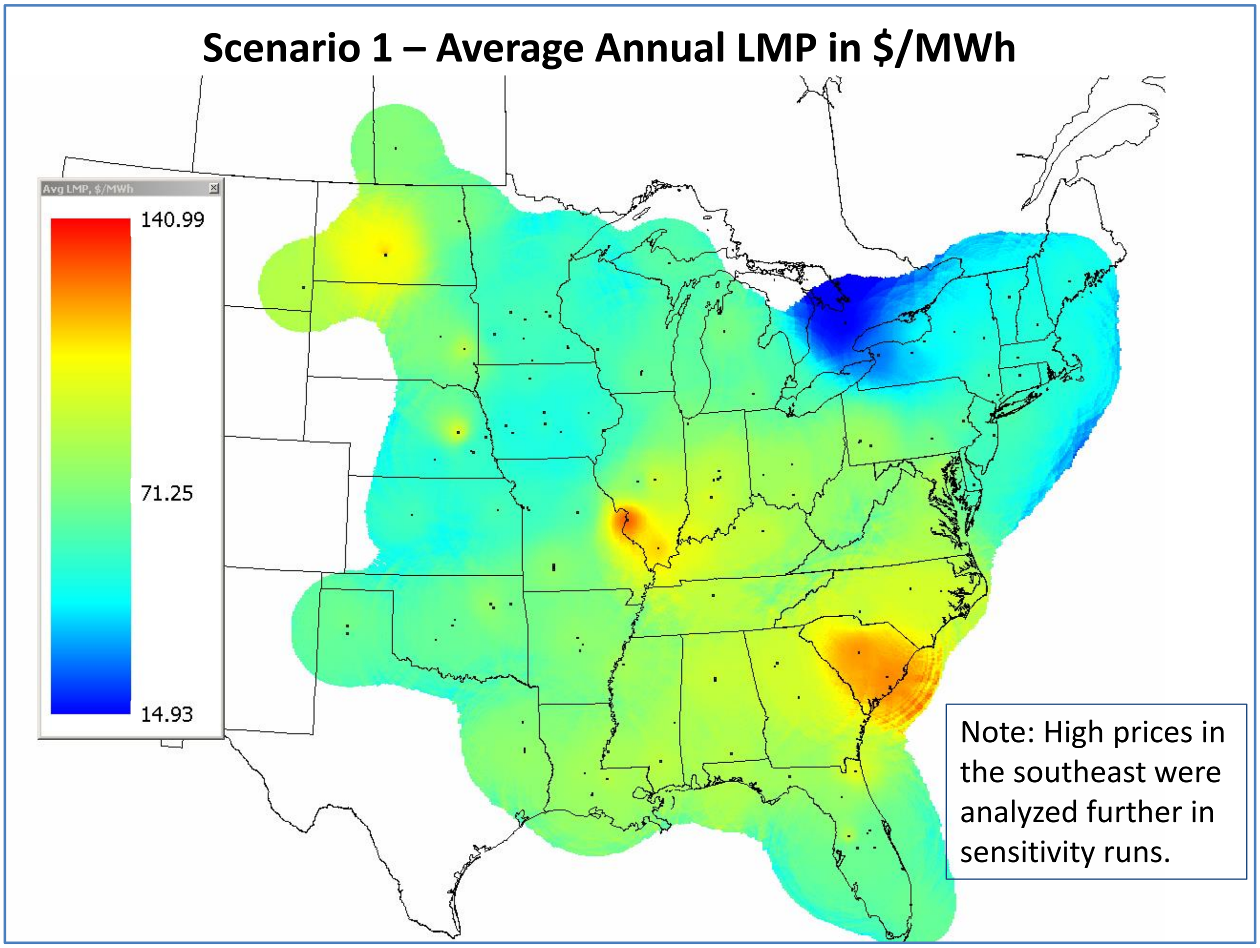


Figure 4-9. Scenario 1: CP Average Annual LMP in $/MWh

For the Scenario 1: CP Base modeling run (Figure 4-9), the average annual LMP map shows a range in prices of $14.93/MWh in portions of Ontario, Canada to $140.99/MWh in the southeast. Generally lower prices are exhibited in the areas that have significant deployments of wind resources and higher prices in the areas without wind resources. One exception is higher prices in North Dakota. There are significantly constrained flowgates in MAPP_US, likely driving these localized higher prices.

As discussed above the transmission system represented in each GE MAPS model was designed to meet the assumptions of the scenario during the one or two hours that were modeled during the Task 7 & 8 power flow analysis, not for every single hour of the year. Once GE MAPS dispatched the system differently than was assumed in the power flow cases, adequate transmission was not always in place to accommodate this dispatch pattern thus creating congestion and high LMP's. It should also be noted that although LMPs are depicted for the entire footprint modeled, there are no actual Locational Marginal Prices in the southeast. Also, as with other aspects of the project, in a more detailed transmission planning exercise this would typically be addressed with more iterations and analysis, involving different transmission and generation configurations that would be designed to lower the LMP prices.

The high prices in the southeast were further analyzed in the sensitivity analysis with the addition of some transmission elements. Those results are discussed in Section 6 of the report.

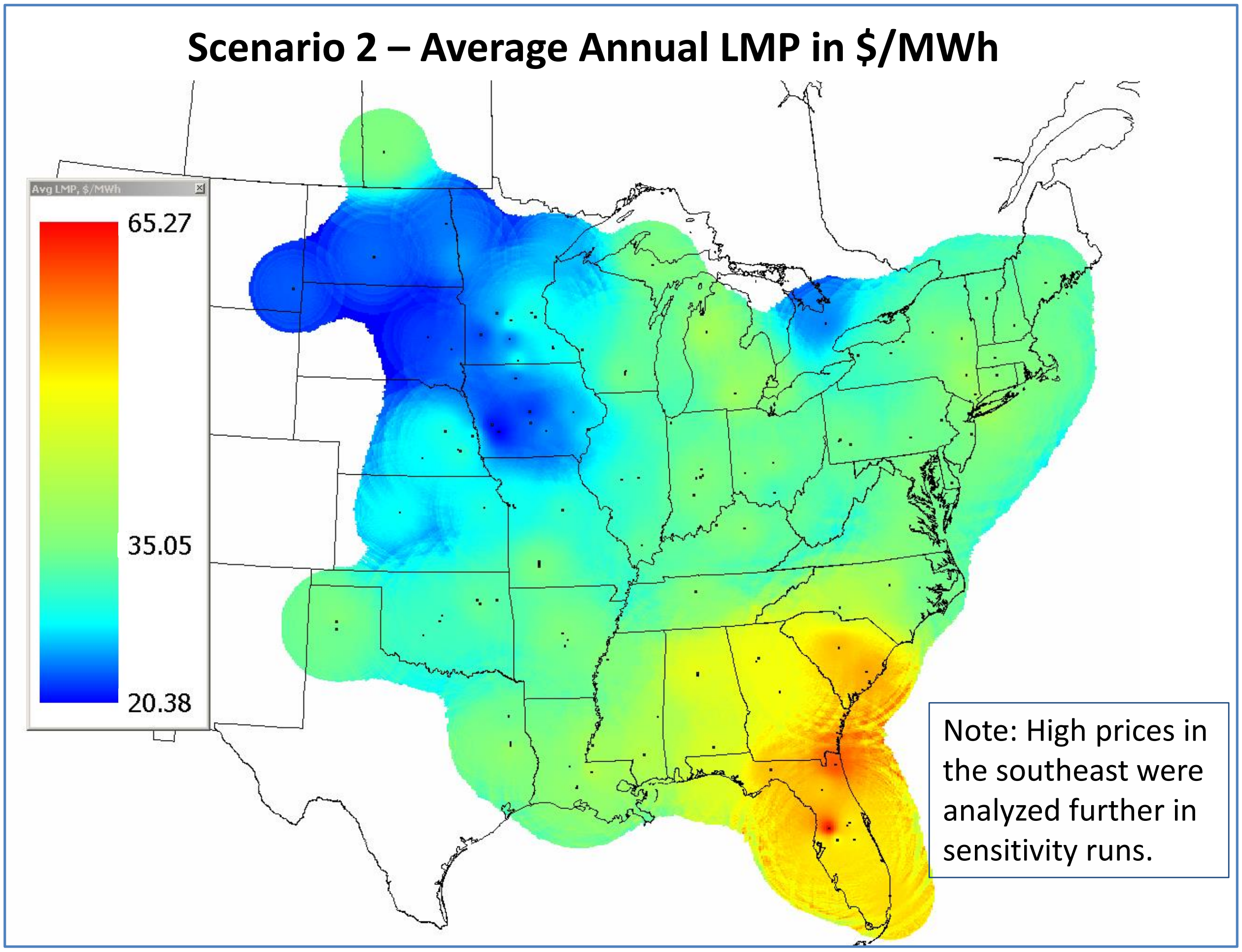


Figure 4-10. Scenario 2: NRPS/IR: Average Annual LMP in $/MWh

Figure 4-10 shows average spot prices for the Scenario 2: NRPS/IR Base modeling run. Scenario 2: NRPS/IR exhibited the smallest range of prices – from $20.38/MWh to $65.27/MWh – across the three scenarios. The dispersion of high and low prices is relatively consistent with the results from the Scenario 1: CP Base modeling run, with lower prices in regions with significant wind deployments and the highest prices in the southeast.

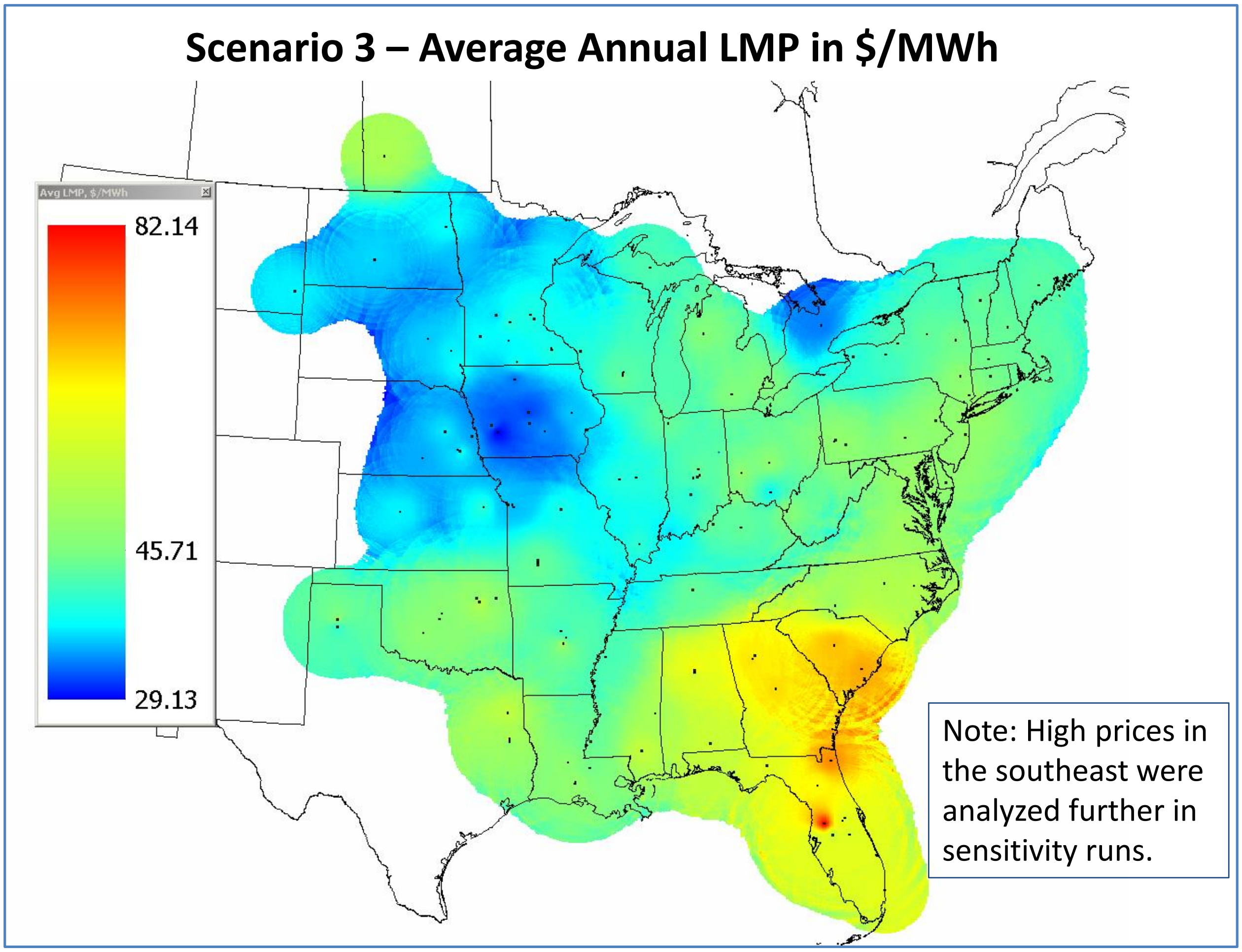


Figure 4-11. Scenario 3: BAU: –Average Annual LMP

Figure 4-11 shows average LMPs for the S3 Base modeling run. The range of prices - $29.13/MWh to $82.14/MWh - is smaller than Scenario 1: CP but slightly greater than Scenario 2: NRPS/IR. Again, consistent with the results from Scenarios 1: CP and 2: NRPS/IR, the lower prices are in regions with significant wind resources. Very low prices in the MISO West region may indicate that the wind resources in the area cannot be exported to some of the higher cost regions to the east.

4.4 Generation Dispatch

Figures 4-12, 4-13 and 4-14 depict the mix of generation resources at each hour of the year for the three scenarios' Base modeling runs. Figure 4-12 exhibits a vastly different generation supply mix, with combined cycle, nuclear and wind resources being predominant, some photovoltaic (PV) facilities and a much higher use of demand response. The Scenario 2: NRPS/IR Base modeling run (Figure 4-13) shows a more balanced mix of generation dispatch which is expected because of the more diverse mix of capacity available to be dispatched. In the Scenario 3: BAU Base modeling run (Figure 4-14) the generation mix consists primarily of combined cycle, coal and nuclear units, with relatively little amounts of wind, IGCC and demand response.

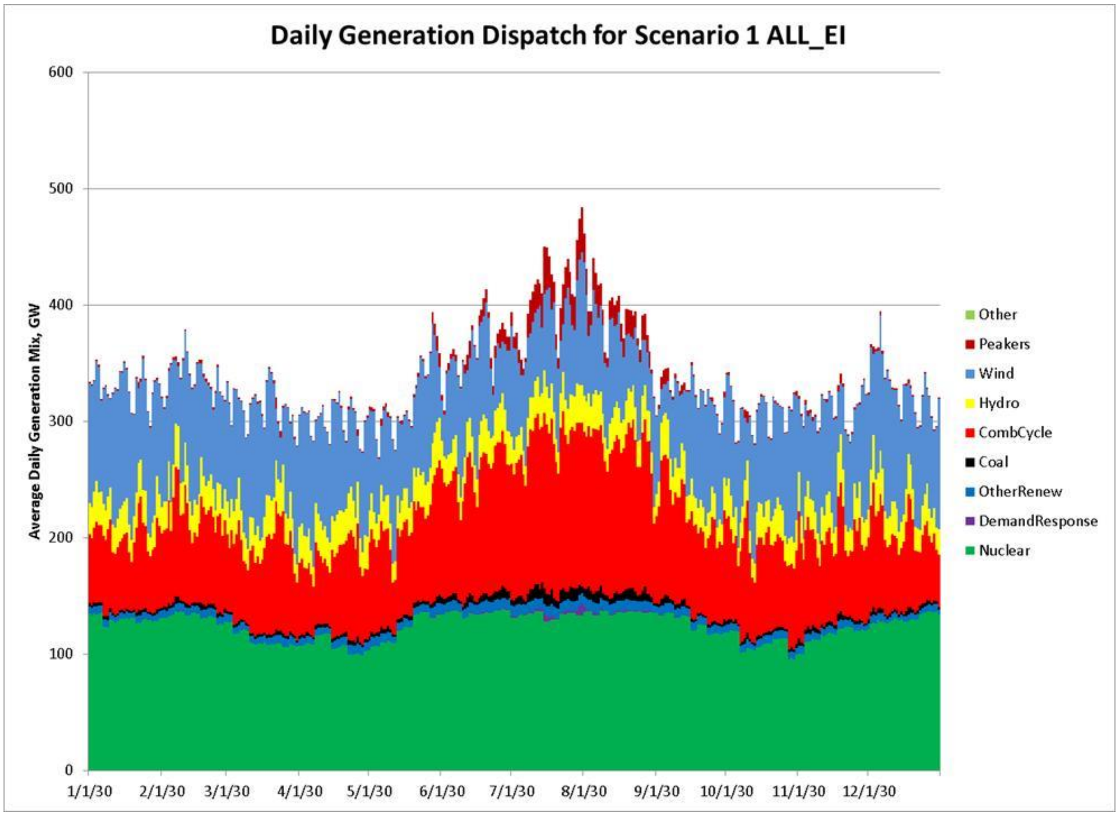


Figure 4-12. Scenario 1: CP: Combined Policy – ALL EI Generation Dispatch

Figure 4-12 depicts the hourly generation dispatch across the entire Eastern Interconnection for Scenario 1: CP. The dispatch pattern shows the heavy reliance on nuclear, combined cycle and wind plants to achieve the desired policy outcomes.

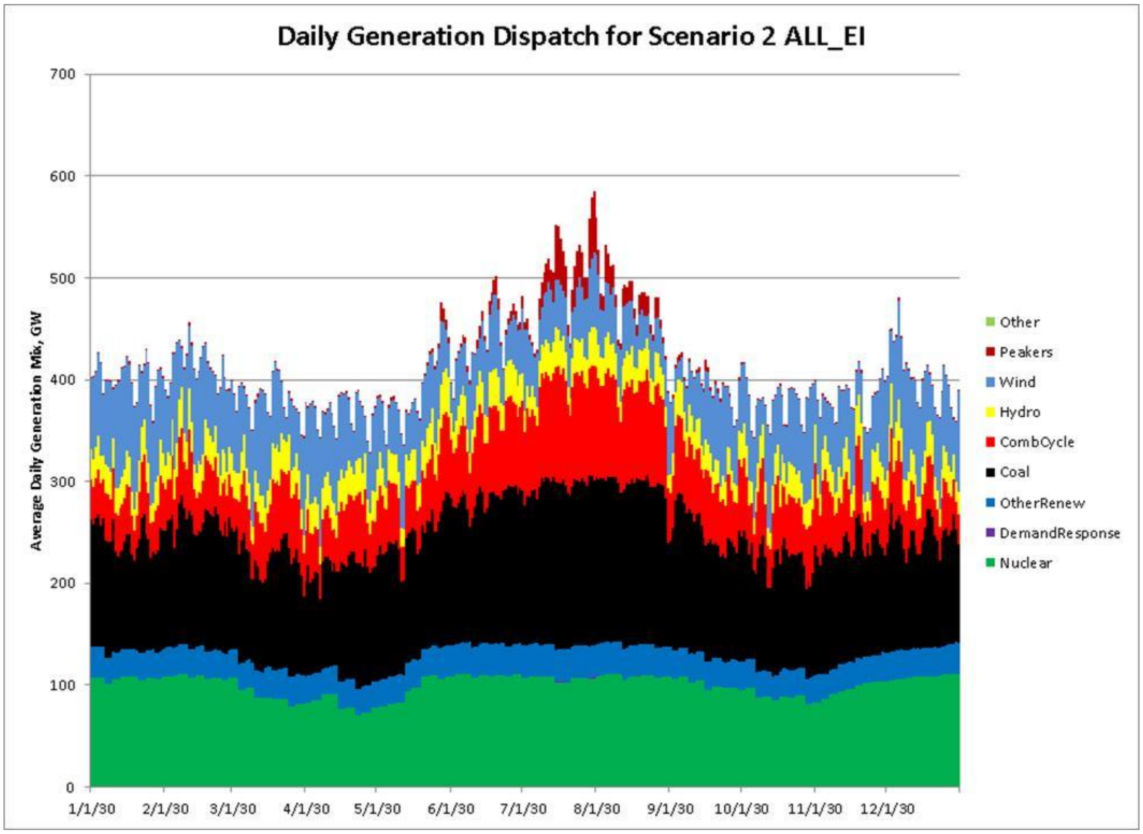


Figure 4-13. Scenario 2: NRPS/IR: RPS Regionally Implemented – ALL EI Generation Dispatch

Figure 4-13, showing the hourly dispatch for Scenario 2: NRPS/IR, shows the more balanced portfolio of resources being utilized once the 30% renewable mandate is met. The RPS mandate is met by a combination of Other Renewables which is layered over the nuclear output and the Wind generation, shown in the blue near the top of the graph and hydro, shown in yellow. A significant amount of coal is utilized as well as combined cycle plants.

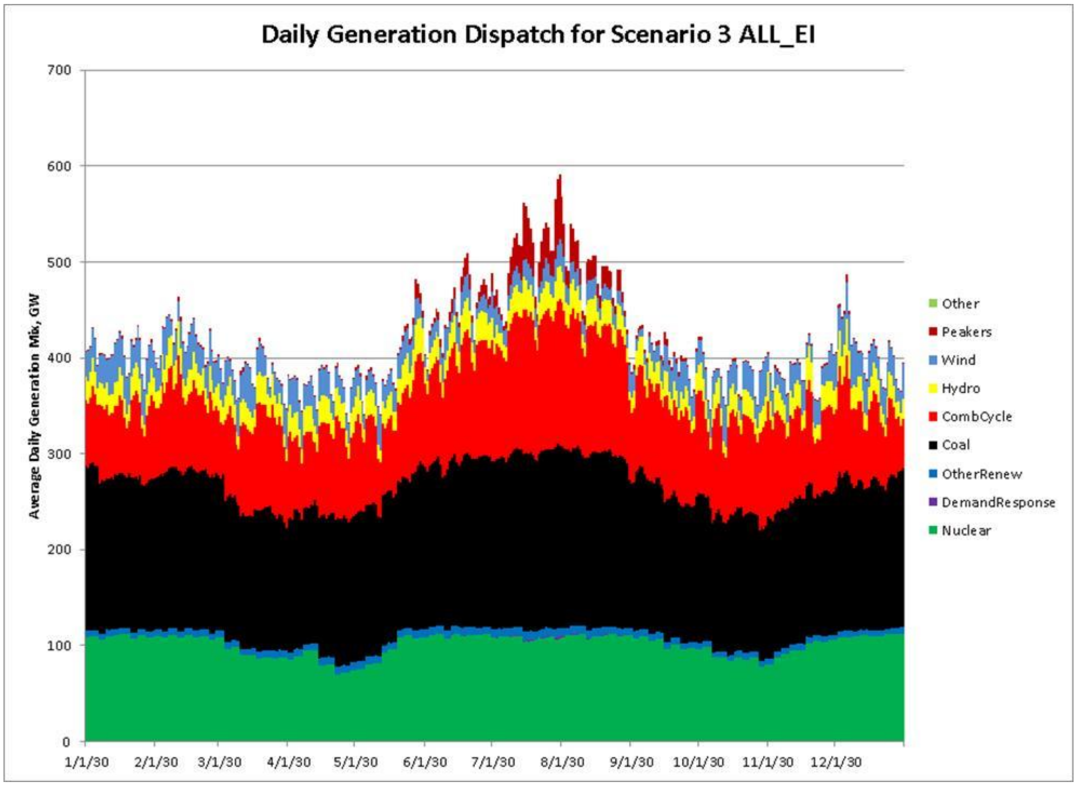


Figure 4-14. Scenario 3: BAU: Business As Usual – ALL EI Generation Dispatch

Figure 4-14 demonstrates the use of mostly conventional resources to meet the loads specified in the scenario. Energy production is dominated by nuclear, coal and combined cycle with smaller amounts of renewables, including wind, hydro and other renewables.

5 Task 10 Process and Results

Task 10 involved the development of high level transmission and generation cost estimates for the three Phase 2 transmission scenarios. These costs are a refinement of the costs developed in Phase 1 which were extremely high level. At the request of stakeholders the EIPC also developed "Other Costs" including the costs for Energy Efficiency, Demand Response, Distributed Generation, Wind Integration and Nuclear Decommissioning, based on cost information developed in Phase 1 and final results from the production cost work done in Task 9.

5.1 Transmission Costs

In accordance with the SOPO, the transmission costs presented here are still very high level costs and, except in rare instances, do not include costs for any transmission enhancements for lines and transmission elements below 230 kV level. There were instances where a Planning Authority did add projects below 230 kV and provided cost estimates for those projects. This was typically done where there were no facilities 230 kV or above and they were needed. The majority of issues below 230 kV were not addressed; addressing them would create additional costs to what is presented in this report.

In Phase 1, high level transmission costs were developed utilizing generic transmission line building blocks in a consistent manner by each of the Planning Authorities (PAs) to approximate the SSC requested increases in transfer capability represented in each macroeconomic future. No power flow analyses were performed; PAs determined the termination points for the transmission line building blocks based on knowledge of their local system(s). In general, only transmission needs between regions were considered – as determined by the NEEM analysis and the "Soft Constraint Methodology". The integration of remote resources and large blocks of resource additions were considered as needed on a case-by-case basis. In some limited locations high voltage direct current HVDC solutions were considered.

In Phase 1, EIPC also compiled a cost matrix of strategic level, "cost per mile" estimates for common high voltage alternating current (HVAC) voltage levels among the PAs. The EIPC Steady State Modeling Load Flow Working Group (SSMLFWG) determined that the NEEM regions represented enough geographic diversity to warrant differences in regional costs. The cost matrix was developed to provide the cost per mile ranges for typical transmission line voltage types by applying a range of regional multipliers to the base cost for each NEEM region.

In Phase 2, these costs were refined by replacing generic transmission line building blocks with projects developed by the PAs for generation interconnection and constraint relief. Load flow analysis was performed and the transmission system was developed to meet the contingency tests described in Tasks 7 and 8.

Phase 2 costs for the projects were developed similarly to how the costs were developed for Phase 1 with strategic level "cost per mile" estimates for the different voltages of transmission lines combined with regional multipliers. The costs included:

1. Costs for new lines at different voltages and MW capability, both overhead and underground;

2. Regional multipliers for the costs of new lines;
3. Costs for reconductored facilities by voltage and MW capability;
4. Costs for upgraded operating temperature facilities by voltage and MW capability;
5. Costs for HVDC facilities;
6. Costs for new substations by voltage level;
7. Regional multipliers for new substations;
8. Substation upgrade costs by voltage level;
9. New capacitor banks; and
10. New transformer costs by voltage.

Tables 5-1 through 5-8 provide the cost estimates and regional multipliers used for estimating the transmission costs. The cost assumptions are the same as were used in Phase 1. The transmission build-out is more detailed but the costs are still high-level indicative costs.

Table 5-1. Costs for New Lines

Transmission Line Cost Estimate Matrix - New Facility				
				Base Cost
	Voltage (kV)	# of Circuits	MW Capability	$M/Mile
New	<230	1	300	$1.1
	230	1	600	$1.2
	230	1	900	$1.6
	230	2	1200	$1.8
	345	UG	500	$19.8
	345	1	900	$2.1
	345	1	1800	$2.5
	345	UG	1800	$25.0
	345	2	3600	$2.8
	345	UG	3600	$28.0
	500	1	2600	$3.5
	765	1	4000	$5.6

Table 5-2. NEEM Regional Multipliers for New Lines

NEEM Regional Multipliers (Range)

ENTERGY	FRCC	IESO	MAPP_CA	MAPP_US	MISO_IN	MISO_MI	MISO_MO_IL	MISO_W	MISO_WUMS	NE	NEISO
1.0 - 1.8	0.7 - 1.4	0.4 - 0.8	0.3 - 0.6	0.5 - 0.9	0.5 - 1.6	0.5 - 1.6	0.5 - 1.6	0.5 - 1.6	0.5 - 1.6	0.7 - 1.1	1.8 - 2.7
1.2 - 2.0	1.3 - 2.2	0.8 - 1.9	0.3 - 0.6	0.8 - 1.3	0.4 - 0.9	0.4 - 0.9	0.4 - 0.9	0.4 - 0.9	0.4 - 0.9	0.7 - 1.4	
0.9 - 1.6	1.3 - 1.9			0.6 - 1.1	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9	0.5 - 0.9	1.9 - 3.8
1.1 - 1.7	1.1 - 1.7	0.8 - 1.4	0.3 - 0.5	1.0 - 1.1	0.7 - 1.5	0.7 - 1.5	0.7 - 1.5	0.7 - 1.5	0.7 - 1.5	0.7 - 1.3	
											0.5 - 0.8
1.4 - 2.2				0.5 - 0.8	0.5 - 0.8	0.5 - 0.7	0.3 - 0.6	0.5 - 0.7	0.5 - 0.8	0.5 - 1.0	1.4 - 2.9
1.3 - 2.1			0.6 - 1.0	0.6 - 0.9	0.6 - 0.8	0.6 - 0.7	0.4 - 0.6	0.6 - 0.7	0.6 - 0.8	0.4 - 0.8	0.8 - 2.0
									0.7 - 1.0		
			0.6 - 1.0		0.7 - 0.8	0.7 - 1.0	0.7 - 0.8	0.7 - 0.9	0.9 - 1.0	0.6 - 1.1	1.1 - 2.1
									0.7 - 1.0		
0.9 - 1.5	0.7 - 1.2		0.4 - 1.0	0.4 - 0.7	0.5 - 0.7		0.5 - 0.7	0.5 - 0.7	0.6 - 0.8	0.5 - 0.9	
0.8 - 0.9					0.5 - 0.7	0.5 - 0.9	0.5 - 0.6	0.5 - 0.6	0.6 - 0.7	0.4 - 0.8	

Non_RTO_Midwest	NYISO_A-F	NYISO_GHI	NYISO_J_&_K	PJM_Eastern_MAAC	PJM_Rest_of_MAAC	PJM_Rest_of_RTO	SOCO	SPP_N	SPP_S	TVA	VACAR
1.4 - 2.3	0.9 - 1.8	0.9 - 1.8	9.1 - 18.2					0.7 - 1.1	0.7 - 1.1	0.7 - 1.2	0.7 - 1.1
	1.3 - 2.6	1.3 - 2.6					0.7 - 1.7	0.7 - 1.4	0.7 - 1.4	0.8 - 1.7	0.7 - 1.1
							0.6 - 1.3	0.5 - 0.9	0.5 - 0.9	0.7 - 1.4	0.5 - 1.0
							0.6 - 1.3	0.7 - 1.3	0.7 - 1.3	0.7 - 1.3	0.5 - 1.0
			1.2 - 1.5								
1.0 - 1.7	1.7 - 2.4	1.7 - 4.3						0.5 - 1.0	0.5 - 1.0		
0.8 - 1.4						1.3 - 1.6		0.4 - 0.8	0.4 - 0.8		
1.4 - 2.1								0.6 - 1.1	0.6 - 1.1		
0.9 - 1.5				3.6 - 4.4	2.1 - 2.5	1.1 - 1.4	0.7 - 1.1	0.5 - 0.9	0.5 - 0.9	0.6 - 0.9	0.3 - 0.6
				2.5 - 3.0	2.3 - 2.8	0.8 - 0.9		0.4 - 0.8	0.4 - 0.8		

Table 5-3. Costs for Reconductored Facilities

Transmission Line Cost Estimate Matrix - Reconductored Facility

	Voltage (kV)	# of Circuits	MW Capability	Base Cost $M/Mile	EIPC NEEM Regional Multiplier
Reconductors	<230	1	300	$1.1	0.6
	230	1	600	$1.2	0.6
	230	1	900	$1.6	0.6
	230	2	1200	$1.8	0.6
	345	1	900	$2.1	0.6
	345	1	1800	$2.5	0.6
	345	2	3600	$2.8	0.6
	500	1	2600	$3.5	0.6
	765	1	4000	$5.6	0.6

Table 5-4. Costs for Upgraded Facilities

Transmission Line Cost Estimate Matrix - Upgraded Operating Temperature Facility					
				Base	EIPC
	Voltage (kV	# of Circuits	MW Capability	$M/Mile	NEEM Regional Multiplier
Upgrades	<230	1	300	$1.1	0.2
	230	1	600	$1.2	0.2
	230	1	900	$1.6	0.2
	230	2	1200	$1.8	0.2
	345	1	900	$2.1	0.2
	345	1	1800	$2.5	0.2
	345	2	3600	$2.8	0.2
	500	1	2600	$3.5	0.2
	765	1	4000	$5.6	0.2

Table 5-5. Costs for HVDC Facilities (500 kV)

Transmission Line Cost Estimate Matrix - HVDC					
					EIPC
	Voltage (kV)	# of Circuits	MW Capability	Base Cost	NEEM Regional Multiplier
HVDC	HVDC	bipole	3500	$1.6 Mil/Mile	1.0
	HVDC Terminal (both ends)			$550 Mil	1.0

Table 5-6. Costs for New Substations

Substation Cost Estimate Matrix - New Facility		
		Base Cost
	Voltage (kV)	$M/4 Bay SS
New	<230	$7.8
	230	$9.5
	345	$16.0
	500	$26.5
	765	$44.0

Table 5-7. Multipliers for New Substations

NEEM Regional Multipliers (Range)											
ENTERGY	FRCC	IESO	MAPP_CA	MAPP_US	MISO_IN	MISO_MI	MISO_MO_IL	MISO_W	MISO_WUMS	NE	NEISO
1.0 - 1.1			1.2 - 1.4	0.5 - 0.6	2.2 - 2.4	2.2 - 2.4	2.2 - 2.4	2.2 - 2.4	0.8 - 1.0	0.3 - 0.4	2.6 - 3.9
0.8 - 1.2	0.6 - 0.8		1.4 - 1.6	0.6 - 0.8	1.8 - 2.0	1.8 - 2.0	1.8 - 2.0	1.8 - 2.0	0.9 - 1.1	0.4 - 0.6	
0.5 - 1.2				1.2 - 1.5	1.4 - 1.6	1.4 - 1.6	1.4 - 1.6	1.4 - 1.6	0.8 - 0.9	0.4 - 0.7	1.7 - 2.6
0.4 - 0.5	0.8 - 1.1		0.9 - 1.0	1.1 - 1.3							
0.9 - 1.1					0.9 - 1.1	0.9 - 1.1	0.9 - 1.1	0.9 - 1.1		0.8 - 1.0	
Non_RTO_Midwest	NYISO_A-F	NYISO_GHI	NYISO_J_&_K	PJM_Eastern_MAAC	PJM_Rest_of_MAAC	PJM_Rest_of_RTO	SOCO	SPP_N	SPP_S	TVA	VACAR
NEEM Regional Multipliers (Range)											
0.4 - 0.7								0.3 - 0.4	0.3 - 0.4	0.8 - 1.0	
							0.6 - 0.8	0.4 - 0.6	0.4 - 0.6		0.8 - 1.2
0.9 - 1.1	0.9 - 1.9	0.9 - 1.9						0.4 - 0.7	0.4 - 0.7		
0.8 - 1.1							0.8 - 1.1			0.8 - 0.9	0.9 - 1.1
								0.8 - 1.0	0.8 - 1.0		

Table 5-8. Costs for Upgrading Substations and New Transformers

Substation Cost Estimate Matrix - Upgrade Facility			
		Base Cost	EIPC
Upgrades	Voltage (kV)	$M/Bay	NEEM Regional Multipliers
	<230	$2.0	1.0
	230	$2.5	1.0
	345	$3.0	1.0
	500	$5.0	1.0
	765	$11.0	1.0

Transformer Cost Estimate Matrix - New Facility			
		Base Cost	EIPC
New	Voltage (kV)	$M/XFMR	NEEM Regional Multipliers
	230	5.5	1.0
	345	8.5	1.0
	500	22.75	1.0
	765	42.5	1.0

5.2 Results by Scenario

These costs and multipliers were applied to each individual project that was developed as part of Tasks 7 and 8. The costs were aggregated into different categories: generation interconnection project costs, constraint relief project costs, and voltage support costs. Below are the total costs broken out into these categories for each scenario. The costs are shown below in Table 5-9 and are "overnight capital costs", as if all the facilities were built in 2030. Note that the constraint relief costs estimated in these tables involve transmission needed to relieve reliability constraints – overloaded transmission elements and voltages that were too high or too low. They do not include the transmission that would be needed to relief congestion constraints.

Table 5-9. Costs by Generation Interconnection, Constraint Relief and Voltage Support

	All Costs in $2010 Billions											
	Total Scenario Costs		Generation Interconnection Project Costs		Constraint Relief Project Costs						Voltage Support Project Costs	
					Total		Task 7		Task 8			
	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
Scenario 1	$81.75	$115.16	$38.95	$60.16	$42.41	$54.41	$39.35	$50.76	$3.06	$3.65	$0.38	$0.59
Scenario 2	$55.06	$79.67	$44.68	$63.98	$10.33	$15.59	$9.26	$14.22	$1.07	$1.38	$0.06	$0.10
Scenario 3	$12.27	$18.50	$5.18	$9.50	$6.95	$8.81	$5.84	$7.39	$1.11	$1.42	$0.13	$0.18

The costs reflected in Table 5-8 were also broken out by new and existing facilities (shown below in Table 5-9). The existing facility costs reflect the cost to upgrade or reconductor facilities. Not included in this summary are the voltage support project costs, which were small compared to the generation interconnection and constraint relief costs. These costs are also calculated as overnight capital costs in 2030.

Table 5-10. Costs by New and Existing Facilities

	All Costs in $2010 Billions								
	Generation Interconnection Project Costs			Constraint Relief Project Costs					
				Task 7			Task 8		
	New Facilities		Existing Facilities	New Facilities		Existing Facilities	New Facilities		Existing Facilities
	Low	High	Cost	Low	High	Cost	Low	High	Cost
Scenario 1	$35.88	$57.09	$3.07	$34.97	$46.37	$4.38	$0.96	$1.56	$2.10
Scenario 2	$39.93	$59.24	$4.75	$6.95	$11.91	$2.31	$0.58	$0.89	$0.49
Scenario 3	$5.01	$9.33	$0.17	$4.03	$5.58	$1.81	$0.50	$0.81	$0.62

Total transmission capital costs are significantly higher for Scenario 1: CP than for either Scenario 2: National Renewable Portfolio Standard/ Implemented Regionally (NRPS/IR) or 3. In all cases both voltage support costs and the upgrades and reconductor of existing lines are very small percentages of the total costs.

In Scenario 1: CP the split of the costs is approximately equal between generation interconnection projects and constraint relief projects. Scenario 3: BAU has much lower transmission costs but also has approximately half needed for generation interconnection and about half needed for constraint relief projects with a very small amount for voltage support. Scenario 2: NRPS/IR has a different outcome with approximately 80% of the total costs needed for generation interconnection projects and 20% needed for constraint relief projects.

5.2.1 <u>Generation Costs</u>

Generation costs were calculated similarly to the transmission costs in the sense that regional multipliers were developed and applied to generic capital costs for different types of generating plants. In the Phase 2 effort, however, PAs had specific power plants to apply the costs to, rather than generic MWs of generating plant types per NEEM region. The generic capital costs were the same as those used in Phase 1[4] and are shown below.

Table 5-11. Generic Capital Costs

EIPC New Capacity Capital Cost ($)				
Fuel Type	New Capacity (MW) S1	New Capacity (MW) S2	New Capacity (MW) S3	Base Capital Cost ($/MW)
Biomass	0	0	0	3,128,907
CC	2,734	1,185	2,786	984,750
CT	0	0	0	678,080
Coal	0	0	0	2,742,707
Geo-Thermal	0	0	0	3,748,820
Hydro	0	0	0	3,098,000
LFG	107	107	107	2,400,137
Nuclear	0	0	0	5,080,991
Pumped Storage	0	0	0	
PV	85	104	103	3,825,920
Solar	0	0	0	3,775,520
STOG	0	0	0	
Steam Wood	185	185	0	3,128,907
Wind	100	0	0	2,216,120
IGCC	0	0	0	3,100,857
Wind OFFS	0	0	0	4,801,920

Below in Tables 5-11 and 5-12, the total costs are shown for each of the three Base modeling runs. Table 5-11 shows the costs by generation type and Table 5-12 shows costs by NEEM region. In terms of total generation capital costs, Scenario 1: CP costs are approximately 3.5 times higher than Scenario 3: BAU and 28% higher than Scenario 2: NRPS/IR.

[4] The capital costs in Phase 1 were developed using the Energy Information Administration's Annual Energy Outlook 2011.

Table 5-12. Scenario Base Capital Costs ($2010 B) by Generation Type

Fuel Type	Total Cost (2010$ B)	Total Cost (2010$ B)	Total Cost (2010$ B)
	S1	S2	S3
Biomass	$5.8	$72.2	$9.1
CC	$105.5	$31.5	$61.6
CT	$4.0	$15.4	$10.0
Coal	$0.0	$0.2	$0.0
Geo-Thermal	$0.0	$0.0	$0.0
Hydro	$15.3	$20.2	$2.2
LFG	$7.0	$7.0	$6.4
Nuclear	$143.8	$11.8	$11.4
Pumped Storage	$0.0	$0.0	$0.0
PV	$23.2	$25.7	$25.2
Solar	$0.2	$0.2	$0.2
STOG	$0.3	$0.8	$0.8
Steam Wood	$1.3	$1.3	$0.4
Wind	$554.0	$321.0	$107.3
IGCC	$0.0	$0.0	$0.0
Wind OFFS	$7.6	$172.0	$7.6
Total EI	$ 868.1	$ 679.4	$ 242.3

Table 5-13. Scenario Base Capital Costs ($2010 B) by NEEM Region

Region	Total Cost (2010$ B)	Total Cost (2010$ B)	Total Cost (2010$ B)
	S1	S2	S3
ENT	$3.81	$2.24	$3.17
FRCC	$93.03	$11.89	$8.25
MAPP_US	$19.94	$15.41	$3.46
MISO_IN	$33.99	$2.36	$5.85
MISO_MI	$21.36	$17.93	$2.78
MISO_MO_IL	$28.43	$2.20	$1.17
MISO_W	$165.91	$40.86	$16.07
MISO_WUMS	$10.97	$4.09	$6.97
Nebraska	$35.49	$5.67	$0.22
NEISO	$19.86	$18.24	$17.85
Non-RTO-Midwest	$7.82	$3.04	$1.18
NYISO_A-F	$14.68	$7.97	$8.82
NYISO_GHI	$0.83	$0.31	$1.80
NYISO_JK	$2.33	$3.38	$3.28
PJM_E	$15.59	$55.70	$15.39
PJM_ROM	$11.61	$32.19	$27.61
PJM_ROR	$50.70	$117.71	$25.80
SOCO	$44.59	$22.24	$7.80
SPP-North	$94.38	$24.60	$2.48
SPP-South	$92.18	$57.67	$8.69
TVA	$6.19	$19.94	$5.51
VACAR	$37.95	$154.07	$20.93
IESO	$44.51	$44.51	$44.51
MAPP_CA	$11.92	$15.16	$2.70
Total EI	$ 868.1	$ 679.4	$ 242.3

5.2.2 Other Costs

A number of other costs were developed as part of Phase 1. In Phase 1, the Stakeholder Steering Committee (SSC) directed the Modeling Working Group (MWG) to develop high-level cost estimates associated with the assumptions defined in some of the futures and a few sensitivities to capture costs not accounted for in the MRN-NEEM modeling or in the GE MAPS modeling. The costs that apply to the chosen scenarios include:

1. Energy Efficiency Costs
2. Demand Response Costs
3. Distributed Generation Costs
4. Nuclear Uprate Costs

5. Variable Energy Resource integration costs
6. Pollution Retrofit Costs

Energy Efficiency Costs were estimated using two studies: a 2009 Georgia Institute of Technology study entitled "Energy Efficiency in the South" and a 2009 McKinsey & Company study entitled "unlocking Energy Efficiency in the U.S. Economy." Both sources showed modest costs for energy efficiency penetrations; less than 28% to 33%, with cost estimates ranging from close to $0-/MWh to $20-$40MWh. For both studies, costs increased dramatically once a certain penetration level was reached. The McKinsey study showed costs increasing to approximately $90/MWh at 28% electricity reduction while the Georgia Tech study showed prices increasing to approximately $160/MWh at 33% reduction in electricity. Beyond that level of penetration, the SSC kept the costs flat for reductions up to 50%. Scenario 3: BAU had a base level of energy efficiency that was cost-estimated. This base level also applied to Scenario 2: NRPS/IR. Scenario 1: CP had a much higher level of energy efficiency that was cost estimated; in addition, because Scenario 1: CP had very high CO_2 costs, the energy efficiency costs were disaggregated into energy efficiency costs due to CO_2 costs and additional energy efficiency.

Demand Response Costs in Phase 2 include costs for DR capital expenditures in the year 2030 and annual O&M costs in 2030. The capital costs were based on estimating the costs per meter ($240/meter) multiplied by the number of meters assumed in 2030. The O&M costs were estimated for all the meters in use in 2030. The dispatch costs of Demand Response are not included in the cost estimates.

Distributed Generation (DG) Costs reported in Phase 1 for Future 8 (which became Scenario 1: CP) were based on assumption that all DG was behind the meter with photovoltaic systems. The costs in Phase 1 were estimated as Net Present Value of annual DR costs (capital charge rate and O&M) from 2015-2020. In reviewing the costs during Phase 2 it became clear that the significant energy reductions in Future 8/Scenario 1: CP were due to the combination of CO_2 price, energy efficiency policies and DG development. It is clear in the Scenario how much of the reductions were due to the CO2 price but it had never been decided exactly what proportion of the remaining reductions were due to policy driven energy efficiency versus DG.

The maximum amount of DG in Future 8/Scenario 1: CP would be the same amount as was assumed in Future 4 in Phase 1 – 24 GW of behind the meter photovoltaic systems which produced 29 TWh of energy. The overnight capital cost for the 24 GW of photovoltaics is estimated at $83.4 billion. Assuming a conservative 10% carrying charge, this would make the annual cost per MWh for DG approximately $2,875/MWh. The cost for energy efficiency costs were estimated at $8.9 billion of annual cost for 541 TWh of savings, resulting in a cost of approximately $16/MWh. Because of the significant price disparity, it was assumed that all reductions in in energy use would come as a result of energy efficiency and there would be no DG, resulting in zero cost.

Nuclear Uprate Costs were not captured in the MRN-NEEM model nor were they captured in GE-MAPS. Scenario 3: BAU included 1,538 MW of nuclear uprates. This amount was included as a base assumption in both Scenarios 1: CP and 2: NRPS/IR in the same amounts. The SSC directed the MWG to estimate the cost of the nuclear uprates based on $2,600/kW. Thus, the resulting estimated costs for the nuclear uprates are $4.9 billion all three scenarios. These estimated costs were based on the same assumptions for new nuclear and include an 11.2% fixed charge rate assuming 40 years of operation and a discount rate of 5%.

Variable Integration Costs involved quantifying the operational costs of integrating wind/solar generation above a 25% penetration rate. To be consistent with the other costs, the proposed approach, described below, is to apply an average integration cost to all generation from variable energy resources (VERs) in Scenario 3: BAU and to all VERs above Scenario 3: BAU penetration limits in Scenarios 1: CP and 2: NRPS/IR. Combined, this will provide the total integration costs for each future. These integration costs are a high-level estimate of operational costs only and do not include any interconnection costs. The Eastern Wind Integration and Transmission Study (EWITS) was chosen for use given that it is the study that most closely matches the EIPC geographic scope and is a relatively recent report. EWITS analyzed the operational impacts of high wind penetration scenarios that the SSC directed the MWG to reflect in this cost analysis. EWITS examined wind penetrations of 20% to 30% across the Eastern Interconnection, but analyzed much higher penetration rates within individual regions; *e.g.*, greater than 100% wind penetration in SPP for EWITS Configurations 1 and 4. There were four EWITS configurations defined for analysis in the determination of these integration costs:

1. High capacity factor, onshore wind, 20% penetration.
2. Hybrid onshore and offshore wind, 20% penetration.
3. Local wind with aggressive offshore, 20% penetration.
4. Aggressive onshore and offshore Wind, 30% penetration.

Of the four EWITS configurations, Configuration 1 (the All-Onshore Configuration) appeared to provide the best comparison to the types of results in the three Phase 2 scenarios. The EWITS Configuration 1 integration cost is $5.13/MWh (2009$). Because integration of wind is a recent phenomenon and there is not a good history of wind integration costs, the MWG decided to bound the EWITS Configuration 1 costs by a minus 50% and plus 75% range.

One additional cost that came out of the MRN-NEEM model that was not produced by the GE MAPS model (because it is a production cost model) is the Fixed O&M of generation. Fixed O&M costs were derived from the Phase 1 input assumptions.

Below is a table showing the amount of costs for the Other Costs for each scenario. These costs are expressed in $2010 as annual costs for the O&M costs and as $2010 of overnight capital costs for the capital expenditures. In Phase 1, ranges of costs were developed when the stakeholders believed the costs were very uncertain. In those cases the stakeholders developed low, medium and high estimates of particular costs.

Table 5-14. "Other Costs" Summary

"Other Costs" - O&M Costs - All costs are shown in $2010 Billions for the Year 2030									
	Scenario 1			Scenario 2			Scenario 3		
Costs	Low	Mid	High	Low	Mid	High	Low	Mid	High
Policy Driven Energy Efficiency	$ 6.4	$ 8.9	$ 11.5	$ 0.8	$ 1.5	$ 2.1	$ 0.8	$ 1.5	$ 2.1
CO2 Price Driven Energy Efficiency	$ 5.7	$ 11.5	$ 17.2	$ -	$ -	$ -	$ -	$ -	$ -
Demand Response O&M		$ 0.6			$ 0.3			$ 0.3	
Variable Resource Integration		$ 2.9			$ 2.5			$ 1.0	
Fixed O&M		$ 34.7			$ 52.1			$ 48.1	
Total O&M Costs		**$ 58.5**			**$ 56.5**			**$ 50.9**	

"Other Costs" - Overnight Capital Costs ($2010 Billions)									
	Scenario 1			Scenario 2			Scenario 3		
Costs	Low	Mid	High	Low	Mid	High	Low	Mid	High
Nuclear Uprates (through 2030)		$ 4.90			$ 4.90			$ 4.90	
Distributed Generation (through 2030)		$ -			$ -			$ -	
Pollution Retrofit Costs (2015-2030)		$ 6.80			$ 20.20			$ 22.00	
Demand Response - Capital (2030 only)		$ 0.15			$ 0.09			$ 0.09	

Thermal Integration Costs (contingency reserves) were also estimated in Phase 1 because the cost information provided with the MRN-NEEM model did not incorporate the costs associated with maintaining contingency reserves needed to maintain power system reliability in the event of the sudden loss of a large generator. In Phase 2, these costs were taken into account by adding additional transmission if it was needed after examining what happens with the loss of a large generator.

5.2.3 Caveats on Costs

The costs developed for this effort in all instances are very high-level strategic costs and are indicative only. Their best use is to compare various types of costs across the three scenarios and even then they need to be place in context. These are total costs, not costs per MWh and are for three very different policy scenarios.

Not all costs are included. The analysis did not include social benefits and costs that would arise from the different policies modeled. Also not included in the above are costs for:

1. Lower voltage transmission projects
2. SSI generation and transmission projects (common to all three scenarios)
3. Generation interconnection costs not included in the overlays, *i.e.*, the generator step-up and the lead lines to the first breaker – the costs for the generator interconnection overlays are included
4. Generation deactivation/decommissioning
5. Capital costs for existing units
6. Transmission O&M.

Lastly, the costs are in "different types of dollars." Some are annual costs and some are overnight capital costs. They cannot be added together to give an indication of the total costs for a scenario. To put all the costs into a single type of cost that could be added together would necessitate many additional financial assumptions and revenue requirements models that are outside the scope of this effort.

6 Identification of Sensitivities for Production Cost Analysis

The Task 9 production cost analysis consisted of a "base case" modeling run for each of the three scenarios (*i.e.*, Scenario1: Combined Policy (CP) Base, Scenario 2: National Renewable Portfolio Standard/Implemented Regionally (NRPS/IR) Base and Scenario 3: Business as Usual (BAU) Base). In addition, a total of six sensitivities were available for specification across all three scenarios, resulting in a total of nine modeling runs for the Task 9 analysis, using the GE MAPS model. This section includes description of and results from the six sensitivity model runs.

There were four main issues identified by stakeholders in the process that were considered for sensitivity analysis. The first of these was the amount of wind curtailment that took place in Scenario 1: Combined Policies (CP). The wind curtailment in that case averaged 15% across the Eastern Interconnection. Secondly, stakeholders were interested in testing what would happen if some of the assumptions that were made regarding load and gas prices were different from reality. A third issue was the level of Demand Response dispatched in the southeast. Three southeast regions, VACAR, SOCO and FRCC dispatched almost 80% of the total demand response MWhs used in the entire Eastern Interconnection. Lastly, high prices in the southeast were a concern. As can be seen from the graphs in Figures 4-9 through 4-11 the average LMP prices in the southeast are significantly higher than in most of the rest of the EI. The first two issues were addressed with sensitivity analysis. The last two issues were addressed with transmission upgrades included in the sensitivity runs that had been left out of the base model runs. Due to timing and resource constraints, the base models could not be re-run.

The six sensitivities chosen by the SSC are listed below. The stakeholders determined that the sensitivities would be used with Scenarios 1 and 3:

1. Scenario 1: CP – higher than expected loads;
2. Scenario 1: CP – increased spinning reserve availability;
3. Scenario 1: CP – reduced wind in high-wind areas;
4. Scenario 1: CP – increased transmission capacity on selected flowgates;
5. Scenario 3: Business as Usual (BAU): Business as Usual – higher than expected loads;
6. Scenario 3: BAU: Business as Usual – higher than expected natural gas prices.

6.1 Sensitivity Descriptions and Results

A significant concern of many stakeholders was the level of wind curtailment in Scenario 1: CP: Combined Policy. Table 6-1 below shows wind curtailment results from each of the three Scenario Base runs.

Table 6-1. Wind Curtailment Results

	S1 Base	S2 Base	S3 Base
Wind Curtailment (TWh)	131	30	1
Percent Curtailed	15%	5%	0%

The Modeling Work Group (MWG) discussed at length the possible causes for the high wind curtailment in the Phase 2 production cost modeling to develop appropriate sensitivities to reduce the wind curtailments. The MWG recommended using a number of the sensitivities in this way. Some stakeholders believed that the large wind curtailments in Scenario 1: CP could have been caused by (1) modeling assumptions or limitations in the Phase 2 production cost modeling (*e.g.* the "spin" requirements); and/or (2) the transmission build out in Phase 2 (which was intended to reliably support the generation mix and placement for that future). Other stakeholders believed that too much wind generation was sited in the wind-rich areas and that, if the wind were not going to be dispatched, it would not get built; therefore, the wind generation in the model should be reduced. Ultimately, four of the six sensitivities were chosen to try to understand the wind curtailment issue.

The four sensitivities designed to address the wind curtailment issue include:

1. Scenario 1: CP: Combined Policy – High Loads. Higher than expected loads. Loads were increased by 5% across all regions and time periods. The loads were to be increased by 8% if the GE MAPS model could solve. Because it could not solve, the increase was reduced to 5%.

2. Scenario 1: CP: Combined Policy – High Spin. Increased flexibility and availability of spinning reserves. This sensitivity was meant to examine a future in which technological advancements allow demand response to provide spinning reserves and widespread adoption of existing flexible combined cycle technology. To implement this sensitivity:

    a. Reduce spinning reserve requirements in MISO, SPP, PJM and Ontario by 50%;
    b. All combined cycle units were modeled with a 100 MW/minute ramp rate, turndown 14% of baseload, minimum runtime and downtime of 2 hours.

3. Scenario 1: CP: Combined Policy – Reduced Wind. Reduce wind build-out in the highly constrained wind regions. Tested whether the emission reduction target that is the driver for Scenario 1: CP would be achievable through optimization with a significantly lower cost wind build-out and a relatively small impact on production costs. To implement this sensitivity, the wind capacity in selected regions was uniformly scaled down by specified percentages:

    a. MISO W: scaled to 75% of base capacity
    b. NE: scaled to 61% of base capacity
    c. SPP N: scaled to 85% of base capacity
    d. MISO MO IL: scaled to 74% of base capacity.

4. Scenario 1: CP: Combined Policy – Increased Flowgates. Increase transmission capacity on selected flowgates. This is based on the assumption that the transmission build-out is not adequate in that it did not effectively address some intra-regional upgrade needs and that, if these are relieved, power will flow. To implement this sensitivity, a 50% increase in flowgate capacity was modeled for seven monitored

transmission elements that affected the top 25 most congested GE MAPS monitored flowgates (to address transmission contingency situations, multiple flowgates monitor the same element in GE MAPS). These changes were applied to the High Spin sensitivity model rather than to the Base Scenario1: CP model. The seven monitored transmission elements whose limits were increased in the sensitivity run are shown in Table 6-2. These elements were selected based on a combination of high impact on wind generation busses and a large number of "binding hours" from the base Scenario 1: CP run (transmission report "B" and hourly flowgate report "D").

Table 6-2. Scenario 1: CP Expanded Flowgate Elements

Flowgate Full Name	Existing FG Limit (fwd and reverse)	New FG limit (fwd and reverse)	Power Flow Areas (NEEM Region)	Type of Element
326 S-M: 7MCCREDIE-7MONTGMRY	1,193	1,790	MISO_MO_-MISO_MO_	345 kV line segment
5 R-M: 7MONTGMRY-7ENON fl 7L	956	1,434	MISO_MO_-MISO_MO_	345 kV line segment
320 S-M: 7MONTGMRY-7LABADIE3	1,195	1,793	MISO_MO_-MISO_MO_	345 kV line segment
13C M-M: 7PALM TAP-7SPENCER	908	1,362	MISO_MO_-MISO_MO_	345 kV line segment
7C U-M: ANTELOP3-BRDLAND3	478	717	MAPP_US -MAPP_US	345 kV line segment
3FC M-P: HILLS 3-SUB 92 3 fl	1,661	2,492	MISO_W -MISO_W	345 kV line segment
69 U-C: PRAIRIE3-P2 fl PRAIR	352	528	MAPP_US -MAPP_US	345/230 kV transformer

The EIPC process obtained stakeholder consensus on the flow gate sensitivity for the production cost analysis with one sector withholding approval. Members of the Transmission Owners/Developers caucus expressed concern with changing flow gate limits within the production cost model, without additional reliability testing, as an inappropriate method by which to seek to relieve wind curtailment. Simply increasing some flowgate capabilities at this stage of the analysis process cannot be relied upon as a reliable transmission solution. The sensitivity modeling reflects a transmission system that has not undergone the NERC reliability testing used in the EIPC effort, does not take into account the impact of relieving constraints on these certain flowgates, and does not include the costs of the transmission constraint relief in the EIPC analysis results.

The second set of concerns was addressed with the last two sensitivities:

5. Scenario 3: BAU: Business as Usual – High Loads. Higher than expected loads. Loads were increased by 5% across all regions and time periods.

6. Scenario 3: BAU: Business as Usual – High Gas. Higher than expected gas prices. Gas prices were increased by 25% across all seasons.

The extensive demand response usage and high price issues in the southeast were addressed by adding in transmission upgrades that were not included in the original base runs.

6.1.1 Sensitivity Results – Wind Curtailment

The results of the Scenario 1: CP sensitivities wind on curtailment levels are shown below in Table 6-3.

The 5% increase in load in the High Load Sensitivity increased production costs by 14% and CO_2 emissions by 15%. It reduced the wind curtailment from 131 TWhs to 119 TWhs, or approximately 10%.

The High Spin Availability sensitivity reduced production costs by 4% and CO_2 emissions by 5%. It reduced the wind curtailment from 131 TWhs to 120 TWhs or approximately 9%. The Flowgate Relief sensitivity was applied to the High Spin Availability model and decreases the production costs and CO_2 emissions slightly from the High Spin results. It does, however, decrease the wind curtailment from 120 TWhs in the High Spin Availability to 110 TWhs, reducing the overall wind curtailment by 16% when compared to the Base Case.

The Reduced Wind sensitivity increases both production costs and CO_2 emissions by 5% and reduces the wind curtailment to 64 TWhs. If compared on an absolute value basis to the wind curtailment in the Scenario 1: CP Base, this represents a 51% reduction. Comparing on a percentage basis, because of the reduced wind potential in the sensitivity, still shows a wind curtailment reduction of approximately 43%. The Reduced Wind sensitivity eliminates 35 GW of installed wind capacity in the MISO_W, Nebraska, SPP_N and MISO_MO-IL regions.

In the Scenario 1: CP Base run CO_2 emissions do not reach the 2030 target determined in NEEM, which was 291,000 short tons – the base run exceeds the target by 23%. In the sensitivity runs, the combination of High Spin and Flowgate Relief come the closest, at 16% over the target, while the High Load Sensitivity has the biggest disparity, at 42% over the target. The Reduced Wind sensitivity exceeds the target by 29%.

Table 6-3. Scenario 1: CP: Sensitivity Results

Scenario 1 Sensitivity Results					
	S1 Base	High Load	High Spin Availability	+Flowgate Relief	Reduced Wind
Production Costs ($M)					
Fuel	40,802	45,805	39552	39385	42630
Variable O&M	6,430	6,932	6457	6443	6536
Total	47,231	52,737	46010	45828	49165
CO2	45,340	52,360	43153	42825	47586
Total w/ CO2	92,571	105,097	89163	88654	96751
% Increase		14%	-4%	-4%	5%
Emissions (Short tons)					
NOx (000)	93	113	92	92	99
SO2 (000)	21	25	21	21	23
CO2 (000)	358	413	340	338	375
% Increase in CO2 over Base		15%	-5%	-6%	5%
CO2 % over Target (291)	23%	42%	17%	16%	29%
Wind Curtailment					
Wind Curtailment (TWh)	131	119	120	110	64
Percent Curtailed	0.15	0.14	0.14	0.13	0.09
% Change in Curtailment		-10%	-9%	-16%	-51%

Table 6-4 depicts the curtailment sensitivity results on a region-by region basis and shows that the bulk of the wind curtailment takes place in the handful of wind-rich regions in the Eastern Interconnection – MISO W, MISO MO-IL, MAPP US, NE and SPP N.

Table 6-4. Wind Curtailment Results by Region

	Potential Wind(TWh)		Curtailment (Twh)					Curtailment Percentage				
	Base & Others	Reduced Wind	Base	High Load	High Spin Avail	+Flow-gate Relief	Re-duced Wind	Base	High Load	High Spin Avail	+Flow-gate Relief	Re-duced Wind
ENT	1	1	0	0	0	0	0	30%	27%	33%	17%	23%
FRCC	0	0	0	0	0	0	0					
MAPP_US	32	32	4	3	3	2	3	12%	10%	11%	6%	10%
MISO_IN	28	28	1	0	0	1	1	2%	2%	2%	2%	2%
MISO_MI	24	24	0	0	0	0	0	0%	0%	0%	0%	0%
MISO_MO-IL	32	24	8	8	8	5	5	26%	24%	25%	15%	21%
MISO_W	261	196	65	61	62	57	26	25%	23%	24%	22%	13%
MISO_WUMS	9	9	0	0	0	0	0	1%	0%	0%	0%	0%
NE	55	34	22	21	21	19	9	40%	38%	37%	33%	26%
NEISO	18	18	0	0	0	0	0	2%	1%	1%	1%	2%
NonRTO_Midwest	0	0	0	0	0	0	0					
NYISO_A-F	19	19	1	1	1	1	1	5%	4%	4%	4%	5%
NYISO_G-I	1	1	0	0	0	0	0	0%	0%	0%	0%	0%
NYISO_J-K	0	0	0	0	0	0	0					
PJM_E	6	6	0	0	0	0	0	1%	0%	0%	0%	1%
PJM_ROM	6	6	0	0	0	0	0	0%	0%	0%	0%	0%
PJM_ROR	44	44	1	0	0	0	0	1%	1%	1%	1%	1%
SOCO	0	0	0	0	0	0	0					
SPP_N	146	124	21	18	17	14	12	15%	12%	12%	10%	10%
SPP_S	148	148	5	5	5	10	4	3%	3%	4%	7%	2%
TVA	0	0	0	0	0	0	0	0%	0%	0%	0%	0%
VACAR	9	9	0	0	0	0	0	0%	0%	0%	0%	0%
IESO	17	17	2	1	1	1	2	13%	8%	6%	6%	12%
MAPP_CA	1	1	0	0	0	0	0	0%	0%	0%	0%	0%
EI	859	742	131	119	120	110	64	15%	14%	14%	13%	9%

Reviewing the results for the five key wind regions in the analysis provides additional insights. Table 6-5 below shows the results for the key wind regions, defined as regions with over 30 TWhs of wind potential and >=10% wind curtailment in the Scenario 1: CP Base case. The results for the key regions drive, and hence, mirror the overall results. The results demonstrate the impacts of both the transmission changes (Flowgate Relief) and the generation changes (Reduced Wind).

As seen in Table 6-5 below, of the 10 TWhs of additional flowgate relief, 10 TWhs come from the three regions where the flowgates were relaxed and an additional 5 TWhs of additional wind generation come from regions close to those three, Nebraska and SPP_ North. Interestingly, SPP_South, which had very little wind curtailment in the base case (5 TWhs out of 148 TWhs of potential) had increased wind curtailment in the Flowgate Relief sensitivity, increasing from 5 TWhs to 10 TWhs of curtailment. This may suggest that the additional “transmission” in the case allowed power to flow into other areas but encountered constraints in SPP_South.

In the Reduced Wind case, wind generation in four of the largest wind producing regions in the EI were reduced significantly, with reductions ranging from 15% to 40%. These regions were the MISO_W, Nebraska, SPP_N and MISO_MO-IL. These reductions produced the anticipated result of significant reductions in wind curtailment. In the MISO MO-IL and SPP N regions the wind curtailment was reduced 5 percentage points, while in the Nebraska and MISO W regions curtailment was reduced by 14 and 12 percentage points, respectively.

Table 6-5. Scenario 1: CP Sensitivity Results for Key Regions

	Potential Wind (TWh)		Curtailment (TWh)					Curtailment (%)				
Key Regions*	Base & Others	Reduced Wind	Base	High Load	High Spin Availability	+Flow Gate Relief	Reduced Wind	Base	High Load	High Spin Availability	+Flow Gate Relief	Reduced Wind
MAPP US*	32	32	4	3	3	2	3	12%	10%	11%	6%	10%
MISO MO-IL*	32	24	8	8	8	5	5	26%	24%	25%	15%	21%
MISO W*	261	196	65	61	62	57	26	25%	23%	24%	22%	13%
NE*	55	34	22	22	21	19	9	40%	38%	37%	33%	26%
SPP N*	146	124	21	18	17	14	12	15%	12%	12%	10%	10%
Total EI	849	742	131	119	120	110	64	15%	14%	14%	13%	8%
Key Regions Total	526	410	120	112	111	97	55	23%	21%	21%	18%	10%
All Others	323	332	11	7	9	13	9	3%	2%	3%	4%	3%
*Defined as over 30 TWh of Potential Wind and over 10% curtailment in the Base Case								Regions with Reduced Wind Potential				
								Regions with Flowgate Relief				

The observation that congestion may have shifted locations rather than being totally eliminated is further borne out by looking at the binding hours and congestion costs for the 25 flowgates that were modified and the regions around them. As Table 6-6 shows below, the total binding hours decrease by 22,559 for the 25 flowgates, but only 10,568 for flowgates in or between the 3 NEEM regions (inclusive of the 25). Thus, the "surrounding flowgates" excluding the 25 are binding about 11,000 more hours than before, and thus are absorbing about half of the reduction in binding hours on the 25. This result continues as you look at all flowgates in or between the three NEEM regions. The total decrease for the 239 flowgates (inclusive of the 25) is 10,568 hours rather than 22,559 for just the 25 flowgates. A similar result occurs when the congestion costs are considered, although the increased congestion costs in the remaining flowgates do not increase as much as the number of binding hours. In the binding hours, over 50% of the decrease for the 25 adjusted flowgates is offset by other flowgate increases in binding hours. With the dollars, only 37% of the dollars saved with the 25 flowgates are offset by increased costs on other flowgates.

Table 6-6. Flowgate Relief Sensitivity Impact on Transmission Congestion

		Number of Binding Hours			Congestion Costs ($000)*		
	Number of Flowgates Assessed	High Spin Availability Sensitivity	Flowgate Relief Sensitivity	Decrease	High Spin Availability Sensitivity	Flowgate Relief Sensitivity	Decrease
25 Modifed Flowgates in 3 NEEM Regions	25	23,404	845	22,559	6,724	75	6,649
All Flowgates in 3 NEEM Regions	144	37,486	21,966	15,520	7,966	2,278	5,687
All Flowgates in or between the 3 NEEM Regions	239	45,408	34,840	10,568	8,040	3,879	4,161
		High Spin Availability Sensitivity	Flowgate Relief Sensitivity	Change			
Net MISO Flows and SPP Flows into PJM ROR (TWh)		121	121	0			
*Average Shadow Price when Binding * Number of Binding Hours, summed across flowgates. Congestion figures are for the forward direction.							

We cannot, however, compare the relative sizes of the impacts from Flowgate Relief and Reduced Wind, however, because the relative changes in the inputs that were made are not comparable. Although the Flowgate Relief sensitivity increased flows on the affected elements by 50%, only seven transmission elements in three regions were adjusted. These elements are shown above in Table 6-2, along with their locations. Four of the seven elements are in the

MISO_MO_IL region and represent 63% of the total flowgate relief. The MISO_W flowgate represents 25% of the flowgate relief and MAPP_US represents 12%.

The transmission system included in the GE MAPS runs was developed using only reliability criteria. The Flowgate Relief results indicate that additional iteration and analysis might identify congestion relief/economic transmission projects that would be cost-effective. This additional analysis would have to include additional reliability analysis as well as economic evaluation.

In summary, the overall Scenario 1: CP base run results, together with the sensitivity results, suggest that there are still issues in both reducing wind curtailments and meeting the CO2 targets in the scenario and that adjusting generation and/or transmission would be necessary to meet the target. Which choice (adjusting generation or transmission) is the most effective cannot be ascertained without additional analysis.

6.1.2 Scenario 3: BAU Sensitivity Results – High Gas Prices and High Load

The results of the sensitivity analyses on Scenario 3: BAU: Business as Usual, are shown below:

Table 6-7. Scenario 3: BAU: Business As Usual – Sensitivity Results

	Production Costs ($2010 Millions)			Change from the Base (%)	
	S3 Base	S3 Hi Gas	S3 Hi Load	S3 Hi Gas	S3 Hi Load
Fuel	$ 85,057	$ 94,326	$ 93,317	11%	10%
Variable O&M	$ 18,411	$ 19,072	$ 19,407	4%	5%
Total	$ 103,469	$ 113,398	$ 112,724	10%	9%
CO2	$ 154	$ 150	$ 178	-3%	16%
Total w/ CO2	$ 103,623	$ 113,548	$ 112,902	10%	9%
	Emissions (short tons)			Change from the Base (%)	
	S3 Base	S3 Hi Gas	S3 Hi Load	S3 Hi Gas	S3 Hi Load
NOx (000)	1,122	1,171	1,184	4%	6%
SO2 (000)	1,771	1,988	1,880	12%	6%
CO2 (millions)	1,792	1,833	1,889	2%	5%

The two sensitivities applied to Scenario 3: BAU involved increasing load and gas prices. Increasing gas prices by 25% in all seasons reduced the use of combined cycle plants and increased the use of coal. This resulted in production costs increasing by 10% overall and increased emissions from 2%-12%, depending on the emission type. Increasing load by 5% increased the use of combined cycle plants and, to a lesser extent, combustion turbines and coal. This resulted in increased production costs of 9% overall, and increased emissions in the 5-6% range.

6.1.3 Sensitivity Results - Demand Response in Southeast

Demand Response in the Southeast was addressed by making transmission adjustments in all six sensitivity models. These transmission adjustments were not included in the Base model runs. Scenario 1: CP: Combined Policies was of greatest concern because of the significant amount of

Demand Response called on across the Eastern Interconnection and the amount that occurred in three southeastern regions, VACAR, SOCO and FRCC. These three regions account for almost 80% of the total DR in the Eastern Interconnection. The top 6 regions account for over 90% of the total Demand Response called on in the Eastern Interconnection.

The changes made in the model included:

1. Splitting the double-circuited McIntosh – Purrysburg 230kV in South Carolina into two separate lines rated at 956 MVA a piece.
2. Removing four "McIntosh – W. McIntosh" flowgates.

The elements impacted are:

1. 382182 6R_WMCINTSH2 230 389001 6MCINTOSH 230 1
2. 381424 6W MCINTOSH2 230 382182 6R_WMCINTSH2 230 1
3. 381421 6W MCINTOSH1 230 382181 6R_WMCINTSH1 230 1
4. 382181 6R_WMCINTSH1 230 389001 6MCINTOSH 230 1

It was expected that these changes would reduce both the use of Demand Response and the high Locational Marginal prices in the southeast. Tables 6-8 and 6-9 show the amount of Demand Response in the southeast regions for each of the four Scenario 1: CP sensitivities.

Table 6-8. Scenario 1: CP Sensitivities –Demand Response Impacts

	Demand Response MWh				
NEEM Region	Scenario 1 Base	High Load	High Spin Availability	Flowgate Relief	Reduced Wind
VACAR	1,968,139	2,233,465	1,963,344	1,971,158	1,219,846
SOCO	674,892	944,310	601,954	603,150	390,910
FRCC	163,977	432,085	153,681	157,187	295,199
PJM ROR	147,133	459,421	82,612	85,813	150,530
MISO MO-IL	138,388	196,120	410,372	66,406	91,479
MAPP US	119,179	172,782	141,080	156,544	150,303
	Number of Hours Demand Response Used				
NEEM Region	Scenario 1 Base	High Load	High Spin Availability	Flowgate Relief	Reduced Wind
VACAR	1,367	1,478	1,481	1,470	1,017
SOCO	376	457	333	339	258
FRCC	683	1,359	697	720	1,065
PJM ROR	92	195	53	52	84
MISO MO-IL	573	762	1,748	333	387
MAPP US	2,527	3,346	3,139	3,499	3,196
	Demand Response - Maximum MW				
NEEM Region	Scenario 1 Base	High Load	High Spin Availability	Flowgate Relief	Reduced Wind
VACAR	7,983	10,695	7,245	7,245	6,372
SOCO	4,473	7,464	4,913	4,930	4,473
FRCC	849	3,359	849	849	849
PJM ROR	5,829	10,488	4,606	4,606	4,767
MISO MO-IL	993	1,569	785	690	970
MAPP US	188	256	182	196	186

The High Load sensitivity increased the use of demand response in all of the top six regions, in some cases dramatically. In the High Spin Availability sensitivity overall MWh of demand response decline slightly in the southeast but increases in the Midwest, particularly in MISO MO-IL, where the many of the top congested flowgates are located. The number of hours DR is used and the maximum MW in the High Spin Availability provide a more mixed message with some regions increasing and some decreasing. The Flowgate Relief sensitivity increased the use of demand response slightly in VACAR and somewhat in MAPP US. It decreased the use of demand response slightly in the other regions. Overall, the PJM ROR region benefits from the High Spin Availability and Flowgate Relief sensitivities, with all metrics showing decreases, some significant. The Reduced Wind sensitivity has mixed results with decreases in VACAR and SOCO in the southeast while FRCC's use of DR increased significantly. In the Midwest, PJM used essentially the same amount of DR as in the base case, while MISO_MO-IL decreased and MAPP US increased.

Table 6-9. Scenario 3: BAU Sensitivities: Demand Response Impacts

	Demand Response MWh		
NEEM Region	**Scenario 3 Base**	**High Load**	**High Gas**
SOCO	583,316	1,071,971	481,453
VACAR	214,987	219,676	93,286
SPP S	81,279	175,427	96,697
FRCC	48,175	253,072	94,431
	Number of Hours Demand Response Used		
NEEM Region	**Scenario 3 Base**	**High Load**	**High Gas**
SOCO	340	536	311
VACAR	317	364	217
SPP S	206	369	219
FRCC	111	290	145
	Demand Response - Maximum MW		
NEEM Region	**Scenario 3 Base**	**High Load**	**High Gas**
SOCO	5,453	7,231	5,756
VACAR	2,285	2,960	1,977
SPP S	1,025	1,669	1,088
FRCC	1,413	4,269	2,554

The Scenario 3: BAU High Load sensitivity shows increases in all metrics for all four regions, with some increases being significant. The High Gas sensitivity has more mixed results, generally with decreases in the SOCO and VACAR regions and increases in the use of DR in the SPP S and FRCC regions.

When more than one change is made in a model, the impact of individual changes cannot be identified. Even with the transmission changes in the sensitivity runs the southeast is still using a significant amount of Demand Response.

6.1.4 Sensitivity Results - Southeast Price Impacts

Tables 6-10 and 6-11 show the results of the sensitivity runs on Locational Marginal prices in the SOCO, VACAR and FRCC regions.

Table 6-10. Scenario 1: CP Sensitivities: Locational Marginal Price Impacts in Southeast

	Load-Weighted Average Annual LMPs ($/MWh)				
Region	Scenario 1 Base	High Load	High Spin Availability	Flowgate Relief	Reduced Wind
SOCO	$ 99.98	$ 110.45	$ 114.91	$ 114.63	$ 101.08
VACAR	$ 112.49	$ 123.17	$ 128.99	$ 129.28	$ 107.76
FRCC	$ 80.05	$ 85.52	$ 98.98	$ 98.87	$ 82.87

Table 6-11. Scenario 3: BAU Sensitivities: Locational Marginal Price Impacts in Southeast

	Load-Weighted Average Annual LMPs ($/MWh)		
Region	Scenario 3 Base	High Load	High Gas
SOCO	$ 70.41	$ 85.66	$ 77.34
VACAR	$ 61.75	$ 65.58	$ 64.62
FRCC	$ 67.74	$ 77.02	$ 80.83

In all instances except one (Scenario 1: CP: Reduced Wind in VACAR) LMPs increase in the sensitivities. If the transmission fixes are reducing the LMPs, that reduction is being more than offset by the other changes in the model.

As with other aspects of the project, in a more detailed transmission analysis this issue would receive additional iterations and analysis, including analyzing a variety of transmission and generation options until the LMPs were reduced to an acceptable level. Because of the strategic nature of this effort and time and resource constraints, this additional analysis did not occur.

7 Observation and Guidance

The EIPC stakeholder process has been the first of its kind to involve such a wide breadth of stakeholders from across the Eastern Interconnection. The DOE anticipated a number of benefits from this unprecedented stakeholder effort, including a broader awareness by stakeholders of the need for key transmission facilities and information and tools to facilitate the development of new transmission facilities needed to meet potential future resource and system conditions. The guidelines outlined by the DOE FOA called for the analyses and planning to be conducted in "a transparent and collaborative manner," open to participation by a wide range of interested stakeholders. The FOA outlined the establishment of a multi-constituency steering group, at least one-third of which should be state officials. The FOA also required that funds be made available for travel costs and other expenditures to facilitate the participation of certain key stakeholder sectors (*i.e.*, end-use consumers and non-governmental organizations). Finally, the FOA stated that the PIs "demonstrate (and develop if necessary), a process for reaching decisions and consensus."[5]

The EIPC SOPO and the governing charter of the SSC also reflected these principles. The values that the Steering Committee embedded in its Charter consisted of inclusion of multiple viewpoints and interests, balance of both regional and sector representation, and transparency of meetings and decisions. Importantly, the SSC charter also adopted the idea of reaching decisions by consensus, and it was this requirement which many participants cited as a key element in the progress that the SSC made. More information on stakeholders' observations and guidance can be found at http://www.eipconline.com/Phase_II_SSC_Meetings.html. The information can be found under the December 4-5, 2012 SSC Meeting section.

The EIPC's objectives included the following:

1. Creating a single working power flow model ("Roll-up") and analysis of approved regional plans throughout the Eastern Interconnection (which includes 39 states, the District of Columbia, and large portions of Canada);
2. Development of future interregional expansion scenarios to be studied; and
3. Development of detailed generation expansion, and interregional transmission expansion, to reliably accomplish the policy goals of three future interregional expansion scenarios.

Stakeholders agreed that these objectives were met and were pleased with the results that came from the process while recognizing the limitations of the results.

Phase 1 of the project involved the development of eight distinct futures and 72 additional sensitivities, a solved power flow case with stakeholder specified generation and transmission additions and macroeconomic and resource analysis for all futures and sensitivities. Phase 1 concluded with the SSC choosing three scenarios for more detailed transmission and production cost analysis in Phase 2.

[5] U.S. DOE & NETL, Funding Opportunity Number: DE-FOA0000068, Issued July 2009, pp. 6, 7 and 10.

Following the completion of Phase 1 of the project, some initial observations were drawn including the following:

- This project represents a unique dialogue with many different stakeholder groups on public policy and interconnection-wide transmission analyses to increase understanding of alternative policy futures and the generation and transmission that might be needed to support them. It does not require one size fits all projects or solutions, nor does it make any conclusions regarding market driven versus vertically integrated utility models. It does, however, show potential ways to accommodate differing stakeholder-chosen policy futures. The EIPC analysis will continue to be a valuable contributor to both the utility and the regulatory functions in their efforts to efficiently advance the electricity industry.
- Although previous experience of the participants has been in transmission planning exercises that are generally more limited in geographic scope and that involve fewer participants than the analyses conducted by EIPC, the Topic A project work involving a larger team, over the full Eastern Interconnection, proceeded well.
- The interaction between Topic A and Topic B participants also developed a communication capability that will serve the nation well in the future.
- It is expected that the participants will use the experience for continuing and enhancing future coordination efforts and that all of these efforts will help guide the U.S. in considering and establishing potential national goals for energy.

7.1 General Observations

Phase 2 continued the open and productive dialogue between the EIPC, EISPC and stakeholders. Because of the nature of the work in Phase 2, the discussions were focused on traditional transmission planning and production cost analysis and were more technical in nature. General observations from Phase 2 include:

- The goal of the DOE's Funding Opportunity Announcement, "to prepare analyses of transmission requirements under a broad range of alternative futures…" has been met. The project is not intended to supplant existing regional planning processes.
- The project was very helpful in understanding the complexity of interconnection-wide transmission planning.
- The futures developed represent significantly different policy drivers and the project has provided a great deal of information on these three scenarios.
- The results of Phase 2 serve as indicative transmission build-outs that present options that could be considered as part of a more traditional planning process that involves analyzing more model years, considering all NERC mandatory compliance criteria and evaluating the economic benefits of specific transmission projects or groups of projects as resource plans become more certain.
- Transmission reinforcements presented in this report are not an absolute indication of the required transmission reinforcements since the scope of this project was limited to evaluate specified alternatives and considered only higher voltage level additions and

constraints and did not consider all mandatory NERC planning requirements. In addition, necessary simplifying assumptions used for this analysis regarding the choices of how transmission facilities are configured, the impact of fuel supply variations on resource availability, and other factors would be taken into account in the final determination of required transmission reinforcements.

- The interrelationships of various energy related infrastructures may need to be considered further to better understand how these relationships might impact the broad range of alternative futures. One example is the relationship between the natural gas supply and delivery infrastructure and the electric transmission system highlighted in Phase 1 of the project.
- Much more detailed analysis, iteration and optimization than was possible in the project would be needed to develop actual detailed transmission plans.

7.2 Phase 1 and Phase 2 Process Observations

In the last quarter of 2012, The Keystone Center, the facilitator of the EIPC stakeholder process, conducted a number of interviews with various members of the stakeholder process and EIPC Planning Authorities (PAs) to gather input about whether the goals of the project were met. The following observations are the synthesis of these interviews and cover the entirety of the stakeholder process, both Phase 1 and Phase 2.

Overwhelmingly, stakeholders found the overall process to be very worthwhile and they are were pleased to have participated. Stakeholders generally agreed that the EIPC process provided great value and elements of EIPC should continue in the future. Specifically, stakeholders mentioned the importance of broad and consistent stakeholder input in the development of planning scenarios, the importance of looking at long-term planning horizons and policy drivers, and the value of the EI-wide roll-up process, particularly in better understanding the various planning efforts undertaken across the interconnection. Stakeholders in general developed more trust of the PAs' process and over time relied more heavily on their input and judgment. Ultimately, stakeholders saw particular value in:

- The openness, inclusiveness and transparency of the process
- The opportunity to learn more about transmission planning and have input into the process
- The structure and balance of the SSC
- The independence of the Chair, Vice-Chair and facilitators
- The willingness and ability of the chairs to develop straw proposals when the group faced difficult or contentious issues
- The relationships and understanding that developed over time
- The working groups' ability to delve into the details and make recommendations to the SSC
- The access to data and information on the web site

- The DOE requirement to come to consensus; at first, stakeholders were concerned about this requirement but believed it ultimately led to a better understanding of others' positions and more creative ideas to achieve consensus.

Stakeholders also identified the following challenges/opportunities:

- Understanding the transmission planning process and the models used
- The inability to iterate the analysis more frequently; *i.e.*, to review the results from a smaller set of analysis before determining next steps
- More time was needed to consider the results of the analyses and the voluminous data generated

The stakeholder balance designed into the SSC structure did not always materialize in the process.

7.2.1 Stakeholder Structure

The EIPC stakeholders were organized into various groupings and entities. The Stakeholder Steering Committee (SSC) was the decision-making body of the stakeholder process. The SSC members were elected by the Sector Caucuses, which were themselves elected through a transparent selection process. These two bodies - the SSC and the eight Sector Caucuses comprised the publicly elected representatives (see below for region and sector balance in the Sector Caucus selection process) in the DOE project.

The structure of the SSC was based in large part on existing Planning Authority stakeholder interest group membership, with adjustments based on input from stakeholders. The result was a 29-member body, with representation from eight interest groups, or Sectors, as outlined below. As specified in the DOE FOA, the states held one-third (ten) of the 29 SSC seats. Figure 6-1 depicts the Stakeholder Steering Committee structure.

The process for selecting first the Sector Caucus and then SSC members was designed to achieve both transparency and inclusiveness. Eligibility requirements were established and posted, candidates were required to register online for the sake of transparency, and stakeholders were then notified about how voting would take place – either through meetings with phone-in access or through an online voting system. Objections or anomalies in the process could be submitted to The Keystone Center and the Executive Director of EIPC for arbitration.

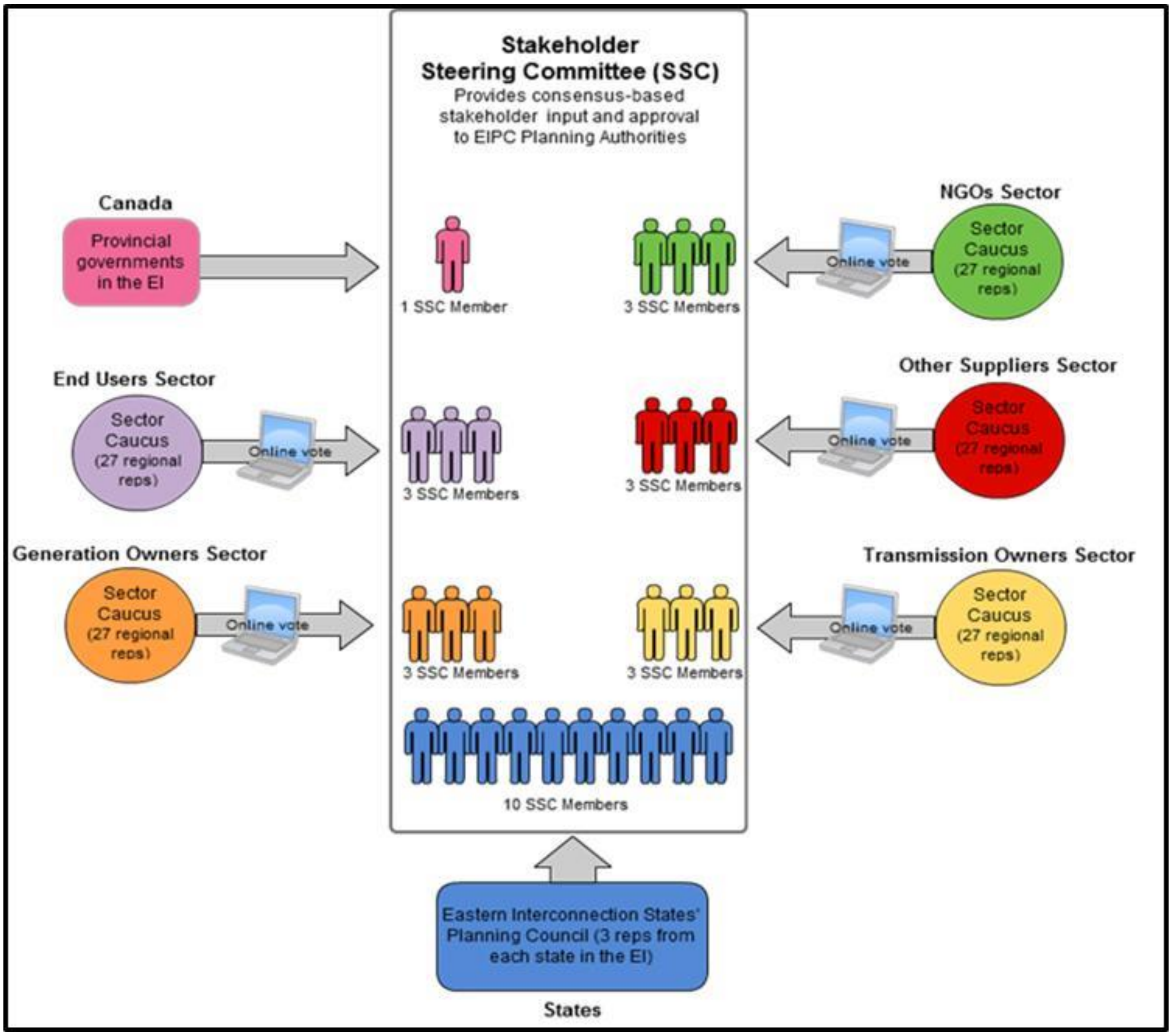


Figure 7-1. Stakeholder Steering Committee Organizational Structure

Some flexibility was allowed. The Non-Governmental Organization (NGO) and End User sectors were allowed to select Caucus members from across the interconnection because they argued their interests were not as closely aligned with regional differences as those in other sectors.

- Stakeholders thought it was useful to have the transparency and the inclusiveness afforded by these procedures. In contrast, some sectors felt that the regional balance needed to be more strictly observed in the SSC. For the TO /TD sector, for example, it was important to have a geographically-balanced set of representatives from across the Eastern Interconnection at each meeting, which was accommodated by their proposal to allow Sectors to appoint ten Table Representatives, who would be seated with the SSC members at meetings.

- The Table Representatives were members of the Sector Caucuses or other experts designated by their Sectors who could assist SSC members with their decision making. Stakeholders requested that the Table Representatives be present at SSC meetings and seated near SSC members to provide input on issues discussed. The Table Representatives did not go through the same selection process as the SSC or Caucus members, but rather each sector was allowed choose to use their Table Representatives as needed. Over the course of the project, many of the Sector Caucus members and Table Representatives served a consultative role for the SSC members when making decisions, and time was provided at the stakeholders' request at each SSC meeting for this consultation.

- Several participants said that the ten-week process to finalize the rules of governance seemed lengthy at the time, but this initial phase of agreeing on rules, responsibilities, and procedural expectations proved to be an important step in cultivating the environment that allowed and encouraged collaboration and consensus-building. Stakeholders suggested that the balance of regional and sector input be maintained in future efforts.

- The stakeholders interviewed observed that the structure and balance of the SSC was workable and fair in concept. Stakeholders mentioned a number of factors that were important in achieving this goal including, the transparency in the selection process, the geographic balance emphasized in the selection of caucus members, and reserving seats for certain interests. Although there was some early concern about the higher number of states' representatives on the SSC, most stakeholders interviewed ultimately agreed that the states played a key role in the negotiations and their greater level of representation was appropriate.

- However, several stakeholders interviewed mentioned that the balance built into the structure of the SSC did not always materialize in practice. Some Sectors did not have a strong and active caucus to support the SSC members and some SSC members were not as involved due to time constraints, lack of supporting resources, or waning interest. Almost inevitably, different regions and different sectors were better represented than others, particularly at the working group level.

- As prescribed in the DOE FOA, funding was provided for the travel expenses of a limited number of End User and NGO participants, which greatly bolstered active participation from those sectors, and allowed voices that are not as prominent at the sub-regional level. The participants from the NGO and End Users sectors who were interviewed felt that the funding they received made their effective participation possible. The independent Topic B funding for the state participation was also critical to the prominent role the states were able to play. The states were able to build a strong working relationship and develop recommendations and decisions through face-to-face EISPC meetings in advance of the SSC meeting.

- The creation of Work Groups was essential to completing the more detailed work, such as development of model inputs and understanding the analyses and results. The Work Group structure allowed each Sector to assign individuals with the expertise needed to understand and interpret detailed technical information,, sort through disagreements, and make consensus recommendations to the SSC wherever possible. The Modeling Work Group (MWG) members in particular gained the trust needed so that the SSC members could rely on their judgment or consult with them in advance of making decisions.

7.2.2 Transparency & Communication

To achieve the goal of inclusiveness and transparency, every meeting and webinar held by the SSC and its appointed Work Group members was open to the public. Webinar or phone access was provided for those who could not attend meetings in person and audio-visual recordings of the webinars and written summaries were made available. Perhaps the most useful tool aiding record keeping and information sharing in both Phase 1 and Phase 2 was the EIPC project website (www.eipconline.com). This site was open to the public and served as a repository for event information; meeting agendas, summaries and materials; working documents being used by stakeholders in various project tasks; modeling results and data; project reports; and other materials supporting stakeholder participation and decision making. In addition, e-mail listservs were employed to keep stakeholders up to date and alert them to the release of important documents and information.

- Many stakeholders noted that the website was critical to their ability to stay informed and engaged. Throughout Phase 1, most stakeholders agreed that the use of the website, listservs to distribute critical information, and requirements to provide all l information requiring a decision at least one week in advance of the SSC meetings created a satisfactory level of communication and transparency between the PAs, CRA and the stakeholders and helped create greater trust of and credibility in the analysis.

- Stakeholders within each sector were responsible for ensuring that their Work Group, Sector Caucus and SSC members were communicating among themselves and staying informed enough to participate effectively. Some sectors' communication and information-sharing efforts were more successful than others', largely due to uneven access to the funding, time, and availability of support staff needed to perform these functions.

- In Phase 2, some stakeholders, mostly SSC members, noted that the Transmissions Options Task Force (TOTF) process was less transparent and communication was more difficult. While the SSC members felt more disconnected during this phase, the TOTF members spoke more favorably about their access to information during meetings. CEII rules and regulations necessitated the observance of confidentiality rules at this juncture, but the PAs worked together to develop the transmission solutions to each Scenario and then presented the results to the TOTF. The PAs were clear that they would also evaluate any options presented by the TOTF members.

- Originally, it was thought that the use of CEII data in the TOTF's work would create another communication-related challenge. To deal with this, the PAs arranged for stakeholders who requested CEII clearance to obtain it. Ultimately, none of the important information needed to visualize or document the existing and proposed transmission lines for the Scenarios proved to be CEII and was freely shared with all stakeholders.

- While the stakeholders appreciated access to the extensive data generated during the life of the project, several noted that they needed more time to analyze and understand the information. Had the schedule allowed, the stakeholders agreed that the project would have benefited from sequenced decision-making, that is, using the information from early analyses to inform decisions about what additional analysis is needed.

- Several stakeholders stated that they would have benefited from more information on the different models used throughout the project. More education at the beginning of the project, on the models and their purposes, capabilities and inputs and outputs would have streamlined some of the discussions that occurred in later tasks.

Due to the unprecedented level of transparency and information-sharing in this project, stakeholders from all sectors acknowledged that one of the more important outcomes of the stakeholder process was the education of all parties about the complexity and differences of sub-regional transmission planning process and analyses, about how to consider policies and other factors in the transmission planning process, and about the perspective of other stakeholders who have not previously been actively engaged in transmission planning in every region.

7.2.3 Decision-Making

Despite considerable skepticism at the beginning, consensus decision-making proved to be a vital driver in building trust, reaching an understanding among stakeholders of the interests at stake, and creating workable solutions. A number of stakeholders initially expressed their concern that this approach would result in stalemate, but the design and structure of these decision-making efforts -- including the option of backstop voting, continuity in stakeholder participation, and the chair's and vice-chair's straw proposals for resolving differences, among other factors -- proved effective. Over time, consensus became the norm for Sector decision-making as well, even though EISPC and TO/TDs set up voting as the expected method for developing Sector-based positions.

The following factors contributed significantly to successful consensus-based decision making:

- *The DOE mandate to use consensus*: A number of stakeholders said that, had DOE not initially required that the stakeholder process be driven by consensus-based decision making, they never would have opted for such an approach, due to the perceived difficulty it would pose. In the end, nearly every decision was successfully achieved through the consensus of the SSC.

- *Backstop voting rules developed by the stakeholders*: The stakeholders included in their charter a backstop voting rule, which was intended as an option of last resort if consensus could not be reached. This rule included a high threshold for its invocation, and a key provision of this rule prevented any one sector, including the states with ten voting members, from unilaterally blocking a particular proposal or decision. Though this backstop voting process was never actually utilized, its establishment at the beginning of the stakeholder process gave stakeholders some confidence that they would be able to avoid stalemate.

- *Face-to-face meetings to facilitate trust building and negotiation*: One of the factors that enabled stakeholders to successfully reach consensus on all issues was their participation in multiple face-to-face meetings over the course of the project. This periodic in-person work, combined with the opportunities these events provided for informal communication and relationship-building, eventually led to greater trust, more effective negotiations, and stronger work products. In contrast, decisions that had to be handled using a webinar platform were perceived as more difficult because they did not allow for SSC members to consult in real-time with each other or their Sector Caucus.

- *Work Groups*: Nearly all stakeholders described the various work groups as invaluable to their decision making. Every project task involving stakeholders had one or more associated work groups with at least one member from each sector and participation from additional experts. This enabled the stakeholders' decisions to be informed by technical and subject matter experts as well as all sectors' perspectives, while streamlining the SSC's decision-making processes.

- *Role of the Chairs* – The SSC's Chair and Vice-Chair were widely viewed as indispensable to the SSC's decision making. In particular, stakeholders appreciated the chairs' ability to devise straw proposals for the SSC to consider when contentious or complex issues arose. These proposals often clarified options and their pros and cons, enabling the SSC to more easily understand the choices they faced and determine an optimal path forward. The Chairs, by virtue of their election by the SSC members, were viewed as spokespersons for the broader interests of the SSC, experts on the topics under deliberation, and could provide proposed solutions for consideration. They also played an important shuttle diplomacy role during negotiations among the sectors.

- *Independence of SSC Chairs and facilitators.* Initially there were some concerns about the ability of the Chairs and facilitators to be independent. Ultimately, stakeholders felt that independence was achieved and the Chairs and facilitators were committed to a fair and open process, not a particular result. Many stakeholders credited The Keystone Center with helping to design, implement and facilitate the successful aspects of the decision making process. Many stakeholders thought a neutral facilitator who could serve as a "keeper of the process" was critical to the project's success.

One of the concerns stakeholders noted was the unevenness in stakeholder sector resources, which skewed stakeholder participation, and, by extension, the outcomes of their deliberations. Predictably, sectors with more resources were able to participate more fully, and to advocate their interests more effectively. Those sectors with strong Sector Caucus and Work Group representation had much greater influence over the development of options that were ultimately considered by the SSC. Therefore, while the process was designed to maximize opportunities for stakeholders to engage in decision making, some were better-equipped than others to take advantage of those opportunities, which resulted in some stakeholder interests being well-represented, and others less so.

7.2.4 Process Conclusions: Adapting the Stakeholder Experience to Future EI-wide Transmission Planning Efforts

Based on the stakeholder interviews and observations from The Keystone Center, a number of recommendations emerged about how the stakeholder process might translate to similar efforts in the future:

- Stakeholders across the board agreed that the overall EIPC process employed for the DOE Project provided great value and elements should continue in the future. Specifically, stakeholders mentioned the importance of broad and consistent stakeholder input in the development of planning scenarios, the importance of looking at long-term planning horizons and policy drivers, and the value of the EI-wide roll-up process, particularly in in terms of better understanding, and gaining knowledge of, the various planning activities undertaken across the interconnection. Stakeholders observed that the relationships developed were very important and it would be helpful to maintain them going forward.

- States and PAs in particular developed a strong working relationship as a result of this project, including greater understanding of the states' interests and better understanding of the various sub-regional planning processes. Stakeholders in general developed more trust of the PAs' process and over time relied more heavily on their input and judgment.

- Stakeholders found that the <u>process</u> of building consensus helped reach a deeper understanding of the concerns of sectors and individual stakeholders, helped generate creative solutions to issues where disagreement emerged, and was the basis for developing trust both within and across sectors.

- As noted above, the SSC chairs were considered vital to the consensus decision-making process. Selection of the chairs by the stakeholders was important to establishing their credibility with all the sectors. It is also important for the chairs to maintain objectivity throughout the process and in the development of proposed decision options.

- The facilitators also played an important role by helping design the stakeholder structure, the selection of Sector Caucus and SSC members, and the governing charter. The facilitators were responsible for ensuring that the rules of governance were followed throughout the project with the objective to create a transparent environment open to fair consideration of all interests.

- It would be advisable to restructure the stakeholder input in the future to accommodate a more iterative analysis. Stakeholders felt they would have learned much from the early analysis and as a result would have made different choices if they had not had to make all decisions upfront. Throughout the analyses, stakeholders frequently asked for more flexibility in the schedule to allow for more time to make decisions about Scenarios, Sensitivities and model inputs that were informed by the prior modeling results. Unfortunately, due to schedule commitments within the SOPO this was not possible.

- Funding for key stakeholder sectors with travel constraints and more limited resources (states, NGOs, consumer advocates) was important for effective participation in this process.

- In future EI-wide analyses, the process could be structured to give the PAs a greater voice in the development of the planning scenarios while maintaining a robust collaborative process in which stakeholders' views are fully considered. Maintaining transparency throughout the process will be key to maintaining credibility with stakeholders. In this first effort, the PAs took a "hands-off" approach, allowing the SSC to describe and define the Scenarios and model inputs. For the first pass, that approach helped build trust and credibility for the PAs. Over time, the stakeholders asked for more input and advice from the PAs perhaps in recognition that the PAs had an interest in getting information that informs the sub-regional planning process, and could provide critical advice on certain elements of the Scenarios that are of particular interest.

- More interaction between the interconnection-wide efforts taking place in the east and the west could benefit the stakeholders as well as the analysts. During one of the final SSC meetings, the project director of the WECC-wide planning effort provided an overview of their activities and analysis. Sharing lessons learned and challenges with EIPC provided helpful insights, but came late in the process.

7.3 Analytical Observations and Guidance

In addition to process Observations and Guidance, there were also Observations and Guidance on the analytical process undertaken. These are listed below:

- The transmission option analysis presented here represents a single snapshot in time for each of three very different scenarios. It focuses on a snapshot of a specific year – 2030. Traditional transmission planning analyzes interim years typically utilizing models for one, five, and ten years out rather than "jumping" out twenty years. The results of this transmission analysis might be very different if it were done in a more incremental fashion. Future studies may wish to look at smaller time intervals – *e.g.*, 5, 10 and 15 years.

- There are many ways to implement a given policy initiative and different forms of implementation may require different generation and transmission.

- The cost estimates in the project are based on a variety of generalized assumptions and are only broadly indicative on a relative basis between the futures. A number of potentially significant costs were not included and some costs may be reduced through additional analysis.

- Future interconnection-wide studies analyzing wind integration may wish to consider other load blocks in addition to the peak load and less-than-peak load blocks that were studied in EIPC's power flow modeling if substantial resource curtailment occurs during other load block periods.

- Future interconnection-wide studies may wish to consider a more iterative process, allowing for opportunities to review the analysis results before making decisions on the next part of the analysis. For example, future interconnection-wide studies may wish to dedicate sensitivities to iterate between the production cost model and the powerflow model to assess intra- and inter-regional transmission capacity as well as alternative generation location.

- Many PAs are already doing transmission expansion planning that considers economic criteria in addition to reliability criteria. Future interconnection-wide transmission planning exercises should consider doing so as well.

7.4 SSC Overall Observations and Guidance

At the final SSC meeting of the project, the Chairs proposed and the SSC adopted, with revisions, a document outlining their observations and guidance for the use of the report. The revised memo is included in its entirety below.

> "The Stakeholder Steering Committee (SSC) for the first Eastern Interconnection Planning Collaborative project has been responsible for providing oversight and direction for the project studies performed by the EIPC PAs (PAs) and their consultants. The SSC believes that it has meet this responsibility effectively and is very pleased that the diverse group of stakeholders comprising the SSC has been able to reach agreement on all of the issues before it. The SSC is also pleased with the working relationship between the SSC and the PAs that developed over the course of the project.
>
> The SSC believes that the overall process employed for managing and conducting the project provided great value, and elements of that process should be continued in future interconnection-wide planning efforts. Specifically, broad and consistent stakeholder involvement, including input into the scenarios to be studied and the analyses undertaken was important. In addition, the interconnection-wide roll-up process provided valuable information on the planning activities and process undertaken across the interconnection, and how regional planning information may be reconciled and used productively in Interconnection-wide transmission planning efforts. In concluding it work, the SSC makes the following additional observations about the project, recognizing that each SSC sector, as well SSC individual members, may provide additional observations on the study process and results, but may not speak for the SSC.
>
> 1. The project is the first ever effort to perform a transmission planning analysis on an eastern interconnection-wide basis. The objective of this project, as outlined by the FOA, is "to facilitate the development or strengthening of capabilities in [the Eastern Interconnection]… to prepare analyses of transmission requirements under a broad range of alternative futures and develop long-term interconnection-wide transmission expansion plans." This goal has been met.
>
> 2. This project has been very helpful in understanding the complexity of interconnection-wide transmission planning and has provided a number of valuable lessons that should facilitate future efforts to integrate transmission plans developed on a regional basis and to study and identify multi-regional transmission additions needed to support future potential policy requirements on reliable and economic basis.
>
> 3. The three futures analyzed in this effort were developed by a broad cross section of stakeholders from the Eastern Interconnection. These futures have significantly different policy drivers - a national renewable energy standard implemented regionally, an economy-wide carbon emission reduction

requirement that is implemented primarily through carbon emission reductions in the electric utility sector, and a business as usual future that reflects current and likely environmental and renewable energy requirements. The project has provided a great deal of information on the significantly different generation and transmission additions and retirements that may be needed across the interconnection to meet the objectives of these possible futures.

4. It is very important to emphasize for those who read the project report, but were not involved in the process, that the work done provides a high level analysis of the potential generation and transmission needs for the defined futures, focusing on a snapshot of a specific year - 2030. It was not the purpose of the project to develop specific, detailed transmission and generation expansion plans. Such plans would require much more detailed analysis, iteration and optimization than was possible in the project. As a result, the project results should not be seen as identifying or recommending the retirement or construction of any specific generation or transmission. A true, utility grade transmission planning process, focused on meeting the policy objectives of the futures studied on an economic basis, while meeting all applicable reliability and regulatory requirements, could lead to materially different results.

5. It is also very important for readers of the final report to recognize that the cost estimates in the project report are based on a variety of generalized assumptions. This information is only broadly indicative on a relative basis between futures. The cost information is not complete in that economic optimization of alternative transmission and generation additions was not undertaken. Also, the work considered only the cost of improvements to the high voltage transmission system and not the underlying system. Nor were costs and benefits external to the electric utility industry considered. The estimated costs for each future studied could change in significant ways in more detailed studies that seek to economically optimize generation and transmission additions, including required improvements to lower voltage facilities, to meet policy goals on a reliable basis. For this reason, the cost numbers and comparisons in the report should not be relied upon without further study for the purpose of evaluating different policy choices.