EIPC

Eastern Interconnection Planning Collaborative

Phase 1 Report:

Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis

DOE Award Project
DE-OE0000343

December, 2011

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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.

Foreword

In mid-2009 the Department of Energy (DOE) issued a funding opportunity announcement (FOA), "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009 (ARRA). PJM Interconnection, LLC (PJM) was selected as the recipient of the Topic A portion of this FOA for the Eastern Interconnection and subsequently entered into a cooperative agreement with DOE's National Energy Technology Laboratory (NETL). The work of this funding opportunity is divided into two phases – Phase 1 and Phase 2. Phase 1 focuses on the formation of a very stakeholder group (Stakeholder Steering Committee) and its work to model public policy "Futures" through the use of macro-economic models. This first phase examines eight futures chosen by the stakeholder group. The final work in Phase 1 is for the stakeholder group to choose three Futures scenarios to pass onto Phase 2 of the project. PJM's award, DE-OE0000343, entitled Eastern Interconnection Planning Collaborative (EIPC) has reached the end of its first phase. This report describes the efforts and results of Phase 1 of Topic A of the Eastern Interconnection portion of the Interconnection-level Transmission Planning and Analysis (ITPA) program. The project's initial meeting was in July 2010 and was intended to facilitate the President's goals relating to clean electricity which cannot be achieved without an adequate electricity delivery system.

The report was prepared by eight members of the Eastern Interconnection Planning Collaborative (EIPC) who have contracted as Principal Investigators for this project. EIPC was formed in early 2009 and comprises 26 of the major eastern utilities.

This project has been carried out in close interaction with the Eastern Interconnection Topic B recipient of DE-FOA-0000068, the National Association of Regulatory Utility Commissions (NARUC), and their award, the Eastern Interconnection States Planning Council (EISPC). EISPC comprises regulatory representatives from the 39 states of the Eastern Interconnection, along with the District of Columbia, and the City of New Orleans. While the detailed report on the EISPC work will be published as a separate document, this report includes results provided to EIPC as required for use in the Topic A work scope. The work has also benefited from close interaction with a Stakeholder Steering Committee representing a wide range of interests. DOE is additionally supporting the ITPA program through work at selected national laboratories. The EIPC is grateful to DOE and to all the above participants for their contributions.

Phase 2 of this project will focus on conducting the transmission studies on the three scenarios. This work will include a number of studies regarding grid reliability as well as studying the various options for transmission expansion. This Phase 2 work will be conducted throughout 2012. Concurrent with EIPC's work, EISPC's studies and whitepapers work will continue during 2012 and into 2013 with anticipated completion of all studies and whitepapers by mid 2013. Reports on each study and whitepaper, along with any study deliverables, will be released to DOE, EIPC and stakeholders upon completion and approval by EISPC.

Phase 2 of this project is scheduled for completion by December 2012, following review of Phase 1 efforts and authorization by DOE to proceed to Phase 2.

A listing of acronyms used in this report is provided for the reader in Appendix 6.

This report on Phase 1 of the project is a requirement of the EIPC Planning authorities' funding agreement with DOE. EIPC has invited the SSC and EISPC to provide comments on the report. SSC members and EISPC have provided extensive comments and suggested numerous additions to the report. All comments may be found at http://eipconline.com/Resource_Library.html. Some of those comments and proposed additions have been accepted as pertinent to the EIPC's Phase 1 report.

Executive Summary

The North American electrical power grid has evolved in five separate systems: the Western, Texas, Eastern, Alaska, and Quebec Interconnections, which together serve more than 300 million people through 200,000 miles of high-voltage transmission lines. Of these five, the eastern interconnection in the United States covers the largest area, serves over 39 states with 70% of the U.S. population, has the largest number of utility companies, and contains six of the eight North American Electricity Reliability Corporation (NERC) regions.

Growth in electricity use and the facilities needed to generate and transmit electricity to consumers represent continuing planning challenges for electricity companies, even with the present economic slowdown and projections for expansion of energy efficiency and demand side load management. Across the United States, states and planning regions are taking action to ensure a reliable, cost-effective, and increasingly domestic energy supply to fuel the country's growth and chart a path toward energy independence. Pro-active, long-range planning is an essential component of these efforts. In early 2009 a group of Planning Coordinators[1] in the east formed the Eastern Interconnection Planning Collaborative (EIPC), with the goal of improving joint planning of interregional grid development. EIPC is the first planning collaboration ever undertaken for the eastern interconnection, and membership now totals 26 Planning Coordinators. *Many advantages are anticipated from EIPC, including support for the best interests of electricity consumers in the further expansion of reliable electricity supply while addressing environmental goals*.

Shortly after the formation of EIPC, the Department of Energy (DOE) released a funding opportunity announcement (FOA), "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009 (ARRA). The FOA's objective was to support development of grid capabilities in the interconnection by preparing analyses of transmission requirements under a range of alternative futures and develop interconnection-wide transmission expansion plans. The FOA also noted that robust transmission and distribution networks are essential, as a matter of national interest, to enable the development, integration, and delivery of new renewable and other low-carbon resources, and the use of low-carbon electricity to displace petroleum-based fuels from the transportation sector.

PJM Interconnection, LLC (PJM) submitted a proposal on behalf of EIPC for the Eastern Interconnection Topic A portion of the FOA. PJM was selected and entered into a cooperative agreement with DOE's National Energy Technology Laboratory (NETL) entitled the Eastern Interconnection Planning Collaborative, award number DE-OE0000343. A subgroup of nine EIPC members agreed to perform the work. At the same time DOE accepted proposals for

[1] Planning Coordinators (formerly known as Planning Authorities until re-designated in NERC Functional Model) include RTOs, government power authorities and electric utilities who have taken on the responsibility of coordinating, facilitating, integrating, and evaluating transmission facilities under the NERC Functional Model.

Topics A and B in the Western and Texas Interconnections, and a proposal from the National Association of Regulatory Utility Commissioners (NARUC) for the Eastern Interconnection Topic B work. NARUC's cooperative agreement is titled the Eastern Interconnection States Planning Council (EISPC). EISPC is comprised of the 39 States in the Eastern Electric Transmission Interconnection (Eastern Interconnection or EI) plus the District of Columbia and the City of New Orleans as well as the eight Midwestern and eastern Canadian Provinces.

Please note that 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 EISPC does not bind any State Regulator in any State proceeding.

The Topic A work scope comprises 12 tasks divided into two phases. In Phase 1, an early requirement was the formation of a Stakeholder Steering Committee (SSC) representing the states and a balanced selection from industry and interested party sectors that would provide guidance to EIPC. The SSC structure makes decisions by consensus.[2] State SSC members are a subset of EISPC, whose structure is also built around collaboration and consensus-style decision making.[3] EIPC then, for the first time, developed a combined grid model for the interconnection based on a roll-up of the members' expansion plans for the year 2020. The Planning Coordinators undertook a reliability analysis of the roll-up of the regional plans and found no significant reliability issues. Such a finding is noteworthy as it is indicative of the fact that the respective regional plans are not causing burdens that would manifest themselves as unsolved reliability violations elsewhere in the Eastern Interconnection. This model served as the basis for EISPC and the Stakeholder Steering Committee (SSC) to adopt as a Stakeholder Specified Infrastructure (SSI) Model incorporating an extended timeline to 2030 together with some revisions to future generation and transmission assets. EIPC chose Charles River Associates' Multi-Region National (MRN) macroeconomic model and the North American Electricity and Environment Model (NEEM) to develop information on eight futures with nine sensitivities per future, for a total of 80 model runs. The futures were designed to be significantly different from each other and accordingly had multiple differences in their input assumptions, constraints, and objectives. In contrast, the sensitivities were designed to comprise only one change to an input assumption from the base future to which it was associated. This approach allowed the stakeholders to attribute the difference in results to the single change in the input assumptions.

The MRN model is a macroeconomic model of the entire economy, and the NEEM model is a generation resource model that indicates the amounts, types and general locations of the most

[2] The SSC developed a back-up voting structure in the event consensus could not be reached.
[3] Although DOE's FOA and EISPC's structure strongly encourages consensus and, in fact almost always reaches consensus, EISPC also developed a "back up" voting structure that has operated effectively the few times it has been used.

efficient generation to meet the load growth and energy/environmental policy conditions specified by the model users. The SSC provided the inputs to the MRN and NEEM models.

The SSC created working groups to develop the eight futures with 72 sensitivities and to specify the detailed inputs for the MRN and NEEM models. The Scenario Planning Working Group (SPWG) worked in the fall/winter of 2010 to develop narrative descriptions of the eight futures and to determine what sensitivities would be studied. Below is a brief description of the eight futures.

Table 1: SSC Alternative Futures

Future Descriptions	
Future 1: Business as Usual	Continuation of existing conditions including load growth, existing Renewable Portfolio Standards (RPSs), and currently proposed environmental regulations.
Future 2: National Carbon Constraint – National Implementation	Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy.
Future 3: National Carbon Constraint – Regional Implementation	Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050; achieved by utilizing a regional implementation strategy.
Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid	Aggressive implementation of energy efficiency (EE), demand response (DR), distributed generation (DG) and smart grid technology resulting in decline in load from today's levels.
Future 5: National Renewable Portfolio Standard – National Implementation	Meet 30% of the nation's electricity requirements from renewable resources by 2030; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy.
Future 6: National Renewable Portfolio Standard – Regional Implementation	Meet 30% of the nation's electricity requirements from renewable resources by 2030; achieved by utilizing a regional implementation strategy.
Future 7: Nuclear Resurgence	Significant nuclear facilities developed in Eastern Interconnection.
Future 8: Combined Federal Climate and Energy Policy	Reduce economy-wide carbon emissions by 50% from 2005 levels in 2030 and 80% in 2050 combined with meeting 30% of the nation's electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, demand response, distributed generation, smart grid and other low-carbon technologies; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy.

In order to construct computer simulations for each of these futures, many assumptions and data inputs were studied, debated – often vigorously , and agreed upon by EISPC and the SSC.

Once all of the assumptions and inputs were determined, EIPC provided EISPC and the SSC with the opportunity to change one input at a time to run a "sensitivity" which would show the implications of that changed input on the entirety of that specific future. For example, if a future was modeled using a $4 natural gas price, a sensitivity on that future could be modeled changing just the natural gas price to a higher or lower price to see what impact it would have on the modeling results.

Sensitivities common to several futures included high and low load growth, and changes in natural gas prices. This combination of futures and sensitivities ensured that a very wide range of possibilities was considered in the evaluations leading to the three final scenarios to be studied in the Phase 2 of the project. The variation in future inputs and outputs from the model included:

- Additional hardened transfer capability needed between NEEM regions ranging from 0 GW to 64 GW
- 2011-2030 growth rates ranging from -22% to +41%
- Installed coal capacity in 2030 ranging from 12 GW to 267 GW
- Installed renewable capacity in 2030 ranging from 104 GW to 467 GW
- Average gas costs from $2.61/MMBtu to $10.23
- Additional hardened transfer capabilities ranging from 0 MW to 64 GW
- Total Eastern Interconnection transferred energy in 2030 ranging from 276 TWh to 1,268 TWh

A proprietary Multi-Region National (MRN) economic model and the North American Electricity and Environment Model (NEEM) were used for the macroeconomic studies. In the NEEM model the Eastern Interconnection is modeled as a simplified set of regions (bubbles) connected by a simplified network of transmission (pipes). One key assumption[4] of the NEEM model is that transmission constraints between the bubbles are an input, and the model normally locates generation in the most cost effective location based on all inputs including those transmission constraints. In this study effort, the pipes were allowed to expand for specific futures and sensitivities to test whether cost-effective generation would be located differently if the transmission system were expanded; these were known as soft constraint runs. For each of these cases, the SSC reviewed the study results from the soft constraint runs and made a decision as to the size of the transmission pipes to use for subsequent analyses. These soft constraint runs were completed as the initial sensitivity runs for the applicable futures, with the SSC-selected transmission pipe sizing being utilized for the purpose of all additional sensitivities for each future. If the transmission pipes were larger than the original pipes the Planning Coordinators worked together to determine what type of added transmission would be needed to meet those pipe sizes and developed a high level cost

[4] A second key assumption that will impact the Phase 2 work of the Planning Coordinators is that, within the NEEM "bubbles", it is assumed that there are no transmission constraints. In Phase 2 any transmission constraints that occur within the bubbles will be identified and transmission may be needed to alleviate those constraints.

estimate for that added transmission. In addition to the transmission, the NEEM model provided numerous outputs including generation retirements and additions by fuel type and region for review by the stakeholders.

In addition to the direct outputs from the NEEM model and the information provided by the Planning Coordinators on additional needed transmission, the SSC requested additional cost estimates that did not come directly out of the model. These included costs for significantly increased energy efficiency, demand response and distributed generation and costs associated with maintaining higher levels of reserve generation to integrate conventional generators and renewable generators. High-level estimates of such additional costs were provided by the SSC's Modeling Work Group (MWG).

The SSC formed a Scenario Task Force (STF) to review the outputs and choose the three scenarios that will be used in the Phase 2 analysis. The STF, and ultimately, the SSC, agreed that the main purpose for Phase 2 was to analyze a range of transmission buildouts that reflect distinct policy scenarios of interest to stakeholders. As articulated by the STF in a memorandum to the SSC summarizing their recommendations on the objectives, process, and criteria for scenario selection:

> "The main, guiding objective for the selection of scenarios to be studied in Phase 2, is to end up with a set of scenarios that are defined by different policy drivers, and to determine what different transmission buildouts may be needed to support these policy drivers."

The process developed for selecting the Phase 2 scenarios necessarily reflected the complexity of the decisions to be made. Two concepts discussed during the May 2011 SSC meeting were particularly influential in the design of the scenario development and selection process. The first is that of "bookends." Numerous individuals and sectors expressed a desire for scenarios that represent significantly different bookends, both in terms of the policy futures they embody, and the transmission buildouts they would likely require. The second key concept is that of "clustering" the Phase 1 Task 5 macroeconomic analysis results based upon similarities in their likely transmission requirements and other key variables, in an effort to ensure that the final scenarios selected for Phase 2 analysis would result in robust transmission buildouts, and would share some key features with other cases of interest.

The cluster analysis tool was made available to all stakeholders so that all could examine the clustering of the variables that were most important to them. An example of the cluster analysis below shows clusters resulting from comparing energy flows and percentage of renewable generation.

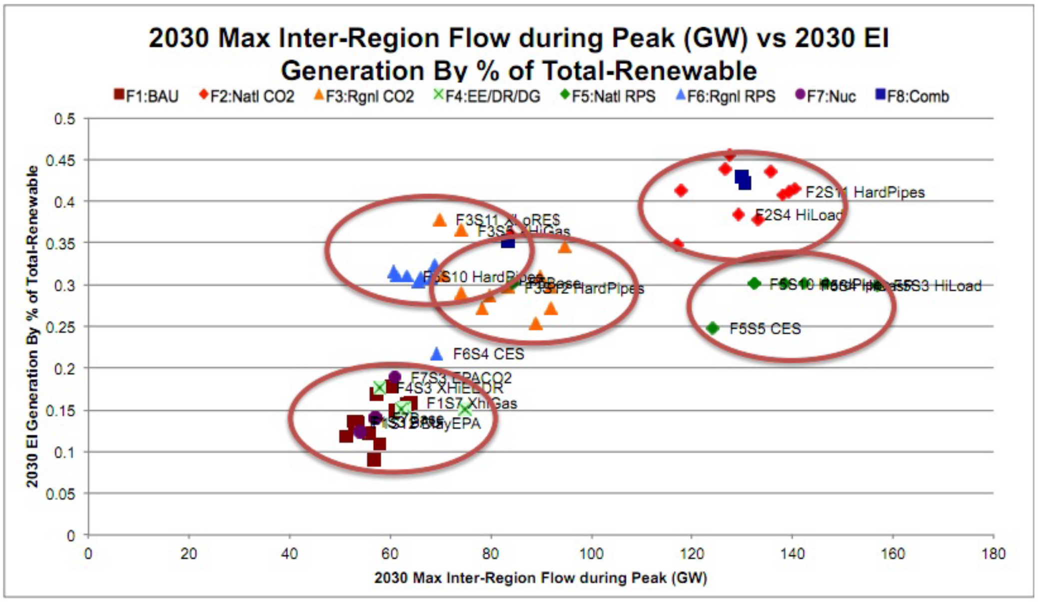

Figure 1: Energy Flow vs Generation By Percent of Total – Renewable

The cluster analyses discussed by the STF included expansion requirements, policy implementation options, and other variables of interest leading to identification of the three finalist scenarios that aligned with the "bookend" framework discussed above and other criteria. Principal metrics used were generation type, 2030 interregional flows to indicate transmission buildout, 2030 CO_2 reductions, and cost of the generation and transmission buildouts.

The final three scenarios, as shown in Table 2, were provided for EIPC to develop as full interregional transmission expansion models in the second phase of the work, following approval by DOE. They are considered to be balanced in terms of policy goals, levels of implementation, transmission buildouts, and total cost. The second phase of the work is scheduled for completion and reporting by December 2012.

Table 2: Scenarios for Phase 2 Studies

Scenario Descriptions	
Scenario 1: Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response (Based on F8S7)	Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050 combined with meeting 30% of the nation's electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, demand response, distributed generation, smart grid and other low-carbon technologies; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy. S7 is a sensitivity that has flat CO_2 prices after 2030, more wind in MISO_W, and the MISO combined cycle plants and MISO eastern wind are dispersed throughout the MISO regions and has hardened transfer limits.
Scenario 2: Regionally-Implemented National Renewable Portfolio Standard (Based on F6S10)	Meet 30% of the nation's electricity requirements from renewable resources by 2030; achieved by utilizing a regional implementation strategy. S10 indicates this was a run of the base case with hardened transfer limits.
Scenario 3: Business As Usual (Based on F1S17)	Continuation of forecasted load growth, existing RPSs, and currently proposed EPA regulations. S17 refers to adjustments made to intra-MISO combustion turbine distribution and SPP intermittency percentages and has hardened transfer limits.

The three scenarios chosen represent additional transfer capability needed between the NEEM regions ranging from 0 GW to 37 GW:

1. Scenario 1: Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response – 37 GW
2. Scenario 2: Regionally-Implemented National Renewable Portfolio Standard – 3-4 GW
3. Scenario 3: Business as Usual – 0 GW

Below are graphs showing the generation mix and loads for the Eastern Interconnection for each of the three scenarios chosen.

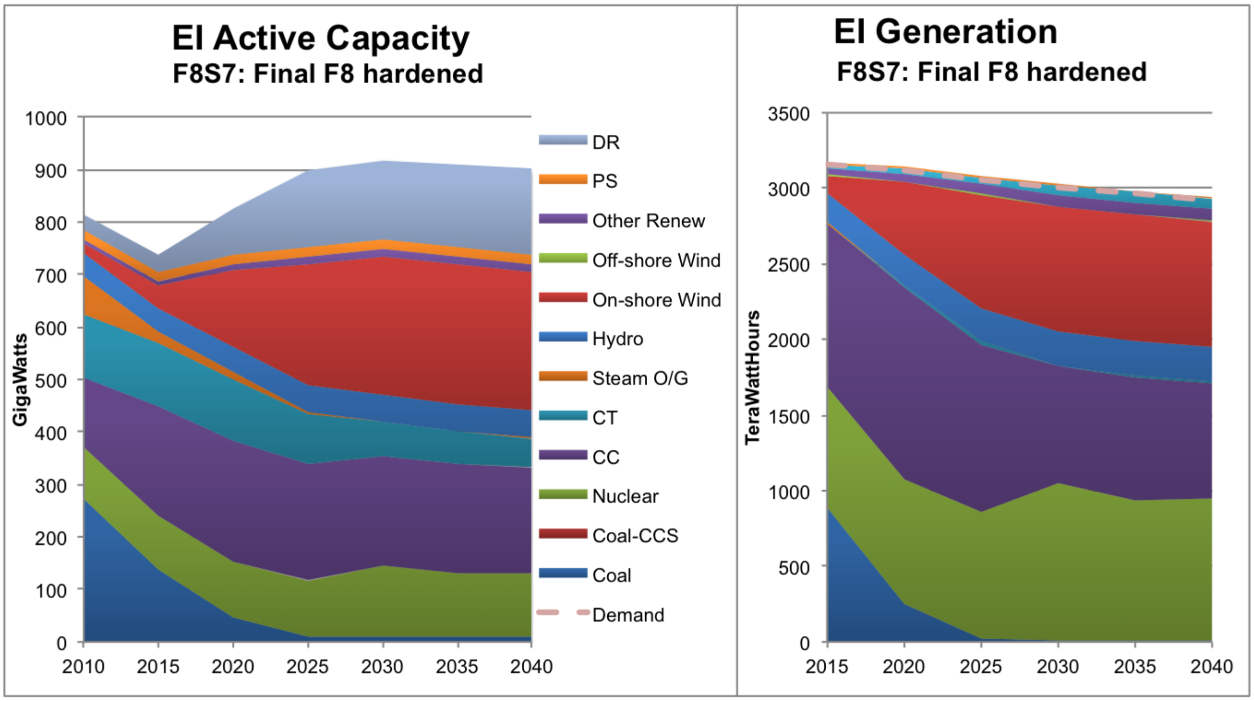

Figure 2: Scenario 1: Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response (F8S7)

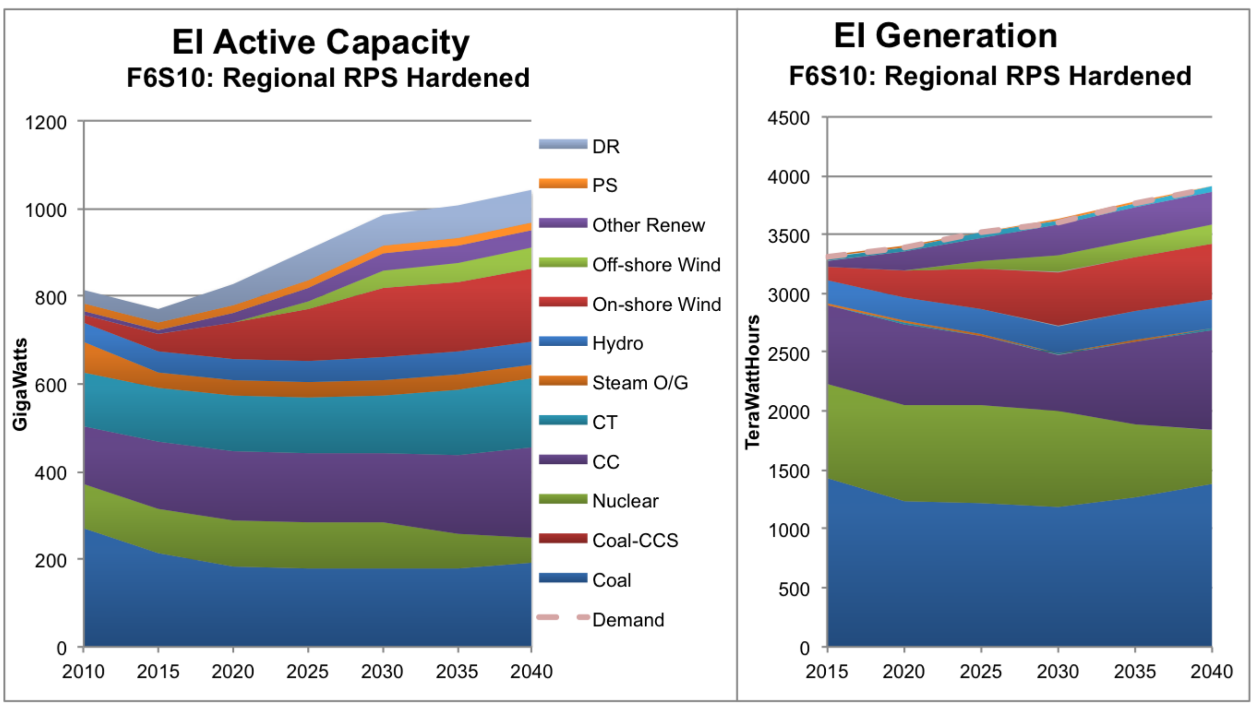

Figure 3: Scenario 2: Regionally-Implemented National Renewable Portfolio Standard (F6S10)

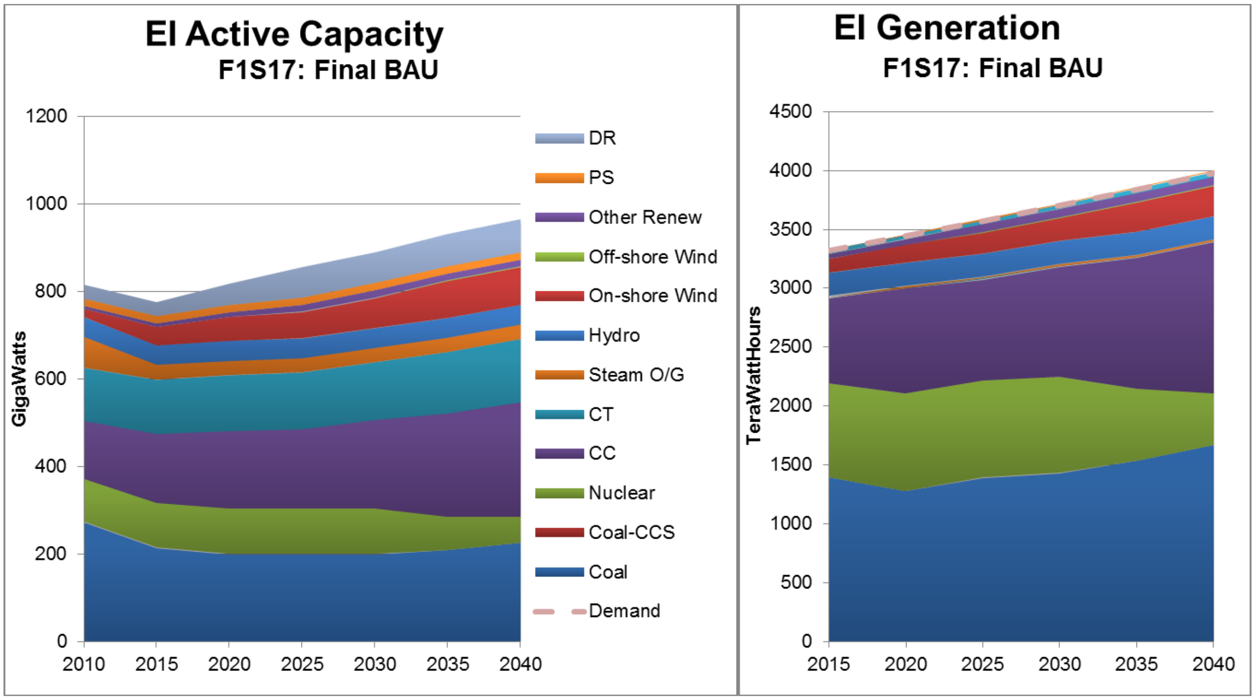

Figure 4: Scenario 3: Business As Usual (F1S17)

This report describes the work performed in the first phase of the Topic A EIPC project. While some conclusions of the Topic B work by EISPC are documented, in particular those on which subsequent work by EIPC depended, the detailed description of Topic B work will be provided in EISPC's final report at the end of their project.

The results of the Topic A Phase 1 work reported herein are intended to provide information to stakeholders, including policy makers, on the combinations of generation (including type of resource and location) and high level transmission transfer increases needed between the NEEM regions to support those generation resources. It will be apparent that any transmission expansions indicated from the macroeconomic studies do not provide a transmission plan, and the generic transmission infrastructure upgrades and high level cost estimates associated therewith as part of the Phase 1 analysis do not represent likely project solutions; rather, such information was developed as a data point to assist the SSC in determining the three scenarios to be analyzed during the Phase 2 studies. The choice of transmission line types and voltages for expansion of the pipes is standardized and does not reflect regionally optimal choices. Costs of substations, transmission upgrades (especially of lower voltage systems), financing, rights of way and routing, are details that are not included. Also, a comparison of the estimated expansion costs to the potential system savings to determine cost effectiveness was not considered. In Phase 2 of the work a more detailed transmission analysis will be developed for the three selected scenarios, but even with the additional detail the results will be indicative only and not representative of project solutions. Again many details such as transmission upgrades or expansion below 230 kV will not be considered. Additionally, although the results will be consistent with NERC reliability criteria, the studies will not include requirements for full compliance with NERC Standards. In all cases, any specific solutions will require study and integration in approved regional or interregional plans.

Following the completion of Phase 1 of the project, it is possible to draw some initial conclusions as follows:

- This project represents a unique dialog 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 show how to accommodate differing stakeholder chosen policy futures. The experience will help guide future and more focused efforts in addressing seams issues. 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 involving fewer participants than the analyses conducted by EIPC, the Topic A project work involving a larger team over the full eastern interconnection is proceeding well.
- The interaction between Topic A and Topic B participants also appears to be developing well into a communication capability that will serve the nation well in the future.
- We expect that the participants will use the experience for continuing and enhancing future joint planning studies and that all of these efforts will help guide the U.S. in considering and establishing potential national goals for energy.

1.0 Introduction and Background

The Eastern Interconnection Planning Collaborative (EIPC) received funding from the U.S. Department of Energy in 2010 to initiate a broad-based, transparent collaborative process to involve interested stakeholders in the development of policy futures for transmission analysis. Although this analysis focuses on a timeline beyond the 10-year horizon considered in existing regional planning processes, the effort required to perform this analysis is in line with the core function that EIPC envisioned when forming. This report describes the work performed in the first phase 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. They also provide the following:

- Increased opportunities for states and federal agencies to work cooperatively on planning, siting, and construction of 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, entities listed on the NERC compliance registry as Planning Coordinators manage their individual local and regional planning processes. The foundation of these local and regional planning processes is built upon input and feedback garnered from the stakeholders in each of the individual regions. The product of their effort generally results in a regional expansion plan for each Planning Coordinator Area. These regional expansion plans serve to provide insight on how the transmission system will evolve over a 10-year horizon. 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 will build upon, rather than replace, the current local and regional transmission planning processes implemented by the Planning Coordinators and associated regional stakeholder groups within the entire Eastern Interconnection.

The recent past has seen significant increases in intermittent resources built far from load new uses for electricity. All of these additional and expanded uses and sources for electricity were not envisioned when the existing transmission network (grid) was built in decades past. That is not to say that the grid’s performance has not served all of these expansions to electricity service well. In fact, the grid has performed well (barring unforeseen and unavoidable natural disasters, etc.). However, today’s electricity grid in the Eastern Interconnection as a whole is generally being used at, or near, full capacity. That means that the time is now to start thinking about the size and type of grid that may be needed in the future, especially if new energy and environmental laws, such as a national Renewable Portfolio Standard (RPS) or a national carbon-reduction law, are enacted.

1.1 DOE Funding Opportunity Announcement – Overview and Purpose

In June 2009, the United States Department of Energy (DOE) issued a Funding Opportunity Announcement (FOA), DE-FOA-0000068, which provided funding[5] 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. Under the collaborative, the NERC registered Planning Coordinators in the Eastern Interconnection intended to “roll-up,” analyze and, as needed, enhance their respective regional expansion plans which were developed under their FERC Order 890 approved regional planning processes to form a model of the Eastern Interconnection. This model was intended to provide a basis for interconnection-wide analysis that would feed information back into regional planning processes and allow EIPC members to coordinate regional plans while also allowing members to identify potential opportunities for transmission enhancements to increase the ability to move power to reduce costs. The core objectives served as the foundation for a proposal that PJM Interconnection, LLC (PJM), on behalf of EIPC, submitted in August 2009 to perform the Topic A work under the DOE FOA. All 26 EIPC members[6] support the work prescribed for Topic A. Eight of the 26 members are designated as Principal Investigators[7] who bear additional responsibilities with respect to project execution, management, and reporting. PJM serves as the lead Principal Investigator for the project.

The Eastern Interconnection Topic A cooperate 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)

[5] Funding made available under the American Recovery and Reinvestment Act of 2009 (ARRA 2009).
[6] As of December 1, 2011, the EIPC Members include Alcoa Power Generating, American Transmission Co., Duke Energy Carolinas, Electric Energy Inc., Entergy Services, Florida Power & Light, Georgia Transmission Corp, IESO, International Trans. Co., ISO New England, JEA, LG&E/KU, MAPPCOR, Midwest ISO, the Municipal Electric Authority of Georgia (MEAG), NBSO, New York ISO, PJM Interconnection, PowerSouth Energy Coop, Progress Energy Carolinas, Progress Energy Florida, South Carolina Elec. & Gas, Santee Cooper, Southern Company, Southwest Power Pool and Tennessee Valley Authority (TVA).
[7] Principal Investigators for the project include Entergy Services, ISO New England, MAPPCOR, Midwest ISO, New York ISO, PJM Interconnection, Southern Company, and TVA. American Transmission Co. is also a subrecipient to the DOE grant.

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). This was the first time that all of the Eastern Interconnection States had come together as a body to focus on pro-actively studying the future of its energy grid. 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 strive to coordinate their efforts.

Before this effort, the full complement of Eastern Interconnection States have not had the opportunity to come together face-to-face as a body and learn about each others' views and challenges, nor have the States had the need to come together to focus on the tasks set forth in the cooperative agreement. This, in and of itself, has proven to be beneficial for all members to gain a greater understanding of what states in other parts of the Eastern Interconnection are facing and to gain a greater understanding of resource and transmission planning processes and methods. The same may be said for the opportunity that the States have had to come together with the Planning Coordinators and Stakeholders to gain a greater understanding of their views and challenges and, in turn, be able to impart the States' views and challenges along with working collaboratively on the study tasks.

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. Further information regarding EISPC's organizational structure is provided in section 2.1.6.1 of this report.

1.2 Statement of Project Objectives

PJM's and NARUC's awards each incorporate 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 this 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 of Work

The scope of work proposed by the EIPC in the SOPO was divided into 14 tasks within two phases. Phase 1 included the following tasks:

- Task 0 – Project Management and Planning
- Task 1 – Initiate Project
  - Meet with EISPC to discuss interaction between entities and to gather feedback on Stakeholder Steering Committee (SSC) structure.
  - Facilitate the formation of the SSC and any necessary subgroups.
- Task 2 – Integrate Regional Plans
  - Generate Roll-up Model using regional plans for year 2020.
  - Perform interregional analysis on Roll-up Model.
  - Indentify conflicts between plans and/or opportunities for regional plan improvement.
- Task 3 – Production Cost Analysis of Regional Plans
  - Perform production cost analysis on Roll-up Model.
- Task 4 – Macroeconomic Futures Definition
  - SSC to reach consensus on eight futures [each future having up to nine sensitivities totaling 80 model runs (8 futures + 72 sensitivities)].
- Task 5 – Macroeconomic Analysis
  - Perform macroeconomic analysis and report on each future and sensitivity.
  - Produce high-level transmission cost estimates for each of the eight futures.
- Task 6 – Expansion Scenario Concurrence
  - Assist SSC in selecting three scenarios based on the Task 5 work as options for the transmission expansion, analysis, and costing work in Phase 2 of the project.
  - Produce interim project report on Phase 1 activities.
  - Present a draft(s) of Phase 1 report, respond to questions, and solicit input from stakeholders.

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[8].
- Task 8 – Reliability Review
  - Perform reliability analysis consistent with NERC reliability criteria on each scenario.
- Task 9 – Production Cost Analysis of Interregional Expansion Options
  - 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.
  - SSC to provide 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 change was related to Task 2 regarding the development and use of the Roll-up Model. Following study of the detailed aspects of the various regional plans that EIPC utilized for the Roll-up Model development, the SSC requested that EIPC revise the Roll-up Model to construct an SSI Model. Through a process initially led by EISPC, the SSC agreed to a revised set of transmission and generation assets that would serve as the basis for a revised Roll-up Model for 2020. This new SSI Model replaced the Roll-up Model and served as the starting point for all of the remaining DOE project work.

The second change to the SOPO related to the production costing work that was planned under Task 3 in Phase 1 of the project. Under the original proposal, a production cost analysis would be performed on the integrated regional plans that served to create the 2020 Roll-up Model. With the replacement of the Roll-up Model by a stakeholder derived SSI Model as the starting point for further analysis, and with the decision to consider a 20- to 25-year time horizon rather than the 10-year horizon assumed in the integrated regional plans used to derive the Roll-up Model, the SSC agreed that this work was no longer providing meaningful value to the project. At the request of PJM, in May 2011, DOE, deleted Task 3 from the SOPO.

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[8] This activity is intended to provide high-level interconnection-wide expansion analysis and not to substitute for regional planning processes or state, local or provincial siting processes. The models will not identify specific routing, siting, environmental, or other related issues associated with any potential enhancements to the grid coming out of this task.

The Eastern Interconnection Topic B project, EISPC, has a SOPO including objectives, scope and tasking.

Per the 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; e.g., renewable-rich areas with suitable topographic and other characteristics for either variable or baseload generation, including but not limited to non-terrestrial areas particularly suited to offshore wind and ocean power technologies, areas with geology or other characteristics particularly suited to carbon capture and sequestration (CCS), or areas otherwise particularly suited to other forms of low- or no-carbon electricity generation. The Recipient will allow for regional diversity and determine how the 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, studies on availability of baseload renewables and other low-carbon resources, as well as 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. This process shall be open to all relevant technologies and afford ample opportunity for participation by state governors, provincial ministers, their designees, and state or provincial utility regulatory officials.

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 – Preparation of whitepapers.
- 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 buildout scenarios to be conducted by the Eastern Interconnection Topic A Recipient.
- Task 8 – Participate in Eastern Interconnection Topic A activities.

EISPC tasks will be discussed after each of their counterpart EIPC tasks with the exception of EISPC Tasks 4 and 5. These tasks are EISPC's tasks. As such, they are outside of the scope of this EIPC Phase 1 report. EISPC will report separately on Tasks 4 and 5 at the conclusion of those tasks.

1.4 Overview of Project Schedule

The DOE FOA specified that the project work is to be completed by June 30, 2013. The restructured EIPC proposal that was submitted in February 2010 called for Phase 1 work to be complete by June of 2011 and for Phase 2 work to be complete by June of 2012, well ahead of the June 2013 deadline. A revised schedule was issued in mid-2011 that moved completion of Phase 1 of the project to December 2011 and completion of Phase 2 to December 2012, still well ahead of the original June 2013 deadline set in the DOE FOA.

The extension to the original schedule was the result of EIPC support of SSC efforts to create the SSI Model, extensive stakeholder education regarding the operation of, and input assumptions needed for, the macroeconomic models, and by the additional time necessary for the SSC to reach agreement on the futures and associated sensitivities for the Task 5 work. The modifications to the schedule were supported by the DOE and by the SSC as they served to allow the EISPC and SSC to make decisions essential for supporting the stakeholder process. EIPC anticipates no further delays in the project schedule, at this point. Even in the event of modest schedule changes during the remaining work, EIPC is confident that the original June 2013 deadline spelled out in the DOE FOA can be met.

1.5 Unique Study Characteristics

- This is a first of its kind effort for the Eastern Interconnection.
- Complexity and differences among the regions should be accommodated.
- Stakeholders should consider Phase 1 in context of overall project – to develop transmission alternatives.
- Phase 1 is not an end unto itself.

- SSC provided modifications to the roll-up as a starting point for resource analyses.
- SSC negotiated input assumptions need to be placed into context.
- Macroeconomic models are used for many broad ranging studies – were proposed to assist stakeholders to determine the final three scenarios – not as an end unto themselves.
- Because of the complexity of factors involved in this type of study, there was never any intent to optimize or “co-optimize” every input to the model.
- Stakeholder consensus process was somewhat unwieldy but worked well to the extent that needed decisions were eventually made.
- 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.
- Process has provided all participants with a great deal of information that should be useful if similar studies are done in the future.

2.0 Study Results by Task

2.1 Task 1 – Initiate Project

The Statement of Project Objectives provides the following subtasks regarding initiating the project within Task 1:

Subtask 1.A – Adjust structure of SSC as needed.
Subtask 1.B – Commission the SSC.
Subtask 1.C – Select SSC members.
Subtask 1.D – Establish SSC By-Laws, elect officers.
Subtask 1.E – Project task and scope development.
Subtask 1.F – Develop process for selection of NGOs and Consumer Advocate (CA) groups.

The SSC was formed in a four-step process: 1) assessment, 2) development of the SSC composition and role, 3) development and implementation of the SSC selection process, and 4) development and adoption of the SSC Charter. The formation of the SSC was a significant milestone as the first time that stakeholders from all major interest groups across the Eastern Interconnection came together to discuss long-term resource options and related infrastructure needs in the 39-state region, the District of Columbia, the City of New Orleans, and the Eastern Canadian provinces.

In parallel with the development of the SSC, EISPC established its own governance structure and decision-making processes described later in section 2.1.6.1. EIPC and EISPC have collaboratively coordinated meeting schedules, work products, and decision-making.

2.1.1 Assessment Phase (September 2009 – February 2010)

The Keystone Center (Keystone), the subcontractor responsible for managing the stakeholder process, determined that an assessment should be conducted to fully develop the SSC make-up and its process for engaging a wide range of stakeholders. Acting for EIPC, Keystone conducted an initial round of interviews with known stakeholders active in the energy and transmission fields. These interviews produced both information for understanding stakeholders' interests as well as additional names of people who were knowledgeable and had a stake in the development of the transmission system in the Eastern Interconnection. A second round of interviews was completed with a subset of stakeholders currently participating in each of the EIPC Planning Coordinators' FERC Order 890 transmission planning processes.

As part of the assessment phase, EIPC and Keystone planned and hosted two webinars to inform interested parties about its evolving work plan and the overall objectives of the project. EIPC reviewed the plan of work set forth in the bid documents during the October 2009 webinar and answered a number of questions. Each webinar was attended by over 200 participants.

EIPC created a Web site (www.epiconline.com) at this early stage, and Keystone later took over management of the site to provide stakeholders with easy and timely access to information about all aspects of the project. Listservs were established for all registered stakeholders to receive notification of project events and postings.

2.1.2 Development of the Stakeholder Steering Committee Composition and Role (February 2010 – August 2010)

Based on the results of stakeholder interviews and analysis of the FERC Order 890 stakeholder committee processes, in coordination with EIPC, Keystone drafted a straw proposal for composition of the SSC. Keystone also designed a proposed process for fairly, and transparently, selecting individuals to serve on the SSC. Guiding principles for the stakeholder process and the SSC included the following:

- The stakeholder process should be inclusive so the interests of all relevant stakeholders should be represented within each sector.
- The process should build upon the existing stakeholder FERC Order 890-approved processes.
- The SSC should be a manageable size and allow decisions to be made through consensus.
- There should be balanced representation among the sectors.
- State representatives will have at least one-third of the total SSC seats.[9]
- There should be ongoing communications among SSC members and their interest group sectors.

This proposal for composition of the SSC and its voting process was reviewed by DOE, EIPC and interested parties from the relevant sectors proposed to comprise the SSC at various times during this period. The proposal was presented for comment during two webinars in March 2010. Finally, the proposal was discussed at length during the April 2010 Stakeholder meeting, and finalized through a series of open conference calls.

The final SSC structure, approved in April 2010, was as follows:

- **Transmission Owners and Developers:** Three members. See eligibility criteria on page 2 at http://eipconline.com/uploads/EIPC-SSC_Description_FINAL.pdf
- **Generation Owners and Developers:** Three members; minimum one renewable and one non-renewable

[9] As the Topic B awardee, EISPC representation in the SSC was predetermined by DOE contract to constitute one-third to one-half of the total SSC membership, with the significant role of coordinating the input of 39 states, the District of Columbia, and the City of New Orleans and working collaboratively with other SSC sectors to provide a coherent stakeholder voice to support the research, modeling, and deliberations of the EIPC project.

- **Other Suppliers** (e.g., power marketers, energy storage, distributed generation): Three members; minimum one demand-side resources representative
- **Transmission-Dependent Utilities, Public Power and Co-ops** (e.g., municipal utilities, rural co-ops, power authorities): Three members; minimum one public power or cooperative transmission-dependent utility (TDU)
- **Non-Governmental Organizations** (NGOs): Three members
- **End Users** (e.g., small consumer advocates, large consumers): Three members; minimum one state consumer advocate agency
- **State Representatives** appointed by EISPC: Ten members
- **Canadian Provincial Representatives** appointed by Canadian Provinces: One member

2.1.3 Development and Implementation of the SSC Selection Process (May 2010 – July 2010)

A key principle for the SSC members' selection process was to include all interested stakeholders. To meet this objective, EIPC directed Keystone to undertake a number of activities to communicate with the stakeholder community. In addition to listservs and the Web site, Keystone instituted a monthly newsletter summarizing decisions and posted upcoming events for distribution to the listserv, created an on-line process for selection of Sector Caucus and SSC members, and hosted a webinar to explain the selection process.

The SSC selection process was designed in two phases. First, each region of the Eastern Interconnection (see text box) selected three representatives from each of four sectors (Transmission Owners and Developers, Generation Owners and Developers; Other Suppliers; and TDU, Public Power and Co-ops). The End User and NGO sectors selected their representatives from across the Eastern Interconnection. These individuals were the designated Sector Caucus members. EISPC developed its own selection process to appoint the state SSC members.

To begin the Sector Caucus selection process, Keystone asked sectors to appoint coordinators from each region (seven regions and eight sectors or 56 coordinators, with some being responsible for more than one sector and/ or region). Their contact information was posted on the EIPC Web site to allow the broader stakeholder community to learn about and participate in the process via e-mail and/or communicate with the sector/region coordinator.

Eastern Interconnection Regions for Selection of Caucus Members

PJM Interconnection (PJM)

Midwest Independent System Operator (MISO)

Mid-Continent Area Power Pool (MAPP)

New York Independent System Operator (NYISO)

Independent System Operator of New England (ISONE)

Southeast Inter-Regional Participation Process (SIRRP)

Southwest Power Pool (SPP)

Florida

Eastern Canada

In addition to sector-coordinated contact information, each region and sector submitted its process for selecting representatives, the SSC candidates, dates and times for voting/ decisional meetings, and voting and consensus rules and procedures. Concerns and objections to the process were required to be resolved before voting could take place.[10] Regional/ sector representatives were encouraged to host preparatory forums to allow interested stakeholders within each sector to discuss any issues and pose questions, although such forums were not uniformly held due to tight timeframes.

During this period, EIPC drafted additional guidance on the Sector Caucus member selection process, including the following:

- Information to be supplied by candidates.
- Candidate eligibility for a given sector or seat; i.e., definition of a material interest in the region.
- Voter eligibility.
- Transparency procedures.
- Creation of a ranked voting system for the on-line process.
- Procedure for subsector voting.
- Voting contingencies; e.g, tie votes, interpretation of results when no one votes, procedure for unfilled caucus seats.
- The role of proxies or alternates.
- Process for selecting replacements when Sector Caucus or SSC members resign.
- Process for addressing stakeholder objections.

The process for voting was then detailed in the *Step-by-Step* document and *Frequently Asked Questions (FAQ)* available online at http://eipconline.com/SSC_Resources.html. The final voting for Sector Caucus members took place between June 15 and 16, 2010. The results were verified and posted to the EIPC Web site on June 18, 2010.

After Sector Caucus members were selected, the second stage of the process began – selection of the SSC members by the Sector Caucuses.

The stakeholders had agreed earlier that criteria for SSC candidacy should include the following:

- Seniority, stature and credibility within one's organization and sector.
- Demonstrated ability to represent the interests of multiple organizations within the sector.
- Broad support of organizations and constituency groups within the sector.
- Ability to keep sector participants across the Eastern Interconnection informed about SSC activities and to solicit input throughout the project.
- Demonstrated ability to work collaboratively with others with whom one disagrees.

[10] The principles and guidelines for the selection process were enforced by responding to complaints from sector stakeholders. Very few complaints were received and required investigation and resolution.

- Strong understanding of resource and transmission planning in the electricity industry, including technology and policy considerations.
- Time, commitment, and resources for full participation.

Each Sector Caucus could select an SSC member from within its ranks or select someone from outside the Caucus by mutual agreement. Sector Caucus members interested in being considered for the SSC completed a candidacy application that was posted to the EIPC Web site, and voting took place on-line, by phone or email, or in person. The same requirements for transparency and inclusiveness applied so that any stakeholders could observe the process and submit objections if they were concerned about eligibility or fairness requirements. Each subsector elected its own subsector SSC members, so for instance, the Renewable Generation subsector of the Generation Owners held a separate election for their SSC representative.

After the voting results were tabulated by Keystone, and verified by EIPC, the SSC member names were publicized and posted on-line on July 1, 2010.

2.1.4 Development and Adoption of the SSC Charter (February 2010 – October 2010)

Concurrent with active stakeholder outreach during the fall of 2009, Keystone began to compile potential resources for an SSC Charter or rules of governance. Based on a review of other steering committee charters, Keystone worked with EIPC to develop a straw proposal for consideration by stakeholders in advance of the April 2010 Eastern Interconnection-wide Stakeholder meeting. In a May 14, 2010 memorandum developed collaboratively through conference calls and written comments, a number of governance issues were decided, including the following:

- The purpose of the SSC.
- The role of Sector Caucus members after the selection process.
- SSC roles and responsibilities.
- Possible role of a chair or chairs.
- The role of work groups.

At the first SSC meeting, a number of outstanding governance issues were discussed and ultimately assigned to a Governance Task Force composed of one representative from each sector. Unresolved questions included the following:

- SSC leadership and selection of Chair(s).
- Term limits of SSC members.
- Terms for alternates' attendance.
- Meeting ground rules.
- Decision making for non-substantive issues.
- Communication outside of SSC.
- Creation and role of work groups.

Other important issues were resolved between the first and second meeting, including selection and roles for Sector Table Representatives, table arrangements at the SSC meetings, and guidance on sufficient notification and distribution of materials prior to SSC meetings.

After several months of facilitated calls, the Governance Task Force presented its recommended Charter to the SSC, which was discussed, amended and adopted by consensus at the October 12-14, 2010 SSC meeting.

Two key elements of the Charter were the selection of a chair or chairs and the process for making decisions in the event consensus could not be reached. The alternative to consensus is a formula for "backstop voting" in which 19 SSC members must first agree that consensus cannot be reached. Once it is established that consensus cannot be achieved, 23 members must vote in favor of a proposed resolution to the issue under debate. Provisions were also made to ensure that two sectors alone could not block agreement on an issue. It should be noted that over the course of Phase 1 the backstop voting process was never formally invoked.

On October 12-14, 2010, the SSC elected by closed ballot a chair and vice-chair. The SSC Charter instituted a rotating schedule of service, so that the Chair and Vice Chair retained their respective offices for 6 months and then changed positions. After the second 6-month term was completed, the SSC agreed it would consider how to continue and whether to alter the system for choosing or retaining Chair leadership. The SSC did address this issue at the end of the twelve months and decided that the Chair/Co-Chair system works well and should be retained.

The SSC agreed to meet in person approximately every other month to accomplish the Phase 1 tasks. Later, this meeting schedule was amended to include scheduling of SSC webinars in the non-meeting months to attend to any issues that needed a consensus decision, and also to provide work group updates for SSC members.

2.1.5 Creation of the Work Groups

Initially, three work groups were established – Roll-Up Work Group (RUWG), Scenario Planning Work Group (SPWG), and Modeling Work Group (MWG). The SSC drafted and approved the charge to each work group and agreed that the work groups would develop recommendations for the SSC but had no independent decision-making authority. Each sector appointed up to three representatives to each work group, in addition to the ex-officio members from DOE and EPA and an EIPC liaison. Each sector was also allowed as many non-SSC/non-Sector Caucus participants (e.g., technical experts) as necessary to assist in the work group activities. Each work group selected a chair or co-chairs to serve as the primary point of contact for the SSC and EIPC. EISPC also created counterpart workgroups, using the same workgroup names as created by the SSC, comprised of EISPC members, members' staffs and consultants. The EISPC workgroups' tasks were to provide independent analysis and assistance to EISPC as well as to participate in the SSC's workgroups and advise EISPC on the SSC's workgroups' recommendations. As such, the actions of the SSC's workgroups discussed in this report include the work of EISPC's workgroups.

Over the course of Phase 1, the Governance Task Force reconvened to address proposed changes in the Charter and a new task force was created, the Scenario Task Force, to develop recommendations on the three scenarios to be analyzed during Phase 2.

2.1.5.1 *Roll-Up Work Group (RUWG)*

The SSC charged the RUWG with the following responsibilities:

- Liaise with and provide feedback to EIPC as EIPC develops the integration of the existing regional transmission plans and addresses potential enhancements identified through a gap analysis of the Eastern Interconnection-wide 2020 Roll-Up Integration Case. These activities are identified as Task 2 in the Statement of Project Objectives; however, the group expects that its charge will extend to other tasks if the roll-up plan affects either the economics or reliability of macroeconomic futures or transmission buildout scenarios.

- Establish a close interface and coordination with the SPWG so that the conclusions and results of the roll-up study effort are understood in connection with futures development and scenarios planning.

2.1.5.2 *Scenario Planning Work Group (SPWG)*

The charge of the SPWG was approved by the SSC in July 2010.

- Recommend to the SSC a set of diverse macroeconomic futures for selection, and if so directed by the SSC, make recommendations as to the eight futures to be analyzed and up to nine sensitivities to be used within each.
- Fully develop the eight macroeconomic futures and the sensitivities selected by the SSC, so that they meet CRA's needs.
- Recommend to the SSC which three scenarios should be assessed in Phase 2.[11]

The SPWG objectives were established as follows:

- The portfolio of eight macroeconomic futures will represent a wide range of forecasts.
- The portfolio will consider factors such as state and federal public policy objectives, reliability mandates, and economic considerations.

[11] Subsequently, the SSC elected to assign the task of recommending the three scenarios to be analyzed during Phase 2 to the Scenario Task Force.

- The SPWG will effectively coordinate with the MWG as the purposes of these groups are interrelated and outputs will be informative to one another.
- The portfolio of macroeconomic futures will be recommended to the SSC as the consensus position of the SPWG. If the working group is unable to reach consensus on eight recommended macroeconomic futures, a range of opinions or additional futures may be presented.
- The SPWG will inform and receive input from the SSC throughout the process such that the SSC endorses the portfolio proposed by the SPWG, or alternatively, will find that the SPWG has helped the SSC to substantially narrow the range of issues to be debated by the SSC in sufficient time to meet the overall EIPC schedule.
- The SPWG will fully coordinate and collaborate with EISPC, since EISPC ultimately can decide four of the macroeconomic futures and one of the Phase 2 scenarios.
- The SPWG will coordinate with the RUWG as needed.

2.1.5.3 *Modeling Work Group (MWG)*

The SSC defined the purpose of the MWG as the following four functions:

- Develop a better understanding of the capabilities, inputs and assumptions, and outputs of the CRA MRN-NEEM (macroeconomic) model that will be used to evaluate the eight macroeconomic futures and sensitivities and the GE MAPS (production cost) model that will be used to analyze the roll-up plan and the final three transmission buildout scenarios.
  - Identify concerns or issues, seek answers, make recommendations and report to the SSC regarding the MRN-NEEM and GE MAPS modeling to be performed.
- Identify with CRA the matrix of specific required inputs for MRN-NEEM to be provided by SSC and advise the SSC and SPWG on model inputs, outputs, processes and limitations to assist them in the development of the eight macroeconomic futures.
  - Coordinate with the RUWG to identify any issues that could impact model inputs, assumptions, modeling, or results.
- In coordination with, and within the parameters set by, the SPWG, make recommendations to the SSC on the values for the inputs and assumptions to be used for modeling the eight macroeconomic futures.
  - Identify as appropriate data or analyses need.
  - Work with resources; e.g., DOE, national laboratories.
  - Collaborate with CRA to ensure model consistency.
- Review outputs and results of MRN-NEEM and GE MAPS modeling and provide a report on the interpretations to SSC.

The SSC also directed the MWG and SPWG to work closely together “because their purposes are interrelated and their outputs will be informative to one another, particularly as they determine how to proceed with developing the assumptions and inputs for the macroeconomic model.”

2.1.5.4 *Scenario Task Force (STF)*

The SSC created this task force to lead the effort under Task 5 to develop recommendations to the SSC for the three final scenarios for transmission analysis under Phase 2. The following guidelines were adopted by the SSC to govern the membership and work of the STF:

- Each sector has one designee, except EISPC, which has three. These individuals represent their sectors in any decision-making undertaken by the task force. EIPC also has a liaison to the task force.
- All recommendations made by the task force will be subject to approval by the entire SSC.
- Task force calls and meetings are open to the participation of all interested SSC members and other stakeholders.

2.1.6 EISPC Tasks 1, 2, and 8

2.1.6.1 *EISPC Task 1 – Organizational Development and Project Management*

EISPC's first task includes four subtasks:

- Subtask 1.A – Form an Executive Committee.
- Subtask 1.B – Develop EISPC organizational structure and operating protocols.
- Subtask 1.C – Hire EISPC staff and set up of office space
- Subtask 1.D – Identify key stakeholders that need to be involved in the collaborative effort, revise and maintain the Project Management Plan, assess issues such as the ability to obtain and protect confidential information among the Eastern Interconnection Topic A and Topic B Recipients required to conduct the studies.

In anticipation of DOE funding, state representatives began developing EISPC's organizational structure to include the 39 States within the Eastern Interconnection and the District of Columbia. EISPC determined that each State would be allowed two voting members and encouraged the States to consider designating one member as a representative of its state energy regulatory commission and the other member as a representative of its Governor's Office. Because of its unique jurisdictional arrangement, the City of New Orleans petitioned to become a member separately from the State of Louisiana. EISPC considered the City's petition and decided to allow the State of Louisiana to have one member seat and the City of New Orleans to hold the other member seat. Also, because of the close electricity-service ties between the Midwest and eastern Canadian Provinces and some or most of the northern States, the eight Canadian Provinces were invited to join EISPC as non-voting ex officio members.

Once the membership structure was set, EISPC turned to formulating its governing structure. In order to ensure that states in each of the five regions within the Eastern Interconnection (the Northeast, Mid-Atlantic, Southeast, Southwest and Midwest) are represented, EISPC determined that its governing Executive Committee should be comprised of five members with each member from one of the States in each region. EISPC also used this regional balance to set up a Nominating Committee which nominated candidates from each region for the Executive Committee as well as the offices (President, Vice President, Secretary, Treasurer and At-Large Member) within the Executive Committee.

EISPC next turned its attention to determining how it would represent itself on the SSC. By agreement with DOE and EIPC, EISPC is allowed ten voting members on the SSC. EISPC decided that five of those seats would be held by the five Officers on the Executive Committee and five of the seats would be elected from the membership with one seat elected from each of the five regions. This arrangement ensured that each of the five regions of EISPC had two representatives per region on the SSC.

After these membership arrangements were set, a regionally-balanced Governance Committee was formed to develop By-Laws covering, among other aspects, committee duties, meeting structures, attendance, decision-making and voting. The By-Laws were discussed and revised a number of times until the EISPC membership approved them by unanimous consent early in 2010. Along with the By-Laws, other documents were crafted regarding the protection of confidential data and operating and reporting agreements between EISPC and NARUC.

EISPC also began searching for staff to assist in its work. Per the cooperative agreement, EISPC was allowed to hire a director, an economist, a transmission engineer, and an administrative assistant. NARUC retained half of the administrative assistant position to hire a half-time budget assistant and NRRI, the subcontractor to NARUC that assisted in structuring EISPC, retained the other half of the administrative assistant position to hire a half-time webmaster for EISPC's Web site. NRRI hired the EISPC director and economist during the fall of 2010. EISPC found that the budged salary for the transmission engineer position was not competitive with the market and was unable to hire an engineer despite many candidate searches. In the summer of 2011, NARUC approached DOE soliciting contracted engineering expertise to assist EISPC in completing its tasks, rather than continuing to attempt to hire a full-time engineer. NARUC subsequently issued a Request for Proposals to provide such engineering assistance to EISPC. As of October 21, 2011, six proposals have been submitted. The review of these proposals will seek to garner the most focused and efficient engineering assistance for EISPC as it enters the complex and detailed Phase 2 transmission planning studies.

2.1.6.2 *EISPC Task 2 - Reach consensus on the Recipient's position on modeling inputs and assumptions via expansion of transmission planning knowledge base*

EISPC spent significant time and effort during all EISPC meetings in educating its members on the various and complex aspects of resource and transmission planning. This education was essential to the members' understanding of the work of this project, as some State

Commissions are no longer involved with either type of planning due to legal or other constraints. EISPC hosted experts on various topics who gave presentations that provided not only technical information, but focused on targeting the audience so they could gain an understanding of each topic's importance and context in the overall project.

EISPC collaborated with EIPC and the SSC to identify key stakeholders, maintain the Project Management Plan, and develop plans to protect confidential data required for the project. Additionally, EISPC surveyed state energy efficiency and demand-side resource information and assisted in establishing costs to be used in the Phase 1 work by EIPC, the SSC and EISPC. Other examples of collaboration in the development of the costs, inputs, and assumptions are discussed throughout this report.

2.1.6.3 *EISPC Task 8 - Participate in Eastern Interconnection Topic A activities*

EISPC participates closely and actively in all aspects of SSC work. As discussed above in EISPC Task 1, EISPC has ten seats on the SSC. EISPC's ten SSC Representatives, or their Proxies, attend all SSC meetings, in-person and electronically, and actively advocate EISPC's decision to the SSC. EISPC makes a concerted attempt to prepare for each SSC meeting in order to take a leadership role in discussions and decisions by the SSC.

Each of the SSC Sectors named one of its SSC representatives to the STF and EISPC named three representatives from its roster of ten SSC members. The STF met during the summer of 2011 to examine processes and methods to assist the SSC is making its selections of the final three scenarios. EISPC's representatives regularly apprised EISPC of the STF's work in order to assist EISPC in the same regard. With the assistance of STF and the EISPC and SSC work groups, EISPC recommended to the SSC its selections of the three scenarios in the fall of 2011.

EISPC participates collaboratively with the members of the SSC's RUWG, MWG, and SPWG on the myriad of complex details underlying the work of EISPC and the SSC. EISPC representatives serving on the SSC MWG were involved in forming "sub-teams" to develop the required data inputs for the MRN/NEEM model.

In addition to the work mentioned above, the Executive Committee and staff of EISPC meet weekly with EIPC and SSC leadership to coordinate schedules, and discuss upcoming work, meeting logistics, agendas, task schedules, and deliverable positioning. This close coordination is beneficial and will continue throughout the remainder of the projects.

2.2 Task 2 – Integrate Regional Plans

The Statement of Project Objectives provides the following summary of work regarding the integration of regional plans to be performed within Task 2:

Sub-Task 2.A – Develop a study guide for documenting interregional analysis processes that refine the NERC Multi-regional Modeling Working Group (MMWG) modeling and regional plans as needed for Roll-up Integration Case analysis.

Subtask 2.B – Conduct interregional transmission analyses for Roll-up Integration Case and identify potential transmission conflicts/opportunities among regional plans; e.g., gap analysis.

Subtask 2.C – Develop transmission options to address reliability impacts associated with potential conflicts among regional plans.

Subtask 2.D – Document and communicate results for consideration in regional planning activities and post the analysis on the EIPC Web site.

Subtask 2.E – Develop flowgates.

In Task 2 the Planning Coordinators utilized the most recent vintage NERC Multi-Regional Modeling Working Group (MMWG) model representing the study year selected by the stakeholders, 2020. This model was revised and updated to reflect an aggregation of regional plans - plans which were provided by participating Planning Coordinators. Key inputs to this work were the NERC MMWG 2020 Summer Peak model, as developed by the NERC MWG in its 2009 in its vintage set of models, and regional plans, as known in 2010, which had been subjected to the regional planning requirements of FERC Order 890. The resultant 2020 model would be used as the basis for both the interregional analysis required by the project and the future analysis which would be chosen by the SSC in coordination with EISPC. As noted in the above subtasks, this model was known as the 2020 Roll-Up Integration Case.

The principal products of Task 2 are the 2020 Roll-Up Integration Case model, the interregional analysis of the model and transmission expansion options. This 2020 Roll-Up Integration Case is an integrated model of the combined expansion plans for the Eastern Interconnection as they existed in 2010, not a single “blueprint” for expanding the system. This case provides solved power flow modeling suitable as a starting point for transmission analysis on an interconnection-wide basis.

2.2.1 The Roll-Up

The roll-up results represented a significant first-of-its-kind effort by the Planning Coordinators to review each entity’s regional plan at an interconnection-wide level. Although interregional coordination activities are well established, and required under applicable FERC precedent, this effort provided a first opportunity for a much higher interconnection-wide view of the plans and a check as to their consistency across the regions. This effort yields an important body of information that can be utilized by policy makers, the Planning Coordinators, and their stakeholders in each entity’s subsequent regional planning efforts pursuant to FERC Order 890. In addition to the uniqueness of the effort, the roll-up produced some notable results.

The Planning Coordinators undertook a reliability analysis of the roll-up of the regional plans and found no significant reliability issues. Such a finding is noteworthy as it is indicative of the fact that the respective regional plans are not causing burdens that would manifest themselves as unsolved reliability violations elsewhere in the Eastern Interconnection. This is one important goal of the NERC reliability standards. Compliance with this goal was clearly demonstrated on an interconnection-wide basis through the roll-up and provides an important analysis that could be utilized in the future.

On a more granular level the roll-up revealed both commonalities and differences in the specific planning inputs used in each region. The differences are expected and, in fact, required given the diversity in the form of regulation, the diversity in market design throughout the interconnection, and the differing topography and characteristics of each Planning Coordinator's electric transmission system throughout the Eastern Interconnection. The Roll-Up Report at http://eipconline.com/uploads/EIPC_Roll-Up_Report_2011-03-07.pdf on the EIPC Web site describes in detail the data submitted by each of the EIPC Planning Coordinators, explains differences in the Planning Coordinators' respective planning processes, and assists the SSC in understanding what is contained in the 2020 Roll-Up Integration Case.

2.2.2 Stakeholder Specified Infrastructure (SSI)

The 2020 Roll-Up Integration Case as presented to the SSC in November 2010 was based on various analytical tools that had been utilized by Planning Coordinators in order to assess reliability requirements, interconnection and transmission service requests as well as the need for economic and market enhancements. Regional plans contained in the 2020 Roll-Up Integration Case were developed in accordance with FERC Order 890 regional planning requirements. These Order 890 regional planning requirements have established transparent processes that each Planning Coordinator incorporates which provide for the inclusion of stakeholders within their respective areas.

Even though the 2020 Roll-Up Integration Case was an aggregate product of Order 890 regional planning processes in the Eastern Interconnection, stakeholders, including the states, expressed concerns relative to the status and "reasonable certainty" of certain generation and transmission facilities found in the model which were projected to come into service through 2020. FERC Order 890 allows for "regional differences" in planning criteria and processes. Therefore, the 2020 Roll-Up Integration Case reflected regional differences in the relative certainty of generation and transmission facilities' development depending on such factors as the degree of state approval authority over such generation and transmission development, the degree to which generation is developed under a competitive market model, as well as differing regional needs and requirements associated with renewable portfolio standards. As a result of these concerns, the SSC agreed to develop an alternative approach to determining which of the planned generation and transmission would be included as the starting point for the analysis to be performed in Task 5 of the project. EISPC also embarked on a similar task.

The SSC adopted a two-step approach for determining whether a planned generation or transmission facility would be included in the model as the starting point for the Task 5 analysis. To make it unique from the 2020 Roll-Up Integration Case model, the model which evolved under the SSC-specified criteria became the Stakeholder Specified Infrastructure (SSI) model. The two steps in the SSC's development of the model were:

1. Define criteria by which generation and transmission additions from the 2020 Roll-Up Integration Case would be automatically included in the SSI.
2. Develop and implement a process by which exceptions could be made to the criteria in the first step to (i) include generation or transmission not reflected in the roll-up or not automatically included and (ii) exclude facilities automatically included.

The criteria utilized by the SSC for inclusion in the model were:

- All generation and transmission that were due to be in-service prior to January 1, 2016 were automatically included.
- All transmission to be operated at a voltage level less than 230kV and with an in-service date inclusively between the years 2016 and 2020 were automatically included.
- All generation currently under construction with an in-service date inclusively between the years 2016 and 2020 were included.

EISPC's review of the Roll-up (in compliance with EISPC's SOPO Task 3) and adjustment process followed very similar criteria to the SSC process. To address the need for an exception process to these criteria, EISPC formulated a procedure in which an exception or "challenge" could be formalized such that projects that were excluded by the criteria could be included, or, projects included by the criteria could be excluded. While this was an EISPC addendum to the SSC criteria, it should be noted that representatives of the SSC from each sector were invited to participate in the discussion of the exception process, and the SSC ultimately approved the SSI model that resulted.

In the EISPC exception process, all exceptions were presented and, if not adopted by unanimous consent, were voted on by EISPC. The results were then presented to the full SSC on its conference call held on January 18, 2011. The SSC reviewed the EISPC results and approved them along with one additional transmission facility. The SSC's approved baseline facilities became known as the SSI. The following information showing the formation of the SSI is found on the EIPC Web site at:

- Projected new facilities common to both the 2020 Roll-Up Integration Case model and the SSI model found at: http://eipconline.com/uploads/Stakeholder_Specified_Infrastructure_List_021811.xls.
- Projected new facilities contained in the 2020 Roll-Up Integration Case model but removed from the SSI model as a result of the EISPC exception process found at: http://eipconline.com/uploads/Stakeholder_Specified_Infrastructure_List_021811.xls.
- Projected new facilities contained in the 2020 Roll-Up Integration Case model originally removed from the SSI model but re-instated as a result of the EISPC exception process found at: http://eipconline.com/uploads/Stakeholder_Specified_Infrastructure_List_021811.xls.

The SSI model was prepared solely for the analyses to be performed within this DOE project and has not been subjected to either a reliability evaluation or the regional planning processes provided for in FERC Order 890 and therefore should not be used for any other purpose.

The SSI model differs in many respects from the 2020 Roll-Up Integration Case model in that many of the additional generating resources and transmission facilities that were included in the 2020 Roll-Up Integration Case model were removed from the model in accordance with the stakeholder exclusion/inclusion criteria.

When the inclusion/exclusion outcome of projected generating resources and transmission facilities for the SSI model had been determined according to the SSC criteria, the power flow model was then modified and tested for its ability to reach a load flow solution[12] and was used in the remaining portion of Task 2 and in subsequent tasks within the project. This model was not tested to determine if it met the planning standards or criteria of any of the Planning Coordinators' FERC Order 890 processes.

2.2.3 Transmission Limits To Be Used in Task 5 Work

To complete Task 5, specific transfer limits between regions to be used by CRA in its NEEM model were developed. Determination of the transfer limits for the analysis (using CRA's MRN-NEEM model – see Task 5 and MRN-NEEM Modeling Assumptions and Data Sources found at: http://eipconline.com/uploads/MRN-NEEM_Draft_10-26-10.pdf for a description of this model) required identification of the "pipes" and "bubbles" that would be in the model. In the NEEM model, the North American interconnected power system is modeled as a set of regions connected to each other by a network of interregional transmission paths/transfer limits. The set of regions, their connectivity and transfer limits are user-defined inputs. Figure 5 is a diagram of the regions that were used for this assessment. These regions are the regions originally contained in the NEEM model with the exceptions that some of the regions were combined, particularly in the New York area, and the Hydro Quebec (HQ) area. Maritime regions were added because the NEEM model does not include those regions.

[12] A 500 kV HVDC line in the Manitoba area was re-instated in the model to facilitate solution of the case.

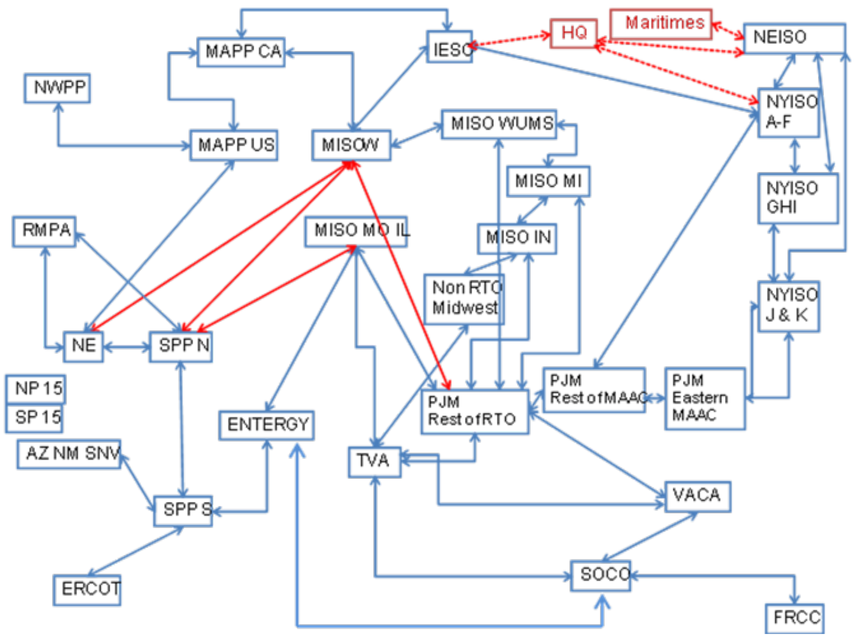

Figure 5: NEEM Regions and Transfer Limits

The NEEM limits are reliability limits that were developed using the stakeholder developed SSI model, the 2020 Roll-Up Integration Case model developed by the Planning Coordinators for the Eastern Interconnection, historical transfer limits, and analysis completed by the Planning Coordinators. Where transfer limits were needed, the involved Planning Coordinators collaborated on the approach and the choice of number used in NEEM.[13] The description of how each Planning Coordinator determined their particular limits is contained in the following file, NEEM Transfer Limits Input Descriptions FINAL 2-5-11 found at: http://eipconline.com/uploads/NEEM_Transfer_Limits_Input_Descriptions_FINAL_2-5-11.xlsx.

In addition to the regions shown in Figure 5, for some futures the regions were grouped into "super regions." These super regions were used in the regional futures (Future 3: National Carbon Constraint – Regional Implementation and Future 6: National Renewable Portfolio Standard – Regional Implementation) and the transfer limits between the super regions were not allowed to increase in those regional futures. The implications of this modeling design are further described under Task 5.

[13] The transfer limit values for the Stakeholder Specified Infrastructure model can be found at: http://www.eipconline.com/uploads/NEEM_Transfer_Limits_Input_Matrix_FINAL_2-4-11.xlsx.

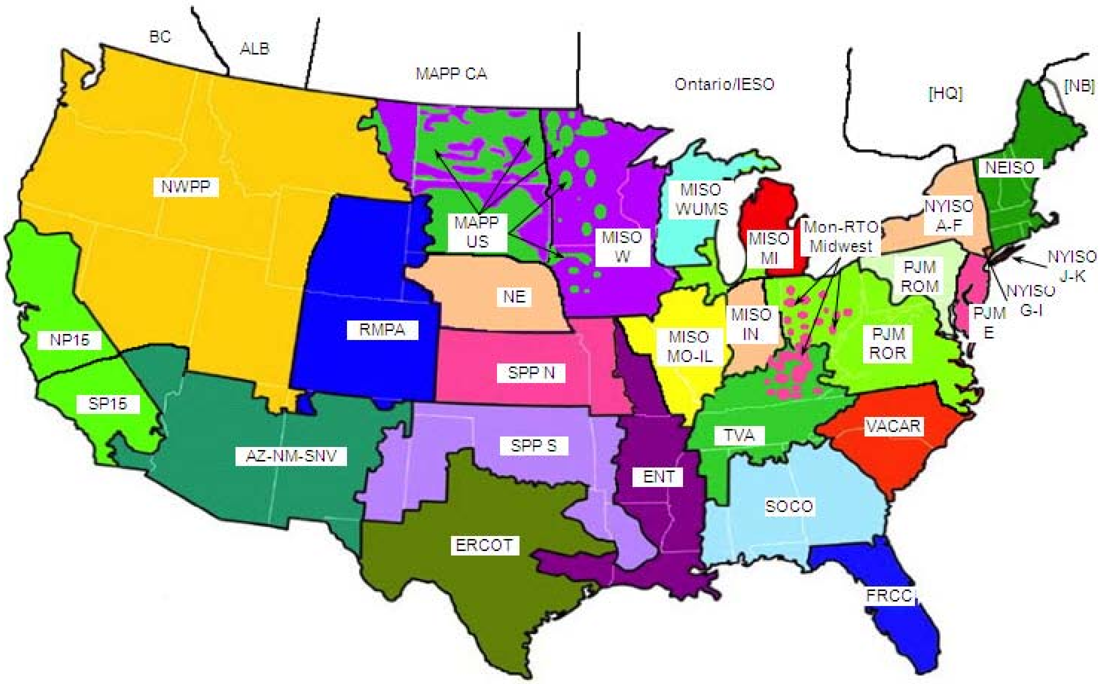

Figure 6: NEEM Geographic Regions

HQ and Maritimes are not represented by economic and power sector models in MRN-NEEM; therefore, the generating resources in those regions were modeled as "pseudo-generators." These pseudo-generation models were used to represent expansion in those regions that would be exported to other NEEM-represented regions.

As mentioned earlier in this section, the interregional transfer limits in NEEM are reliability limits, not the actual capacity of transmission projects. When these limits are expanded via the analysis described in this report, the actual transmission capacity of projects will be much greater than the power transfer capability due to reliability constraints and parallel loop flows inherent in networked alternating current (AC) systems.

2.3 Task 3 – Production Cost Analysis of Regional Plans

The project SOPO initially called for economic analysis of the integrated regional plans using production cost modeling. The production cost analysis would assess all hours of the future year and would forecast energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent information. In addition, the production cost analysis would use a model that simulates the hour-by-hour operation of the transmission and generation system in the Eastern Interconnection, incorporating transmission reliability and environmental considerations. One of the key inputs for Task 3 was to include the results from Task 2 development of the Eastern Interconnection-wide model based on integration (roll-up) of the existing regional plans. The subtasks defined in the SOPO for Task 3 were:

Subtask 3.A – Perform production cost modeling for the Roll-up Integration Case.
Subtask 3.B – Document and communicate results of production cost modeling and post the analysis on the EIPC Web site.

As the initial work on Task 3 began, EIPC concluded that the results from the analysis contemplated would be less valuable due to the changed direction of the SSC regarding the analysis and its decision to use the SSI model rather than the 2020 Roll-Up Integration Case model and the starting point for such analysis. On that basis, PJM approached DOE with a recommendation to eliminate Task 3 and re-allocate the related resources to other tasks, most notably Tasks 4 and 5. DOE agreed with this modification and issued a revised SOPO acknowledging the change.

2.4 Task 4 –Macroeconomic Futures Definition

The Statement of Project Objectives provides the following subtasks regarding macroeconomic futures definition within Task 4:

Subtask 4.A – Complete initial macroeconomic sensitivities definitions.
Subtask 4.B – Coordinate and conduct initial stakeholder regional meeting(s) to develop consensus on resource expansion scenarios.

2.4.1 Futures Definitions

The principal task of the SPWG was to agree upon and develop narratives of eight futures and the sensitivities that would go with each future. The futures were designed to be significantly different from each other and accordingly had multiple differences in their input assumptions, constraints, and objectives. In contrast, the sensitivities were designed to comprise only one change to an input assumption from the base future to which it was associated. This approach allowed the stakeholders to attribute the difference in results to the single change in the input assumptions. Following SSC approval, these eight futures were then passed on to the MWG which would develop the representative data inputs for the CRA model for each future and sensitivity.

2.4.1.1 *Coordination with Modeling Work Group*

The SPWG began coordination with the MWG early in the process of developing recommended futures to ensure that the MWG would have a good understanding of the futures being developed. The MWG was responsible for developing the detailed quantitative inputs to the CRA MRN-NEEM models that would reflect the futures and sensitivities. The SPWG and the MWG held joint meetings in the fall of 2010 to discuss the futures, sensitivities and the input data that would be used. These efforts are described in more detail in the Modeling Work Group section below in Section 2.4.3.

2.4.1.2 *Coordination with EISPC*

Throughout the process, the SPWG coordinated closely with the EISPC. While EISPC originally had the option to select four of the eight macroeconomic futures, the SPWG and EISPC instead made joint recommendations to the SSC regarding the eight futures and the 72 related sensitivities. This is but one example of the collaborative efforts of EISPC and the SSC during this project to date.

2.4.1.3 *Futures Development*

The SPWG began working in August of 2010. Initial discussions included the process by which the group would develop the futures. Different processes were discussed including:

- Building futures from the bottom up ("Deloitte" approach)
    - Identifying four to five key drivers of transmission development
    - Developing ranges of plausible outcomes for those drivers
    - Combining those drivers into plausible and internally consistent futures
    - Testing the futures to ensure they cover a full range of plausible futures
- Shell approach
    - Identifying focal question
    - Identifying two key drivers of the question
    - Building 2x2 matrix resulting in four futures
- Building off existing futures
    - Locating and reviewing existing futures that have been developed by others; e.g., Western Electricity Coordinating Council futures
    - Customizing those futures for this application
- Hybrid approach
    - Identifying key drivers
    - Identifying futures ideas
    - Iterating between driver discussions and futures discussions until futures began to emerge

There was discussion of the criteria for choosing futures. Some suggestions were:

- Diversity in forecasts/outcomes (e.g., not just a "green" future).
- Diversity in key drivers.
- Diversity in transmission outcomes.
- Diversity in policy drivers/outcomes.
- Plausibility (affordability, consumer acceptance).
- Ease of communicating the results.
- Time commitment required.
- Likelihood of achieving consensus with method.

- Whether "single bullet" futures should be included or combined with other policies to form a future.

Ultimately, the SPWG decided to take the hybrid approach described above. The SPWG began to brainstorm drivers and futures in September 2010, met face-to-face in early October 2010, and had subsequent conference calls. The SPWG reviewed drivers and futures that had already been developed and added futures ideas. These futures ideas were grouped and prioritized, and the SPWG split into smaller groups to develop the futures ideas more fully. Futures ideas ultimately included:

- Business as usual.
- Carbon capture.
- National Renewable Portfolio Standard (RPS).
- Nuclear resurgence.
- Transportation electrification.
- Aggressive energy efficiency (EE).
- Distributed generation (DG).
- Canadian imports.
- Commercial storage.
- High coal retirements.
- Regional implementation of RPS and carbon capture.
- National RPS with imported hydroelectric.
- Rapid technology development and offshore wind.
- Shale gas works including low-cost natural gas, high availability.
- Balanced/diversified/economic fuel mix including regional RPS and EE/demand response (DR) proliferation and DG and storage.
- Commercial storage with aggressive EE/DR/smart grid combined with national RPS.
- Aggressive EE/DR/smart grid and accelerated penetration of small DG near customer load.
- Nuclear resurgence and regional implementation of RPS and carbon reductions with increased imports of Canadian low carbon power.
- National RPS with accelerated retirements and no new builds of coal plus transportations electrification.
- Carbon constrained with national RPS with nuclear resurgence and increased Canadian low carbon power.
- BAU enhanced roll-up.
- Enhanced storage future.
- Increased consumer awareness.
- Significant increase in interregional transfer capacity.
- Multiple policy future.
- New storage capacity development.
- Transmission "light."

- Path to 80% reduction in carbon emissions by 2030.

Key drivers were identified that were considered important for all futures. These key drivers included:

- Policy goals of the future.
- Policy implementation approach.
- Economic performance.
- Load growth.
- Technology performance.
- Fuel prices and availability.

A template was developed that identified the central future idea, provided a more detailed narrative of the idea, identified the performance of the key drivers in the future, and provided a list of sensitivity suggestions.

The six futures presented were:

1. Business As Usual (BAU).
2. National Carbon Constraint – National Implementation.
3. National Carbon Constraint – Regional Implementation.
4. Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid.
5. National Renewable Portfolio Standard – National Implementation.
6. National Renewable Portfolio Standard – Regional Implementation.

The SPWG reached consensus on the six futures listed above but could not reach consensus on the final two futures. The SPWG and EISPC developed and presented four additional futures for consideration by the SSC. Some future ideas were combined and the concepts of "single focus" futures, which relied on a single idea or technology, were included with other futures. For example, the future ideas of consumer awareness and activism and transmission light were combined as were the mixed policy future and the 80% CO_2 reduction by 2050 future. The SPWG also took a "straw poll" of the remaining futures. These futures are presented here in order of the rank they received in the straw poll:

1. Nuclear Resurgence
2. Combined Federal Climate and Energy Policy
3. Consumer Market Awareness and Activism/Free Market/Transmission Light
4. Environmental Moderation

The SSC chose nuclear resurgence and the combined federal climate and energy policy futures as the final two to complete the package of eight futures. The SSC also decided that the consumer market awareness and activism/free market/transmission light (CMAA/FM/TL) future would be captured by defining at least two sensitivities to the BAU future that would approximate some of the conditions in CMAA/FM/TL. The SSC also decided that the environmental moderation future would be captured by using four sensitivities to the BAU future.

2.4.2 Sensitivities

As futures were developed, suggestions for possible sensitivities were also developed. Each future was originally allocated nine sensitivities. Later, it was learned that the sensitivities were interchangeable, and there was more flexibility in how to allocate the sensitivities as long as the total number of sensitivities did not exceed 72.

There was conversation within the SPWG about whether to have a core set of sensitivities that would be the same in all futures. The reason for this was to provide for more comparability among the results of the futures. Sensitivities that appear in several futures include high and low load growth and high and low natural gas prices. Ultimately, the SSC chose to have high and low load growth in several futures and to include changes in natural gas prices in several. Sometimes this meant high natural gas prices, and sometimes it meant lower natural gas prices.

The SPWG and EISPC presented a list of sensitivities to the SSC at the December 2010 meeting. There were many areas where the SPWG and EISPC agreed and some areas where the two groups differed. Decisions on some sensitivities were made at the February 2011 SSC meeting, and the results of those decisions were posted on the EIPC Web site. The SSC decided to delay choosing a few sensitivities, so decisions could be made as results became available from the initial CRA MRN-NEEM runs. The concept was to keep some sensitivities available to develop information that might be helpful in determining the three Phase 2 scenarios.

2.4.3 Data Inputs – Modeling Work Group Activities

2.4.3.1 *Modeling Work Group: Formation of Sub Teams*

For Task 4, the MWG formed several sub-teams to consult with CRA and the other SSC work groups to provide advice and recommendations on the numerous data inputs required for the MRN-NEEM model and to most effectively represent the designated futures and their respective sensitivities. These sub-teams were:

- Existing Generation.
- New Generation.
- Environmental Policy.
- Load Forecasts/Demand Response/Energy Efficiency.
- NEEM Regions/Transmission.
- Fuel Prices/Emissions.
- General Equilibrium Model Parameters/MRN Inputs.
- Canadian Parameters.

In the fall of 2010, EIPC prepared an extensive document describing the MRN-NEEM models and their operation and published a matrix containing the default data inputs and assumptions. EIPC held a series of webinars and meetings at the request of the SSC work groups to provide further explanation and to answer stakeholder questions. The MWG, working with the SPWG, submitted a series of modeling-related questions that CRA and EIPC posted responses to on the EIPC Web site. As a result of these activities, the MWG became more familiar with the models and input requirements and, through their sub-teams, began further exploration into certain key areas that were needed to model the energy futures under development by the SPWG and the SSC. Additional information on the MRN-NEEM models is provided on the EIPC Web site at: http://www.eipconline.com/Resource_Library.html.

2.4.3.2 *SSC Interaction with the Modeling Work Group*

The SSC reviewed the work of the MWG in several face-to-face meetings and in conference calls and webinars beginning in January 2011 and continuing until fall 2011. The MWG began with the BAU future and obtained SSC approval for a majority of the assumptions during the SSC's February 2011 meeting. This allowed CRA to begin model development. The SSC provided feedback either agreeing with the MWG recommendations or asking the group to refine some recommendations.

As CRA completed modeling futures, they presented the results to the SSC for review. The initial BAU future results were presented in March 2011. At that time, the SSC asked the MWG to revisit the environmental assumptions because EPA had issued rules relating to certain programs that were significantly different than had been anticipated. Natural gas costs were also a significant issue for the SSC as some stakeholders wanted to ensure that lower natural gas costs were included and some requested extra high natural gas costs.

In March 2011, the MWG presented consensus recommendations on the vast majority of inputs needed for all futures and many of the sensitivities. Where there was no consensus, the MWG presented options for consideration by the SSC. Some of these non-consensus areas included plug-in hybrid electric vehicle (PHEV) levels, friction charges (as defined in section 2.4.3.8 NEEM Region/Transmission), and offshore wind incentives. The SSC reviewed all items and made decisions on both the consensus recommendations and the non-consensus items, and identified remaining questions and decisions.

In subsequent SSC meetings, CRA presented results of the model runs that had been completed, and the results were reviewed and discussed including apparent anomalies in the results. The MWG presented three transfer limit hardening approaches to the SSC to be used in establishing changes to pipe transfer limits as a result of the “soft constraint methodology” sensitivities for certain futures. The SSC ultimately decided to use an average of all three approaches going forward. For information on the soft constraint methodology and the transfer limit hardening process, see sections 2.4.4 and 2.5.2.2 as well as Appendices 3 and 4; respectively.

Overall a significant amount of work was done by the MWG, reviewed and approved by the SSC, and consensus was ultimately reached on all the inputs to the models. There were many in-depth, detailed discussions by the group as they worked to understand the issues and their implications and mad an informed decision. For more detailed explanations of the issues and resolutions, refer to the EIPC Web site (http://www.eipconline.com/), SSC page, particularly the meeting memos and summaries from February through May 2011.

2.4.3.3 *Key Input Data Assumptions*

The input data assumptions for the CRA models were reviewed and investigated by the appropriate MWG sub-teams, which then provided their recommendations to the MWG and ultimately to the SSC for decision.

2.4.3.4 *Existing Generation Sub-Team*

In response to EIPC's explanation that the source for existing generation in the NEEM model is from the Ventyx "Energy Velocity" database and that these units are then aggregated by type, size, heat rate, etc. in their models, the MWG expressed a desire to verify that input data. Accordingly, CRA organized a webinar with several sub-team members who were also licensed for access to the Ventyx database for this purpose. Ultimately, the SSC agreed to use the Ventyx database for existing generating units.

2.4.3.5 *New Generation Sub-Team*

The default source for new generation information was DOE's Energy Information Administration's Annual Energy Outlook (AEO) 2010 report. At the time, the AEO 2011 data was to be issued shortly and could be utilized to update the NEEM inputs. The sub-team spent a great deal of time exploring various data sources for capital cost and operating characteristics of new units with a focus on wind generation and to a lesser extent, new nuclear and coal technologies. The sub-team also reviewed the AEO assumptions for transmission interconnection costs, and the SSC agreed to use a uniform transmission interconnection cost for all technologies and to use the AEO 2011 as the source for the cost of new generating capacity for all of the technologies in the model. Generation technologies that were not previously available as options in NEEM's capacity expansion such as hydrokinetic, energy storage[14], and natural gas combined cycle (NGCC) with carbon capture and storage (CCS) could not be added. This sub-team also reviewed wind generation output shape data from various sources and recommended what to use in the NEEM models. Finally, this sub-team also devoted significant efforts to establishing recommendations for the inputs related to wind generation; e.g., capacity factor, resource potential, contribution to planning reserves, and penetration rate limits. Although the factors that impact integration cost and curtailment rate

[14] Existing pumped hydroelectric storage (PHS) was included in the model, but new storage capacity and non-PHS technologies were not available as options in the capacity expansion.

(interconnection costs, system flexibility, etc.) could not be directly captured, the penetration level of variable generation from wind and solar was capped at a fixed percentage of the total load in an given intermittency region to ensure the plausibility of modeling results. The definition of these intermittency regions is discussed below in Section 2.5.1.2. The learning rate assumptions for generation technologies were also based to a large extent on AEO 2011 assumptions, but these were applied as external cost reductions independent of deployment rate. The SSC ultimately approved the characteristics to be utilized for the various NEEM regions relying primarily upon the recommendations from the Planning Coordinators for their respective regions, especially for inputs related to system reliability such as renewable resource contribution to reserve margins.

2.4.3.6 *Environmental Issues Sub-Team*

The sub-team reviewed and developed inputs related to EPA regulations, national and state RPS policies, and carbon policies. For state RPS policies, the sub-team, in conjunction with CRA and state stakeholders, aggregated information on state RPS policies and merged it into modeling tools applied to each NEEM region. National and regional RPS policies used in Futures 5, 6, and 8 were modeled according to scenario design.

The sub-team devoted efforts to the modeling for the EPA non-carbon regulations and, through discussions with CRA, arrived at a recommended methodology that was approved by the SSC and used in the first three sensitivities of the BAU. Shortly after the initial three BAU sensitivities were run, the EPA issued proposed air and water regulations that were significantly different from previous expectations. Accordingly, the SSC directed the MWG to work with EIPC and the EPA to modify the initial assumptions to more accurately reflect the new proposed regulations. That was completed, and the new methodology was approved by the SSC for use in all of the remaining futures and sensitivities as appropriate.

The sub-team also explored in detail the modeling to be used to represent a national carbon policy. Based on EIPC recommendations for the MRN-NEEM model, the sub-team recommended, and the SSC approved, the use of a carbon tax to achieve the targeted reductions of 42% in carbon emissions in 2030 and 80% in 2050 in Futures 2, 3, and 8. EIPC gave CRA the flexibility to iterate their models to determine the carbon tax needed to reach these target levels as closely as possible.

The sub-team also reviewed modeling assumptions for the Northeast and Mid-Atlantic states' Regional Greenhouse Gas Initiative (RGGI) regions.

2.4.3.7 *Load Forecast/Demand Response/Energy Efficiency Sub-Team*

The sub-team reviewed the load forecast assumptions provided by the EIPC Planning Coordinators in the 2020 Roll-Up Integration Case, including the demand response and energy efficiency assumptions. Because the demand response, energy efficiency, and distributed generation could not be chosen internally by the model, the deployment levels of these resources were specified external to the model by the stakeholders. The default assumptions were also reviewed and EISPC provided detailed information on the states' demand response/energy efficiency goals for consideration. Because load growth and economic output are directly coupled in MRN through the autonomous energy efficiency improvement (AEEI) parameter, the equilibration between MRN and NEEM, as discussed in Section 2.5, was not performed in Futures 4 and 8 where the deployment of energy efficiency exceeded BAU levels. In these futures, the MRN outputs were frozen at the analogous low-energy efficiency Futures 1 and 2, respectively, so that demand-side resources would not be mischaracterized as reductions in gross domestic product (GDP).

2.4.3.8 *NEEM Regions/Transmission Sub-Team*

The sub-team initially reviewed the revised NEEM regions and transfer limits provided by the Planning Coordinators for the models. As a result of discussions with the Planning Coordinators, several modifications were made. The Planning Coordinators also provided the sub-team with the wheeling charges representing each region's point-to-point rate for "out" transactions and friction hurdle rates representing economic inefficiency of trading across the seam between two markets with imperfect knowledge. These wheeling charges and friction hurdle rates were reviewed and discussed within the sub-team. The Planning Coordinators' inputs were ultimately adopted by the SSC.

This sub-team worked with EIPC and northeastern stakeholders to develop a method to represent Maritime and HQ resources in the adjacent NEEM bubbles, see Appendix 5 - Modeling Electricity Flows from HQ and the Maritimes. The sub-team also developed recommendations on how to differentiate regional and national implementation of public policy futures such as a renewable portfolio standard.

A major effort of this sub-team was devoted to exploring the soft constraint methodology proposed by EIPC to address the transmission expansion issue for Task 5. Initially it was envisioned that the soft constraint methodology would be used for many sensitivities; however, the stakeholders instead wanted to use information from the soft constraint methodology to set fixed pipe sizes. The follow-on work for the sub-team was to develop a methodology for analyzing the soft constraint output data in order to determine the "hard transfer limits" to apply to select futures. Additional information on the soft constraint methodology is provided in sections 2.5.2.2 and 2.5.2.3 and in Appendix 3.

Finally, the sub-team reviewed the high-level transmission cost methodology developed by the Planning Coordinators for application in Task 5.

2.4.3.9 *Fuel Prices/Emissions Sub-Team*

This sub-team focused on coal and natural gas prices. The MRN model derives coal prices for use in the NEEM model based upon economic parameters. The sub-team recommended, and the SSC agreed, to utilize this feature for the studies. Natural gas prices were a major focus of the sub-team's efforts since it was anticipated that this would be a significant driver of the resource expansions for many of the futures. After considerable debate and analysis by the sub-team, the SSC agreed to use the AEO 2011 gas prices as the base assumption and a hybrid of AEO 2010 and 2011, developed by this sub-team, for the high gas price sensitivities.

2.4.3.10 *General Equilibrium Model Parameters/MRN Inputs Sub-Team*

The sub-team focused on a review of the economic assumptions utilized in the MRN model and how they interact with other parts of the models. The factors reviewed by the sub-team included discount rate, GDP deflators, coefficients of elasticity and substitution factors as well as tax rates. The sub-team also reviewed how the assumptions for balanced budgets, labor, and GDP were developed by the models. The SSC agreed to utilize the CRA's default assumptions for these factors.

2.4.3.11 *Canadian Parameters Sub-Team*

The sub-team provided input data for several Canadian regions regarding such factors as load forecasts and shape, wind output, and other economic parameters. This sub-team was also instrumental in providing data on new generation expansion plans for the Canadian regions and, in consultation with the NEEM Regions/Transmission Sub-Team, modeling cross-border hydroelectric transactions into the northeastern U.S. regions.

2.4.4 Transmission – The "Soft Constraint Methodology"

The MRN-NEEM models utilized for the Task 5 analysis are primarily resource expansion models which represent transmission through the use of transfer limits between the various regions or bubbles included in the model. These models do not explicitly model the transmission system or include transmission capital costs. To address stakeholder questions and their desire to have more information regarding the potential transmission implications of the various resource futures as input into their determination of the final three scenarios for detailed analysis in Phase 2 of the project, EIPC developed the "soft constraint methodology." In brief, this methodology was designed to provide information to stakeholders regarding the most likely locations for potential increases in transfer limits based upon the economic signals, or shadow prices, provided as outputs from the NEEM model. Following several presentations and stakeholder discussions, it was agreed that EIPC would implement this methodology for the Task 5 analysis. For each of the eight futures, the SSC would determine whether to utilize one or more sensitivities under the soft constraint methodology and the SSC would then make a subsequent determination whether to utilize increased transfer limits for the remaining sensitivities within that future based upon that information. Additional information on the soft constraint methodology is provided under Task 5 and in Appendix 3 of this report.

Finally, as described in more detail under Task 5, the NEEM Regions/Transmission Sub-Team developed a methodology for SSC approval to analyze the soft constraint data to determine the increased hard transfer limits to apply to subsequent sensitivities. The Planning Coordinators then developed a procedure to provide high-level estimates of transmission facilities and costs to approximate those increased transfer limits.

2.4.5 Final Eight Futures

Future 1: Business as Usual. Continuation of existing conditions including load growth, existing Renewable Portfolio Standards (RPSs), and currently proposed environmental regulations.

Future 2: National Carbon Constraint – National Implementation. Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy.

Future 3: National Carbon Constraint – Regional Implementation. Reduce economy-wide carbon emissions by 42% from 2005 levels in 2030 and 80% in 2050; achieved by utilizing a regional implementation strategy.

Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid. Aggressive implementation of energy efficiency (EE), demand response (DR), distributed generation (DG) and smart grid technology resulting in decline in load from today's levels.

Future 5: National Renewable Portfolio Standard – National Implementation. Meet 30% of the nation's electricity requirements from renewable resources by 2030; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy.

Future 6: National Renewable Portfolio Standard – Regional Implementation. Meet 30% of the nation's electricity requirements from renewable resources by 2030; achieved by utilizing a regional implementation strategy.

Future 7: Nuclear Resurgence. Significant nuclear facilities developed in Eastern Interconnection.

Future 8: Combined Federal Climate and Energy Policy. Reduce economy-wide carbon emissions by 50% from 2005 levels in 2030 and 80% in 2050 combined with meeting 30% of the nation's electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, demand response, distributed generation, smart grid and other low-carbon technologies; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy.

Ultimately, EISPC (in compliance with EISPC's SOPO Task 6) and the SSC agreed, by consensus, to these futures. In addition, EISPC representatives serving with the MWG formed "sub-teams" to develop the required data inputs for the MRN/NEEM model.

2.5 Task 5 – Macroeconomic Analysis

As discussed in Task 4, stakeholders developed eight futures and 72 sensitivities, for a total of 80 model runs to be analyzed in Task 5 using macroeconomic modeling. Models were used in Task 5 to project the electricity generation expansion and corresponding electricity flows that would take place in the Eastern Interconnection under each sensitivity. To perform this analysis, the MRN-NEEM modeling framework described below was used.

2.5.1 MRN-NEEM Model Overview

The MRN-NEEM model combines two state-of-the-art economic models: the Multi-Region National (MRN) model and the North American Electricity and Environment Model (NEEM). This integrated modeling approach provides a framework for examining electricity sector specific impacts in detail while also reflecting the economy-wide impacts of specific climate policies. An MRN-NEEM solution is a general equilibrium solution, meaning that all markets in the economy are at equilibrium. See MRN-NEEM Modeling Assumptions and Data Sources, found at: http://eipconline.com/uploads/MRN-NEEM_Draft_10-26-10.pdf, for a more detailed description of the MRN-NEEM model.

The primary reason that a general equilibrium solution is desirable in assessing energy markets is that significant policies; e.g., carbon policies; can affect energy demand growth and relative fuel prices. Because energy is an input to most products in the economy, a carbon policy ripples through the entire economy affecting relative prices. NEEM is strictly a model of the electric sector, so it cannot assess these macroeconomic dynamics for a particular future when run as a stand-alone model. Since running the MRN-NEEM model involves running NEEM and MRN in succession until convergence is achieved between the two models, it is helpful to conceptualize and discuss the models separately.

2.5.1.1 *MRN Model*

The top-down component of the integrated MRN-NEEM model is tailored from the Multi-Region National (MRN) model. MRN is a forward-looking, dynamic computable general equilibrium (CGE) model of the United States. It is based on the theoretical concept of an equilibrium in which macro-level outcomes are driven by the decisions of self-interested consumers and producers. The basic structure of CGE models, such as MRN, is built around a circular flow of goods and payments between households, firms, and the government, as illustrated in Figure 7.

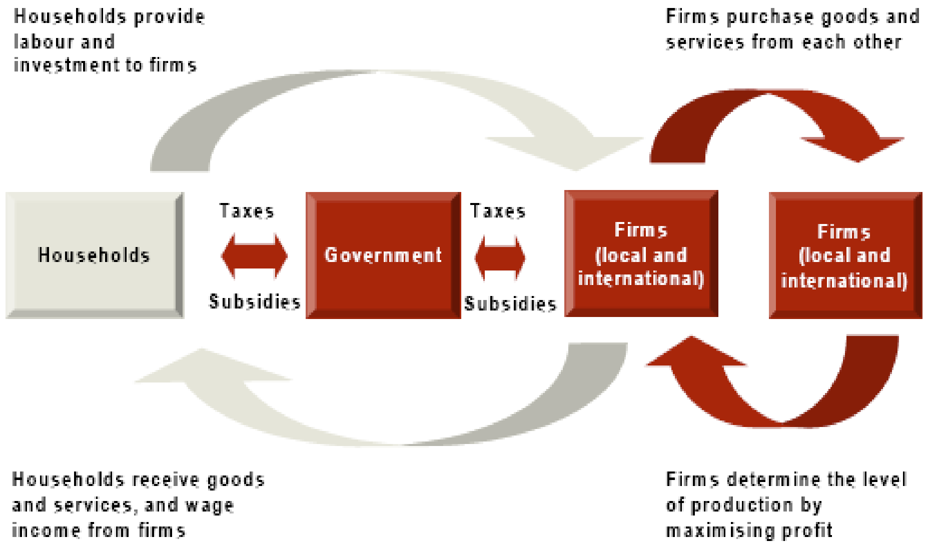

Figure 7: Circular Flow of Goods and Services and Payment

2.5.1.2 *NEEM Model*

The NEEM is a flexible, partial equilibrium model of the North American electricity sector that can simultaneously model both system expansion and environmental compliance over a 30- to 50-year timeframe.

NEEM was developed to analyze the impact of environmental policy and major economic drivers on the electricity sector. The model calculates the "least-cost solution" to serve load, while complying with environmental policies and meeting resource adequacy requirements and major transmission constraints.

NEEM can be used to model both regional and national environmental policies including direct taxes on emissions, emission caps, command-and-control policies, as well as renewable portfolio standards (RPSs). In addition to forecasting zonal electricity and emissions prices, NEEM optimizes retirements, environmental retrofits, and construction of generating capacity.

The model employs detailed unit-level information on all of the generating units in the United States and large portions of Canada. In general, coal units of 200 MW or greater are represented individually in the model, and other unit types are aggregated within each NEEM region. NEEM models the evolution of the North American power system taking into account demand growth, currently installed generation, future available generation technologies, pollution control technologies, and environmental regulations both present and future.

The North American interconnected power system is modeled as a set of regions referred to as NEEM regions that are connected by a network of transmission paths. NEEM regions are shown in Figure 8. This paradigm is also referred to as a "transport model" or a pipes-and-bubbles model. Transfer limits are specified between the NEEM regions. NEEM is a load-duration curve model, with 20 load blocks totaling to 8,760 hours modeled in each year.

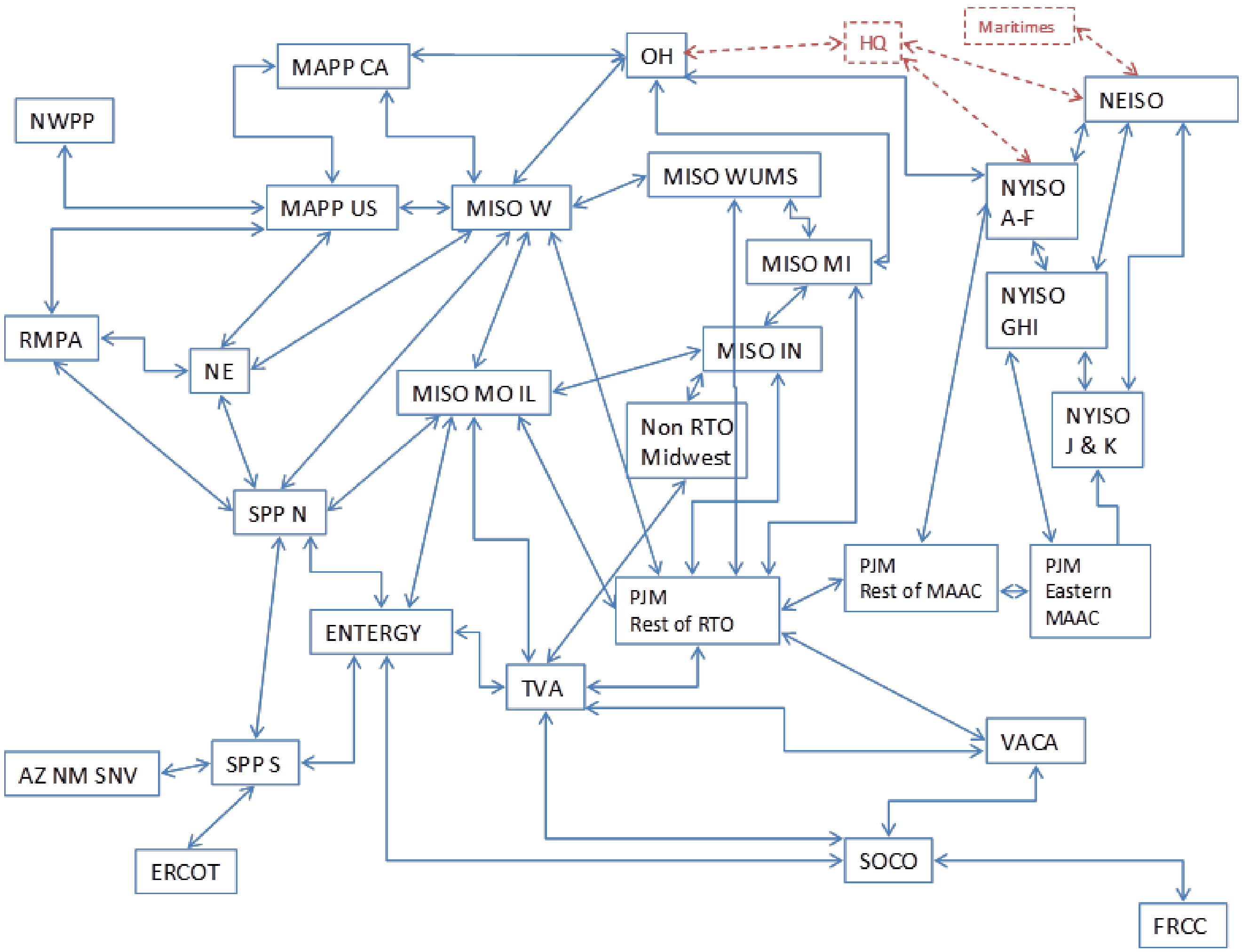

Figure 8: NEEM Regions

2.5.1.3 *MRN-NEEM Integration Methodology*

The MRN-NEEM integration methodology follows an iterative procedure to link the top-down and bottom-up models. The method utilizes an iterative process where the MRN and NEEM models are solved in succession, reconciling the equilibrium prices and quantities between the two models. The solution procedure, in general, involves an iterative solution of the top-down general equilibrium model (MRN) given the net supplies from the bottom-up electric sector sub-model (NEEM), followed by the solution of the electric sector model (NEEM). The two models are solved independently using different solution techniques but are integrated through iterative solution points. To speed solution times, the models are solved for every fifth modeling year; e.g., 2015, 2020, 2025.

In addition to the NEEM Regions discussed in Section 2.5.1.2, for some futures the regions were grouped into “super regions.” These super regions, as shown in Figure 9, were used in the regional implementation futures, Future 3: National Carbon Constraint – Regional Implementation and Future 6: National Renewable Portfolio Standard – Regional Implementation, as a means to represent a regional, rather than national, approach to implement the policy mechanisms that defined those futures. To implement the regional approach in the model, the transfer limits between the super regions were not allowed to expand in those regional futures.

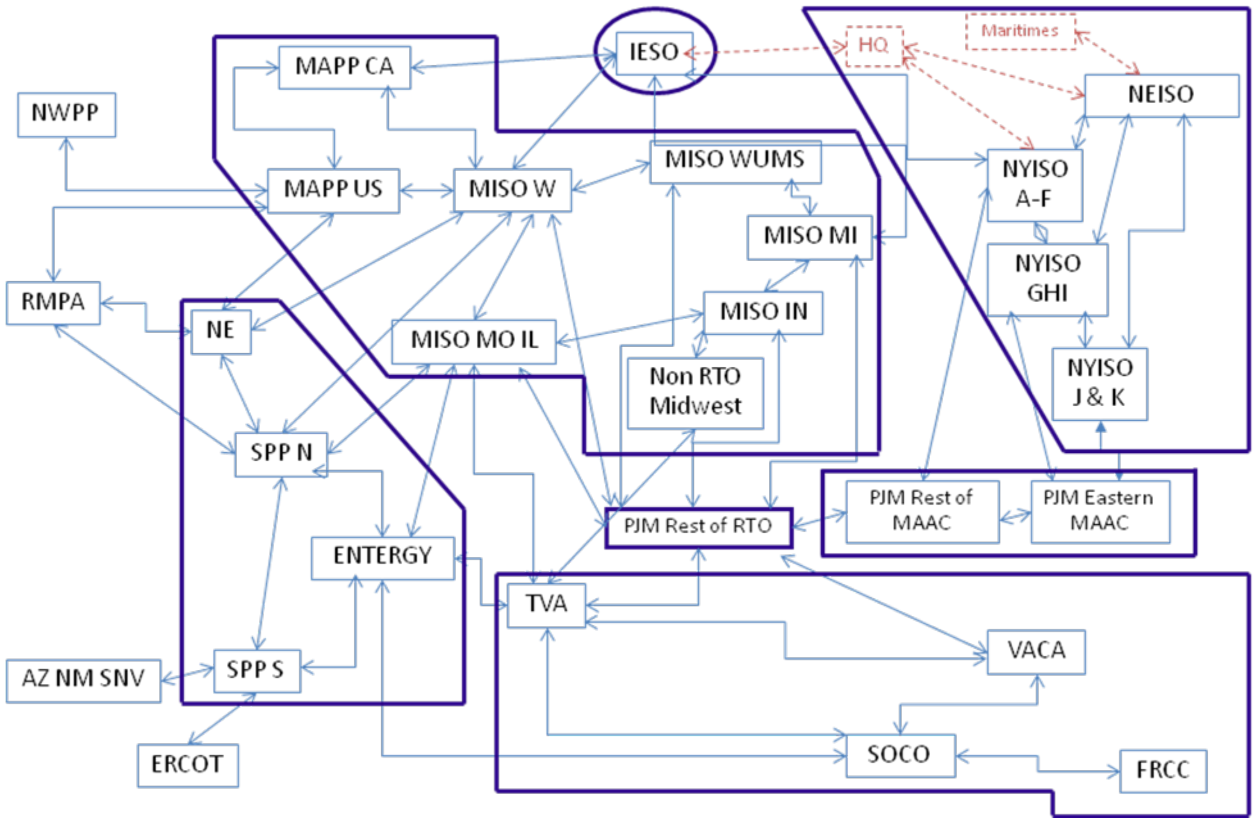

Figure 9: NEEM Super Regions

In all of the futures, the regions were also grouped into “intermittency regions." The intermittency region concept was intended to represent the geographic area within which the intermittent output from certain generation resources could be shared, and it formed the geographic basis for imposing an upper bound on the penetration rate for variable energy resources (VERs) such as wind and solar. The model capped the generation from these resources at a specific fraction of the load in a given intermittency region, thereby providing a proxy for the interregional coordination that can facilitate VER integration by leveraging geographic diversity of the resource. The NEEM regions that comprised the intermittency regions differed depending upon whether the future was a national or regional policy implementation future. National policy implementation futures had four, larger intermittency regions, while the regional policy implementation futures had seven, smaller intermittency regions, consistent the grouping of super regions. For Futures 1, 4, and 7 which were neither specifically national or regional, the intermittency regions were congruent with the NEEM regions.

2.5.2 Modeling Methodology

Using the stakeholder-approved input assumptions described in Task 4, MRN-NEEM model runs were completed for each of the futures and sensitivities using the following modeling steps.[15]

2.5.2.1 *Macroeconomic Baseline for Each Future*

The integrated MRN-NEEM model was used to maintain macroeconomic consistency among eight futures. For the initial model run, or base case of each future, the key modeling steps were as follows:

1. Future 1: Business As Usual input assumptions were developed by the stakeholders to apply in the MRN-NEEM model (see Task 4). The intent was to use the Business As Usual future as the starting point for all other futures.
2. For Future 1: Business As Usual, the MRN-NEEM model was calibrated to yield a macroeconomic baseline, or base case, based largely on the AEO 2011 (Early Release), modified by stakeholders with respect to certain electricity sector assumptions; e.g., electricity demand and natural gas prices. The base case generation expansion results for this future are from the NEEM output from this MRN-NEEM model run.[16]
3. Using Future 1 as a starting point for each subsequent future, changes to the MRN-NEEM input assumptions were then made for a specific future in accordance with that future's definition.
4. A new MRN-NEEM model run was then performed to establish the macroeconomic baseline, or base case, for that future, including GDP, electricity demand and natural gas prices, along with capacity expansion in the electricity sector.[17] The base case generation expansion results for the future are from the NEEM output from this MRN-NEEM model run.

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[15] See http://eipconline.com/uploads/MRN-NEEM_Draft_10-26-10.pdf for a description of the modeling input assumptions used in all of the futures and sensitivities. The Task 5 results presented herein use modeling assumptions developed by EIPC, stakeholders, and CRA in Task 4 for purposes of EIPC capacity expansion modeling. As such, these results do not necessarily reflect the opinions or views of CRA or any individual stakeholder.

[16] As noted in the Task 4 summary, modified EPA regulations were incorporated into the Future 1 Base Case to establish a new Base Case from which all subsequent futures and sensitivities were developed. This case, Future 1 - Sensitivity 3 (later further refined in Future 1 - Sensitivity 17), served as the baseline for comparing all subsequent case results.

[17] Per stakeholder decisions, Futures 2 and 3 were based on the same MRN-NEEM macroeconomic baseline as were Futures 5 and 6. Future 1 was used as the macroeconomic baseline for Future 4, and Future 2 was used as the macroeconomic baseline for Future 8. For these pairs of futures, differences in results for the Base Case of that future result solely from differences in NEEM input assumptions regarding the electric sector.

2.5.2.2 *Sensitivities for Each Future*

The sensitivity cases for each future used the MRN-NEEM Base Case as the starting point for that future. Changes in input assumptions from the Base Case, for example high load, were then run through the NEEM model on a stand-alone basis to capture the impact of the sensitivity on the electric sector. For most futures, soft constraint sensitivities were first conducted in NEEM to help stakeholders assess the amount of transfer path expansion between NEEM regions in the Eastern Interconnection that might be economic for the future.

Using the stakeholder-developed transfer limit expansions between Eastern Interconnection NEEM regions derived from the soft-constraint sensitivities, the remaining additional sensitivities were then conducted for each future. In most futures, this included evaluating the impact of increasing the transfer limits as a "hardened limit" sensitivity case.[18]

Initially the model was run with the transfer limits developed by the Planning Coordinators. This was referred to as the base run. Then a sensitivity used to test expansion of the transfer limits was run, referred to as the soft constraint run. In the soft constraint methodology, developed by CRA and EIPC and approved by the SSC, an additional overload pipe is added to a constraint in addition to the baseline pipe. The overload pipe has unlimited transfer capacity subject to a wheeling charge (overload charge) set proportional to the shadow prices in the baseline run of the model. The NEEM model would first choose to utilize the baseline pipe as there was no overload charge applied for the use of that pipe. Then, to the extent economically justified, NEEM would use the overload pipe for any further desired energy transfers. See http://www.eipconline.com/uploads/Transmission_in_MRN-NEEM_New_FINAL_12-30-10.pdf for a presentation on an early version of the soft constraint methodology. The SSC agreed to set the overload charge for each constraint to either 75% (OL75) or 25% (OL25) of the average base run shadow prices for that constraint; the greater the reduction of the shadow price, the greater the increase in energy transfers. Once the soft constraint sensitivities were run, an analysis was needed in order to translate the soft constraint sensitivity energy transfers into new "hardened" pipes; i.e., the constrained use of unlimited capacity pipes needed to be converted to new fixed pipe sizes. These hardened pipe limits were then used in the NEEM model to run the remaining sensitivities for the particular future in question. The hardening process is described below. The SSC then determined which level of pipe sizes would be used to run the remaining sensitivities for a particular future: the original limits determined by the Planning Coordinators, the hardened limits using the 25% soft constraint run, or the hardened limits using the 75% soft constraint run.

Modeling runs were performed for the hardening sensitivities. The original intent was to proceed with the sensitivities with transfer limits selected through the soft constraint and hardened limit methodologies, which indicated the location and size of interface expansions suggested by the model. However, without performing a model run with the new transfer

[18] For Futures 1, 4, and 7, the transfer limits were not increased, thus no hardened limit sensitivity was conducted.

limits and no other changes to input assumptions, attribution of the results could not be definitively associated with the input assumption change or the new transfer limits. Accordingly, some of the budgeted sensitivities were reserved for futures in which stakeholders expanded the transfer limits. With respect to transfer limits, the following was performed for each future:

1. Base case for the future was run with the Planning Coordinator-developed transfer limits.
2. Soft constraint sensitivities were run when specified by the SSC.
3. Hardening methodology was performed on the soft constraint runs.
4. Stakeholders chose the transfer limit to be used for the remaining sensitivity runs of that future.
5. Remaining sensitivities were run with the chosen limit.

2.5.2.3 *Expansion of Transfer Limits: Stakeholder Choices and Results*

Below is a description of the soft constraint decisions for each future. The decision on which soft constraints to run and to harden was based on SSC consensus, considering such factors as ensuring a range of transmission buildout results, value of additional buildouts, and consistency between similar futures; e.g., between regional and national implementation of the same Federal policy.

- Future 1: Business As Usual – Two soft constraint sensitivities were run, one with shadow prices set to 25% of their level in the base case (OL25) and one with shadow prices set to 75% of their level in the base case (OL75). These sensitivities ultimately were not used and the transfer limits were set at the original levels determined by the Planning Coordinators because there were no significant changes in the resource mix. Setting the pipe limits to the original levels set by the Planning Coordinators means that no additional transmission is needed between the regions over and above what was included as part of the SSI model.
- Future 2: National Carbon Constraint – National Implementation – Two soft constraint sensitivities were run with shadow prices set to 75% of their level in the base case (OL75) and 25% of their level in the base case (OL25).[19] The hardened version of the OL75 result was used for the remaining sensitivities resulting in an additional 40 GW buildout of firm transmission interface capacity between regions.
- Future 3: National Carbon Constraint – Regional Implementation – One soft constraint sensitivity was run with shadow prices set to 75% of their level in the base case (OL75) to be comparable with Future 2. The hardened version of this result was used for the

[19] The SSC elected to run Futures 2 and 3 with the OL75 and Futures 5 and 6 with OL25 to observe the results and the effects on transmission expansion and high level cost estimates for two significant buildouts from two different policy drivers. Consistent soft constraint overload between Futures 2 and 3 and between Futures 5 and 6 was considered important when comparing the results of implementing a policy nationally versus regionally.

remaining sensitivities. As mentioned in Section 2.5.2.2 the pipes between super regions were not allowed to expand in this model, only pipes within the super regions were allowed to expand. This process resulted in an additional 5 GW buildout of transmission.

- Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid – No soft constraint sensitivities were run and the original transfer limits determined by the Planning Coordinators were used for the remaining sensitivities because transmission expansion was not expected due to the aggressive energy efficiency lowering load. No additional transmission buildout was specified.
- Future 5: National Renewable Portfolio Standard – National Implementation – Two soft constraint sensitivities were run with shadow prices set to 75% of their level in the base case (OL75) and 25% of their level in the base case (OL25) (see footnote 13). The hardened version of the OL25 result was used for the remaining sensitivities. This resulted in an additional 64 GW buildout of transmission.
- Future 6: National Renewable Portfolio Standard – Regional Implementation - One soft constraint sensitivity was run with shadow prices set to 25% of their level in the base case (OL25) to be comparable to Future 5. The hardened version of this result was used for the remaining sensitivities. As mentioned above the pipes between super regions were not allowed to expand in this model, only pipes within the super regions were allowed to expand. This process resulted in an additional 3 GW buildout of transmission.
- Future 7: Nuclear Resurgence – One soft constraint sensitivity was run with shadow prices set to 25% of their level in the base case (OL25). Stakeholders chose to use the base case limits for this future, resulting in no additional transmission buildout.
- Future 8: Combined Federal Climate and Energy Policy – Both the OL25 and OL75 soft constraint sensitivities were run and the stakeholders chose the OL75 run to set the hardened limits, resulting in an additional 37 GW buildout of transmission.

2.5.3 Modeling Results

The results obtained from the modeling runs will first be described from a high-level perspective. The overall effect of each future’s assumptions on generation resource capacities is compared and discussed. Following the high-level summary discussion is a summary of key findings for each future.

2.5.3.1 *High-Level Summary of Results*

Detailed model outputs (output reports) were provided to stakeholders for each of the 80 model runs analyzed, and are summarized below. The outputs were provided by modeling year (every fifth year) from 2015 through 2040 by NEEM region for the following parameters:

- New capacity builds by type.
- Capacity retirements by type.

- Generation by type of capacity.
- Emissions and emissions costs by type of capacity.
- Fuel and O&M costs by type of capacity.
- Capital costs for new capacity builds by type of capacity.
- Energy flows by transfer path.

A number of other parameters were reported as well.[20] These output reports are posted at http://www.eipconline.com/Modeling_Results.html. CRA provided an overview and interpretation of the key results for each case to the SSC on an on-going basis as the cases were analyzed. These presentations are also posted at http://www.eipconline.com/Modeling_Results.html.

2.5.3.2 *Installed Capacity in 2030*

One key output of each future/sensitivity was the amount of installed capacity in the Eastern Interconnection in service in 2030 by capacity type. These results are summarized for all future/sensitivity runs in http://www.eipconline.com/Modeling_Results.html. Table 3 shows each future's starting point results that reflect the transfer capabilities between NEEM regions upon which sensitivities were built. Results for the base case for the future are shown for Futures 1, 4 and 7 as the transfer limits between NEEM regions were not expanded in these futures. Results for the hardened limit sensitivity results are shown for Futures 2, 3, 5, 6 and 8, reflecting the expansion of transfer limits between NEEM regions selected by the SSC.

[20] See http://www.eipconline.com/uploads/EIPC_MRN-NEEM_Output_Reports_Framework_3-25-11.pdf for an overview of the information contained in the output reports. Dollar figures in the Output Reports were provided in 2010 real dollars.

Table 3: Installed 2030 Interconnection Capacity (GW) by Capacity Type for Key Starting Point Cases

		Installed Capacity in 2030							
	Total	**F1**	**F2**	**F3**	**F4**	**F5**	**F6**	**F7**	**F8**
	2010	**Base**	**Hard**	**Hard**	**Base**	**Hard**	**Hard**	**Base**	**Hard**
Coal	272	199	31	39	172	179	178	199	10
Nuclear	100	105	131	134	105	105	105	129	134
CC	133	202	226	252	138	166	157	174	208
CT	120	132	112	105	69	140	134	134	66
Steam Oil/Gas	75	36	29	18	3	38	38	34	4
Hydro	45	45	51	52	45	51	52	47	50
On-Shore Wind	19	68	317	197	54	217	159	68	261
Off-Shore Wind	0	2	2	2	2	2	38	2	2
Other Renewable	4	14	13	13	12	13	37	14	12
New HQ/Maritimes	0	0	3	5	0	6	1	0	5
Other	17	17	17	17	17	17	17	17	17
Total w/o DR	783	818	932	833	617	933	916	818	770
DR	33	71	71	71	152	71	71	71	152
Total w/DR	816	889	1,003	903	769	1,003	987	889	923

As shown, installed coal capacity is significantly reduced by 2030 relative to 2010 in all futures under the input assumptions developed in Task 4. The futures with climate constraints (Futures 2, 3, and 8) reduce the amount of coal capacity in place more substantially. Nuclear capacity increases somewhat from 2010 levels in these same climate constraint futures and also in Future 7: Nuclear Resurgence. Combined cycle (CC) capacity increases substantially by 2030 from 2010 levels in all futures except Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid, and increases most markedly in the futures with climate constraints. Steam oil/gas capacity is reduced from 2010 levels in all futures, particular the futures with climate constraints. Hydroelectric capacity is not significantly impacted in any of the futures.

Onshore wind increases from 2010 levels in all futures, particularly those with climate constraints and/or RPS requirements (Futures 2, 3, 5, 6, and 8). Offshore wind capacity does not increase significantly from 2010 levels except in Future 6: National Renewable Portfolio Standard – Regional Implementation. Other renewable capacity; e.g., solar, landfill gas, biomass; increases somewhat from 2010 levels, most significantly in Future 6. The amount of additional HQ/Maritimes capacity installed to export to the Eastern Interconnection is either zero or relatively small in all of the futures.[21] The amount of demand response (DR) is an input assumption and is significantly higher by 2030 than in 2010 in all futures, particularly so in Futures 4 and 8.[22]

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[21] Assumptions regarding the potential expansion of the Maritimes and HQ systems to export additional hydroelectric/wind power to these neighboring regions were developed by the SSC. This expansion potential is modeled in NEEM as "pseudo-generators" that could be potentially constructed, depending on economics, inside of the neighboring NEEM region to reflect the expansion of these exports.

[22] The SSC developed an estimate of the demand response in terms of GW in each NEEM region for use in this study. The DR in each NEEM region is modeled in NEEM as a "pseudo-generator" that has a high variable cost

The total amount of installed capacity varies between all of the sensitivities as a function of the electricity demand for the future (see Table 4) and also as a result of the amount of variable resources (wind and solar) installed. Under the input assumptions developed in Task 4, these variable resources have reserve margin contributions of 30% or less of their installed capacity value. As such, and all else being equal, as variable resource installations increase, the more total capacity will be needed in aggregate to meet planning reserve requirements in each future/sensitivity.

2.5.3.3 *Generation by Capacity Type, Demand and CO_2 Emissions*

For these same key sensitivities for each future, Eastern Interconnection generation as a percent of Eastern Interconnection energy consumption in 2030 is shown in Table 4 for six key capacity types: CC, coal, nuclear, onshore wind, offshore wind, and hydroelectric facilities. Also shown are the Eastern Interconnection energy consumption and Eastern Interconnection CO_2 emissions in 2030 for these same cases.

Table 4: 2030 Eastern Interconnection Generation as Percent of Eastern Interconnection Demand for Six Key Capacity Types, 2030 Eastern Interconnection Demand, and 2030 Eastern Interconnection CO_2 Emissions

	BAU	F2 Hard	F3 Hard	F4B	F5 Hard	F6 Hard	F7B	F8 Hard
CC	25%	26%	37%	16%	15%	13%	19%	26%
Coal	38%	1%	2%	41%	32%	33%	39%	0%
Nuclear	22%	31%	32%	27%	23%	23%	27%	35%
On-Shore Wind	5%	30%	18%	5%	20%	13%	5%	27%
Off-Shore Wind	0%	0%	0%	0%	0%	4%	0%	0%
Hydro	5%	7%	7%	7%	6%	6%	6%	8%
Total	96%	96%	96%	96%	96%	91%	96%	96%
Demand (TWh)	3702	3248	3248	3008	3609	3609	3700	3008
Change from BAU		*-12%*	*-12%*	*-19%*	*-3%*	*-3%*	*0%*	*-19%*
CO2 (MilMetricTons)	1716	296	408	1367	1310	1316	1650	264
Change from BAU		*-83%*	*-76%*	*-20%*	*-24%*	*-23%*	*-4%*	*-85%*

As shown, the supply of energy from each of the six key capacity types varies considerably by future, but in aggregate, these six types supply more than 90% of the Eastern Interconnection energy in all futures. The futures that include carbon constraints (Futures 2, 3, and 8) drive the share of Eastern Interconnection generation from coal-fired facilities to nearly zero by 2030. Onshore wind generation as a share of total energy demand increases significantly in the carbon constrained and RPS futures (Futures 2, 3, 5, 6, and 8).

Relative to the BAU, electricity demand in the Eastern Interconnection in 2030 falls by more than 12% in the carbon constrained futures (Futures 2 and 3), and by nearly 20% in Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid and Future

applied ($750/MWh). Thus, this DR will generally not assist in meeting energy demand but will reduce the need for capacity expansion.

8: Combined Federal Climate and Energy Policy. Relative to the BAU, CO_2 emissions in 2030 in the Eastern Interconnection decrease by roughly 20% in the RPS futures (Future 5 and 6), and 80% in the carbon constrained futures (Futures 2, 3, and 8).

As part of the selection process used to identify the three scenarios for detailed transmission analysis, a detailed comparison of a number of key results for each of the 80 model runs was prepared by stakeholders using the output reports.

2.5.4 Future by Future: Key Findings

Captured below are some of the key economic findings in each future. In assessing these results, it is important to understand that each model run has perfect foresight about the future; i.e., future gas prices, new capacity costs, demands, etc. The model will retire/build units to minimize costs, even if the savings are small. With uncertainty, these decisions would not necessarily be made in the same way in the real world. Sensitivity analyses are useful to help assess the impact of uncertainty.

2.5.4.1 *Future 1: Business As Usual*

Future 1: Business As Usual incorporates policies already in place or expected to be in place in the near term, but does not include any additional policies such as climate change legislation. Model run findings are as follows:

- Base Case
  - In the BAU, the relatively low gas price forecast in comparison to the high prices incurred several years ago makes new gas-fired capacity economically attractive in comparison to older, existing coal units with high fixed O&M and relatively high variable costs.
  - In addition, many coal units face additional costs by 2020 for cooling water, coal ash, scrubbers, selective catalytic reduction (SCR) systems, and mercury controls to achieve compliance under new EPA regulations. Based on the BAU input assumptions, 95% of large Eastern Interconnection coal plants require at least one retrofit, and many require multiple retrofits.
  - BAU assumptions for forced generating unit builds (specific units not existing but are already planned to be placed in service), DR, and load growth are such that even with no economic generation builds or retirements, the Eastern Interconnection is long in capacity through 2030 (96 GW long in 2015 and 48 GW long in 2030). The model will seek to minimize total costs, and will retire units no longer needed to meet reserve requirements.
  - The combination of low load growth, high DR, and high forced builds combine to make both coal and oil/gas steam units economically retire in significant numbers.
    - As shown in Table 5, in addition to the forced retirements of 12 GW of coal and 2 GW of steam oil/gas under existing plans, 55 GW of coal and 35 GW of steam oil/gas units economically retire in the Eastern Interconnection by 2015.

Another 15 GW of coal-fired capacity retires by 2020 as the recent EPA regulations come into place.

- Most of the additions in 2015 represent forced in capacity. As shown, by 2030, CCs are the dominant economic expansion choice in the BAU with onshore wind expansion also contributing.

Table 5: BAU: New Builds and Retirements by Capacity Type for the Eastern Interconnection – 2015, 2020, and 2030 (GW)

	2010 In-Service	---- Additions ----			---- Retirements ----			2030 In-Service
		2015	2020	2030	2015	2020	2030	
Coal	271.9	8.5	0.0	0.0	66.8	14.8	0.0	198.8
Nuclear	99.8	2.7	4.5	0.0	0.0	0.6	1.5	105.0
CC	132.7	30.7	17.7	26.2	5.5	0.0	0.0	201.8
CT	120.3	4.7	4.4	4.4	2.2	0.0	0.0	131.7
Steam Oil/Gas	74.5	0.0	0.0	0.0	37.6	0.4	0.4	36.1
Hydro	44.6	0.0	0.0	0.0	0.0	0.0	0.0	44.6
On-Shore Wind	18.7	22.2	12.1	14.8	0.0	0.0	0.0	67.8
Off-Shore Wind	0.0	0.5	0.0	1.1	0.0	0.0	0.0	1.6
Other Renewable	3.6	2.3	3.3	4.5	0.0	0.0	0.0	13.7
New HQ/Maritimes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	17.1	0.0	0.0	0.0	0.0	0.0	0.0	17.1
Total	783.3	71.6	42.1	50.9	112.1	15.8	1.9	818.2
DR	33.1	-1.3	16.8	22.1				70.7

- Soft-Constraint Runs
  - Two soft constraint sensitivities were run in the BAU, one with shadow prices set to 25% of their level in the base case (OL25) and one with shadow prices set to 75% of their level in the base case (OL75).
  - Based on the results of the BAU base case and soft constraint runs, no interregional transmission expansion was applied in the remaining Future 1 sensitivities.
  - In large part, with low gas prices, new gas-fired plants, which can be constructed almost anywhere in the Eastern Interconnection, are usually the economic new generation choice thereby limiting the need for a significant interregional transmission expansion in the Eastern Interconnection
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
  - With high load, as in Future 1 Sensitivity 4 (F1S4), most of the additional capacity installed is comprised of gas-fired CCs and combustion turbines (CTs). With Low load (F1S5), coal plant and steam oil/gas retirements increase and fewer CCs, CTs, and wind are constructed.
  - With high gas prices (F1S6), coal retirements decrease and additional new coal and wind capacity is constructed. Fewer CCs and CTs are constructed, and more steam oil/gas retires. With extra high gas prices (F1S7), 2030 results are fairly similar to F1S6, as gas prices are the same by 2030.
  - With extra low renewable costs (F1S8), 52 GW of additional onshore wind is installed and 3 GW of offshore wind is installed in VACAR. Other renewable builds

are essentially unchanged. With low renewable costs (F1S11), results are similar in direction to F1S8.
  - With Increased EE/DR and RPS (F1S9), CC and CT installations are reduced because of lower overall demand. Eastern Interconnection wind and other renewable installations increase by 8 GW to meet the higher RPS. With reduced EE/DR and RPS (F1S13), results include increased CC and CT installations in response to higher demand and reduced wind builds in response to lower RPS.
  - With high PHEV (F1S10), CCs and CTs are installed to meet the additional demand.
  - With new EPA regulations delayed (F1S12), coal plant retirements decrease by 15 GW, offset by increased steam oil/gas retirements and reduced CC installations. With a five-year delay in new EPA regulations (F1S14), there is a modest reduction of 4 GW in Eastern Interconnection coal retirements.
  - With production tax credit (PTC) expiration and no RPS (F1S15), Eastern Interconnection onshore wind construction is reduced substantially by 30 GW. Only forced onshore wind installations of 23 GW take place. With PTC expiration and no RPS and high load (F1S16), results are similar to F1S15 for wind. CC and CT capacity is constructed to meet the additional demand.

2.5.4.2 *Future 2: National Carbon Constraint – National Implementation*

In Future 2, carbon prices are implemented to reduce U.S. CO_2 emissions by 42% by 2030 and 80% by 2050 from 2005 levels. Canadian NEEM regions face the same carbon prices. In addition, Eastern Interconnection NEEM regions are aggregated into four solar/wind intermittency regions, each with an intermittent generation limit equal to 35% of the load in that region. Model run findings are as follows:

- <u>Base Case</u>
  - Achieving the 80% emission reduction in 2050, absent earlier year banking, requires a significant increase in carbon prices. The CRA iteration process to match the 2030 and 2050 targets yielded a carbon price that was $27/ton (2010$) in 2015 rising to $140/ton in 2030, and then increasing to $369/ton by 2040 and further thereafter.
  - The CO_2 prices and the feedbacks between MRN and NEEM results in changes in gas prices and electricity demand between the BAU (F1S3) and Future 2 base case.
    - Higher electricity prices and lower GDP reduce electricity demand in the Eastern Interconnection by 12% by 2030.
    - Gas prices increase as CCs are built in the early years in the Future 2 base case. But as CO_2 prices increase further, CCs become uneconomic thereby reducing gas demand and yielding a significant decrease in gas prices.
  - In comparison to the BAU, additional coal plants are retired in the early years and replaced largely with CCs. Later, wind expansion becomes dominant along with nuclear. At these CO_2 prices, new integrated gasification combined cycle with carbon capture and storage (IGCC w/CCS) plants and CCS retrofits are minimal as these options are uneconomic in comparison to CCs in the early years and later to wind/nuclear. Twenty-six GW of offshore wind is constructed in 2035, but little prior

    - to that time. Biomass similarly begins to be constructed in significant amounts in 2035.
    - The mix of Eastern Interconnection generation as a percent of Eastern Interconnection load changes considerably from the BAU to Future 2. The CC share increases rapidly while coal is reduced significantly. Later, onshore wind and nuclear become dominant.
- Soft Constraint Runs
    - Two soft constraint sensitivities were run with shadow prices set to 75% of their level in the base case (OL75) and 25% of their level in the base case (OL25).
    - Compared to the Future 2 base case, more wind is added in F2S1 (75%) and F2S2 (25%) largely in place of CCs. Also more CTs are added/less steam oil-gas retired to meet reserves when importing more wind energy. F2S1 and F2S2 Eastern Interconnection builds are not dramatically different as wind is reaching intermittency limits. In 2030, Eastern Interconnection wind generation is 25% of Eastern Interconnection energy demand in the Future 2 base case, 30% in F2S1, and 32% in F2S2.
    - The OL75 case was chosen to create hard limits to apply in the remaining Future 2 sensitivities. This resulted in an additional 40 GW buildout of interregional transmission.
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
    - Hard limits (F2S11) yield overall expansion similar to F2S1 (75%).
    - In comparison to F2S11, low gas (F2S7) and low CO_2 prices (F2S9) yield more CCs and less wind by 2030. Fifty percent friction (F2S3) does not change the overall builds much.
    - With wind/solar regional intermittency limits increased from 35% to 50%, more wind is constructed.
    - With carbon prices after 2030 remaining constant in real terms, CCS retrofits are less economic leading to more coal retirements yielding less coal and more CCs.

2.5.4.3 *Future 3: National Carbon Constraint – Regional Implementation*

In Future 3, the carbon constraint is implemented regionally. The same carbon prices derived in Future 2 are applied in NEEM in Future 3. The key input assumption difference between Future 2 and Future 3 is:

- In Future 2, Eastern Interconnection NEEM regions aggregated into four solar/wind intermittency super regions, each with a 35% limit. All transfer limits can be expanded.
- In Future 3, Eastern Interconnection NEEM regions aggregated into seven solar/wind intermittency super regions, each with a 35% limit. Transfer limits cannot be expanded between super regions.

Key findings are as follows:

- Base Case
    - Compared to the Future 2 base case, less wind and more CCs are added in the Future 3 base case by 2030. With seven intermittency regions in Future 3, the 35% intermittency limit is more binding on the best wind locations; e.g., the Midwest ISO intermittency region is separate from PJM in Future 3.
    - In the Future 3 base case relative to the Future 2 base case, PJM_ROR, a separate super region, has more wind. MISO wind is reduced and located more to the West, to MISO_W and MAPP_US, and SPP wind is reduced.
    - With the same CO_2 prices, the U.S. electric sector CO_2 emissions in the Future 3 base case are somewhat higher than in Future 2 base case because there is less wind generation, but the difference is less than 5% or so of BAU CO_2 emissions.
- Soft Constraint Run
    - One soft constraint sensitivity was run with shadow prices set to 75% of their level in the base case (OL75).
    - The generation builds in the Future 3 base case and F3S1 (OL75) builds are not significantly different as transfer limits between the seven super regions cannot be increased to allow for greater importation of power.
    - F3S1 (OL75) was used to create hard limits to apply in the remaining Future 3 sensitivities. As mentioned above the pipes between super regions were not allowed to expand in this model, only pipes within the super regions were allowed to expand. This process resulted in a 5 GW buildout of transmission.
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
    - F3S12 (hard limits) builds are close to F3S1 (75%).
    - Low gas/low CO_2 increase CC builds and reduce wind builds. High nuclear cost swaps CCs for nuclear. High Canadian hydroelectric imports do not change the overall Eastern Interconnection results materially.
    - Additional other renewables are constructed in extra-low renewable costs in Future 3 (unlike Future 2).
    - With wind/solar regional intermittency limits increased from 35% to 50%, more wind is constructed.
    - With carbon prices after 2030 remaining constant in real terms, CCS retrofits are less economic leading to more coal retirements yielding less coal and more CCs.

2.5.4.4 *Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid*

In Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid implementation is assumed in comparison to the BAU, significantly reducing forecasted Eastern Interconnection electricity demand. Key findings are as follows:

- Base Case
  - The assumed reduction of 19% in total Eastern Interconnection demand by 2030 in comparison to the BAU yields less total capacity installed than in place in 2010. Most of the reduction from the BAU is in new CCs and CTs, along with more coal and steam oil/gas retirements.
  - Most of the new builds are the forced builds included in the SSI model.
- Soft Constraint Run
  - Given the projected decline in electricity demand, no soft constraint sensitivities were run in this future and the original transfer limits determined by the Planning Coordinators were used for the remaining sensitivities. As such, no additional transmission buildout was specified.
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
  - Compared to the BAU, total Eastern Interconnection demand in these cases are 17% to 33% lower by 2030. As in the base case, new builds are minimal and retirements are significant.

2.5.4.5 *Future 5: National Renewable Portfolio Standard – National Implementation*

Future 5 has a national RPS target starting at 7.5% in 2015 and reaching 30% in 2030 (MWh basis), with hydroelectric, wind, biomass, solar, geothermal and landfill gas energy counting toward the RPS. Key findings are as follows:

- Base Case
  - The inclusion of the national RPS and the feedbacks between MRN and NEEM result in changes to gas prices and electricity demand between the BAU and Future 5 base case. Eastern Interconnection electricity demand decreases by 2.5% by 2030 in comparison to the BAU. Beginning in 2020, gas prices decrease somewhat in the Future 5 base case relative to the BAU as more renewables are installed in place of CCs.
  - For the Future 5 base case, additional on-shore wind is constructed to meet the national RPS. Relative to the BAU, the additional wind replaces new CCs and coal.
  - Onshore wind continues to dominate the renewable options, as its economics tend to be more favorable than other renewable types in a national RPS.
  - The Future 5 base case has more generation from wind than the BAU, but less than the Future 2 base case. Onshore wind and hydroelectric are the key capacity types meeting the national RPS requirements. Future 5 base case has lower U.S. electric sector CO_2 emissions than the BAU, but not as low as the national carbon futures.
- Soft Constraint Runs
  - Two soft constraint sensitivities were run with shadow prices set to 75% of their level in the base case (OL75) and 25% of their level in the base case (OL25).

- In F5S1 (OL75) and F5S2 (OL25), the overall builds do not change significantly from the Future 5 base case, except less total wind capacity can be built to meet the same RPS as "better" wind locations can be reached.
- In F5S1 and F5S2, wind moves toward the "better" locations in SPP to meet the same RPS targets. In F5S2, NE (SPP-Nebraska) sees a large increase and MISO_W a large decrease. PJM_ROR sees an increase back to BAU levels, as the MISO and PJM_ROR wind decreases.
- The hardened version of the F5S1 (OL25) result was used for the remaining sensitivities. This resulted in a 64 GW additional buildout of transmission.

- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
  - F5S10 (hard limits) builds are close to F5S2 (OL25). Hard limits are used in F5S3 through F5S10. F5S10 hard limits moves some wind from SPP_N to MISO_W relative to F5S2 (25%).
  - The use of 50% hurdles (F5S8) does not change the overall Eastern Interconnection builds by type significantly, but does move some wind to Nebraska relative to F5S10 hard limit.
  - Clean energy standard (F5S5) of 70% by 2030 increases coal retirements, reduces wind builds and increases CC and nuclear builds relative to F5S10.

2.5.4.6 *Future 6: National Renewable Portfolio Standard – Regional Implementation*

Future 6 is a regional implementation of the national RPS. In Future 6, each individual super region has an RPS target starting at 7.5% in 2015 and reaching 30% in 2030 (MWh basis), with hydroelectric, wind, biomass, solar, geothermal and landfill gas energy counting toward the RPS. In Future 5, Eastern Interconnection NEEM regions are aggregated into four solar/wind intermittency super regions, each with a 35% limit, and all transfer limits can be expanded. In contrast, in Future 5, the Eastern Interconnection NEEM regions are aggregated into seven solar/wind intermittency super regions, each with a 35% limit and transfer limits cannot be expanded between super regions. Key findings are as follows:

- Base Case
  - In comparison to Future 5 base case, on-shore wind is replaced with offshore wind and other renewables in the Future 6 base case.
  - In Future 6 base case, onshore wind decreases in MISO and SPP and increases in PJM_ROR in comparison to the Future 5 base case.
- Soft Constraint Run
  - One soft constraint sensitivity was run with shadow prices set to 25% of their level in the Future 6 base case (OL25).
  - In F6S1 (25%), the overall builds do not change significantly from the Future 6 base case as transfer limit expansion between super regions is not permitted in Future 6.
  - In F6S1 (OL25) relative to the Future 6 base case, wind builds move from SPP_N to SPP_S and NE.

    - The hardened version of F6S1 (OL 25) was used for the remaining sensitivities. Again, only pipes within the super regions were allowed to expand. This process resulted in an additional 3 GW buildout of transmission.
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
    - F6S10 (hard limits) builds are close to F6S1 (OL25).
    - Relative to Future 5, more offshore wind and more other renewables are installed.
    - Clean energy standard (F6S4) of 70% by 2030 increases coal retirements, reduces wind builds and increases CC and nuclear builds relative to F6S10 (hard limits).
    - Wind builds by region are relatively consistent across the cases in this regional RPS future.

2.5.4.7 *Future 7: Nuclear Resurgence*

In this Future, 12 new nuclear plants with of 23,124 MW of capacity by 2020 are forced in the model. This compares to three new nuclear plants with 5,734 MW of capacity in the BAU. In additional nuclear build limits are increased from the BAU and new nuclear unit base overnight capital costs are decreased by 20%. Key findings are as follows.

- Base Case
    - In the Future 7 base case, relative to the BAU, the additional nuclear power largely replaces CCs.
    - Aside from the additional forced in nuclear units, the additional amount of nuclear units built in comparison to the BAU is relatively small given the relatively low gas prices and the lack of a carbon constraint.
- Soft Constraint Run
    - One soft constraint sensitivity was run with shadow prices set to 25% of their level in the base case (OL25).
    - As in the BAU, the F7S1 soft constraint run does not materially change the Future 7 base case builds.
    - As such, the SSC chose to use the base case limits for this future, resulting in no additional transmission buildout.
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
    - Nuclear builds increase substantially when carbon prices are applied in the electric sector (F7S3).
    - SMR assumptions do not result in additional economic nuclear builds by 2030 (F7S4). There is a small increase after 2030.

2.5.4.8 *Future 8: Combined Federal Climate and Energy Policy*

In Future 8, the national carbon implementation and carbon reduction targets in Future 2 are combined with the national RPS policy in Future 6 with an RPS target of 25% in 2030 instead of

30%. In addition, electricity demand in Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid is used resulting in a 19% decrease in electricity demand from the BAU by 2030. Key findings are as follows:

- Base Case
  - The carbon prices and gas prices in the Future 8 base case are nearly identical to those in the Future 2 base case, as the added RPS in Future 8 is not binding given the amount of wind built in response to carbon prices.
  - In the Future 8 base case, lower demand and higher DR reduce the CC and wind builds relative to the Future 2 base case.
- Soft Constraint Case
  - Both OL25 and OL75 soft constraint sensitivities were run.
  - In F8S1 and F8S2 relative to the Future 8 base case, more wind is constructed in MISO_W and SPP as transfer limits are relaxed.
  - F8S1 (OL75) was used as the basis for the hard limits for F8S3 and F8S4 resulting in a 37 GW buildout of transmission.
- Additional Sensitivities *(See http://eipconline.com/Modeling_Results.html for further details.)*
  - In comparison to F8S1 (OL75), both the low renewable cost (F8S3) and high RPS (F8S4) cases increase wind builds in place of CCs.
  - In comparison to F8S1 (OL75), the increased wind builds in F8S3 and F8S4 are largely in MISO.
  - In comparison to F8S1 (OL75), both F8S5 (OL75, flat carbon prices after 2030) and F8S6 (OL75, flat carbon prices after 2030) yielded higher CC builds, lower CT and coal capacity. Wind builds were slightly lower, and located more predominately in eastern MISO, and less in MISO_W.
  - In comparison to F8S1 (OL75), F8S7 (Hard Limits, flat carbon prices after 2030) has higher CC builds, but a similar amount of wind builds. In addition, F8S7 also has more wind builds in MISO_W, and the MISO CCs and MISO eastern wind are dispersed throughout the MISO region.

2.5.5 High-Level Transmission Cost Estimates

As noted in Section 2.5.4, stakeholders developed increases to the transfer path limits between NEEM regions for Futures 2, 3, 5, 6, and 8 to use in sensitivity analysis for each of those futures.

To support the SSC in assessing the results of the macroeconomic analysis and reaching consensus on the three future scenarios of interest, the EIPC developed an approach which employs generic, high-level transmission expansion cost estimates for use in comparisons among the macroeconomic scenarios. Because generic cost estimates are needed to develop and select scenarios of interest prior to specific modeling and detailed power flow analysis to be performed in Phase 2 of the project, they were intended only for use by the SSC in quantifying levels of transmission impacts among the many uncertain future expansion scenarios being considered relative to each other.

The approach applied in developing the high-level cost estimates was to utilize generic transmission line building blocks in a consistent manner by each of the Planning Coordinators to approximate the SSC requested increases in transfer capability between regions represented in the macroeconomic scenarios. EIPC also compiled a cost matrix of planning level, "cost per mile" estimates for common high voltage alternating current (HVAC) voltage levels among the Planning Coordinators. It was determined that the NEEM regions represented enough geographic diversity to warrant differences in regional costs. Therefore, 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.

These generic building blocks and cost estimates do not represent likely project solutions and were not intended to reflect specific facility costs. The absolute dollar values of these generic estimates were intended only to assist the SSC in selecting scenarios of interest, and are not applicable for other purposes or in any way indicative of actual transmission expansion costs, which must be developed through detailed local and regional assessments of specific expansion requirements. Examples of costs not considered include substation costs, upgrades to existing transmission systems, financing costs, specific right of way (ROW) routing requirements, etc. The procedure and cost matrix can be found in "Task 5 High Level Cost Matrix" found at: http://eipconline.com/uploads/Task_5_High_Level_Cost_Matrix_8-10-11.xlsx.

As part of the process the following approach/assumptions were utilized:

1) Existing system capacity between NEEM regions was fully utilized and could not be relied upon; therefore, only new transmission enhancements were utilized to obtain the requested increase in transfer capability.
2) To represent the increases in transmission capacity between NEEM regions, EIPC utilized green field, generic transmission line building blocks.
3) To represent contingency capability, the approach included redundant circuits; e.g., for a 1,000 MW increase, a minimum of two 1,000 MW circuits were used with the second circuit accounting as a reinforcement to support the contingency loss of the first.
4) Planning Coordinators determined the termination points for the transmission line building blocks based upon knowledge of their local system(s).
5) No power flow analyses were performed.
6) Local impacts to the sending and receiving ends of the proposed circuits were not specifically addressed.
7) The integration of remote resources and large blocks of resource additions were considered as needed on a case-by-case basis.
8) In some limited locations, high voltage direct current (HVDC) solutions were considered in the high-level analyses.

In the development of the high-level transmission analysis solutions, coordination between the Planning Coordinators resulted in the identification of building blocks that approximated the SSC requested increase in transfer capability. In some cases where a substantially large increase in transfer capability was requested, the Planning Coordinators included additional transmission infrastructure to account for internal considerations of their respective regions.

The results of applying this procedure to each of the futures selected by the SSC in Task 5 are shown at "Results for Task 5 Production Cost Modeling" found on the EIPC Web site at EIPC Modeling Results, found at: http://eipconline.com/Modeling_Results.html. Table 6 below provides a summary of the estimated maximum and minimum cost developed for each future. This exercise did not evaluate the cost effectiveness of the transmission expansions. It makes no comparison of the estimated expansion costs to the potential system savings to determine anticipated net benefits. Further consideration including a more detailed analysis of system and subsystem costs and impacts in the respective regions would be necessary to determine which expansions may or may not be cost effective.

Table 6: High-Level Transmission Cost Estimates for each Future (Total Eastern Interconnection)

Future	Low	High
Future 2 OL 75 Total Cost:	$34,122,876,200	$48,799,582,300
Future 3 OL 75 Total Cost:	$1,730,666,200	$2,674,747,300
Future 5 OL 75 Total Cost:	$39,191,496,200	$58,332,337,300
Future 6 OL 25 Total Cost:	$2,069,929,200	$3,114,593,550
Future 8 OL 75 Total Cost:	$36,684,818,200	$51,054,582,550

2.5.6 Additional Cost Estimates Requested by SSC

The SSC directed the 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. These costs are associated with an increase of EE/DR/DG in Futures 4 and 8, nuclear uprate costs in Future 7, and an increase of intermittency penetration limit beyond 25% for variable energy resources in all futures except the BAU. Additionally, the SSC also agreed that the MWG may develop integration costs for other generation types, as appropriate. The estimates developed by the MWG incorporated the best information that could be assembled within the time frame allowed. These estimates should be used in the context of the stakeholder selection process for selecting the three scenarios to be further analyzed from a transmission perspective in Phase 2. As such, these results only provide an order of magnitude of possible costs and are suited only for comparing futures rather, than predicating absolute costs.

The decision was made to base the cost estimates on generally acceptable, current, publically available information. The MWG worked with stakeholders and representatives from DOE and national laboratories to identify and review available information on the required costs. Ranges of cost estimates were provided to reflect the uncertainty and variability of the cost estimates. Below is a summary of the process and results of this effort.

2.5.6.1 *Energy Efficiency Costs*

The objective of estimating the energy efficiency costs was to provide the incremental costs of energy efficiency in Futures 4 and 8 compared to the Business as Usual future. The cost estimates developed reflect only costs associated with electricity savings. Two studies were deemed by the group to meet the criteria established. The studies were 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-$40/MWh. 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% of electricity reduction while the Georgia Tech study showed prices increasing to approximately $160/MWh at 33% reduction in electricity. The studies did not estimate costs beyond those levels and the SSC decided to keep the costs flat at those levels for electricity reductions up to 50%. To accommodate uncertainty in the estimates, the stakeholders decided to create a range of estimates at the 50% penetration level by adding 20% to the cost estimates. This ultimate impact on the costs estimates was zero or minimal because so little of the electricity saved was beyond the peak points from the two studies.

Table 7 presents the net present values (PV 2010) for 2015-2030 for the futures studied:

Table 7: Non-NEEM Estimated Energy Efficiency Costs (2010 Present Values for 2015-2030 in $Billions)

Future	McKinsey	Georgia Tech	Average
BAU	$5.4	$13.6	$9.5
F4	$43.4	$125.9	$84.6
F4S3	$170.2	$289.7	$229.9
F4S3 (+20% marginal costs @50% electricity reduction)	$171.8	$290.4	$231.1

2.5.6.2 *Demand Response (DR) Costs*

In order to estimate the cost of the DR programs defined for the BAU, Future 4, and Future 4S3, an estimate of DR marginal costs per megawatt avoided was developed and applied to the megawatts of marginal peak load reductions achieved through DR programs as forecast in the F4, F4S3, and BAU NEEM futures. Future 8 scenarios also used the same costs as the Future 4 analyses. Below is a summary of the process and results.

The estimate uses estimated costs per customer ($/customer) for DR programs from recent studies. These are divided by calculations of the potential peak load reduction per customer

(MW/customer) from FERC's National Assessment of Demand Response (NADR) model and FERC's 2011 survey of DR and advanced metering. The computed result is costs per megawatt potential peak load reduction ($/MW); i.e., costs per megawatt-avoided. This calculation creates a range of estimates based on both the range of potential MW reductions/customer and the range of cost estimates to achieve a MW of reduction.

These cost per megawatt values are multiplied by the incremental peak load reductions per year through DR that serve as inputs to the NEEM model's F4, F4S3, and BAU futures to produce costs of DR programs per NEEM region per year; NPV of these costs are computed and displayed as the final results. Cost estimates were derived from the following sources:

1. Electric Power Research Institute: Estimating the Costs and Benefits of the Smart Grid (2011).
2. KEMA, Inc.: California solar initiative: For metering, monitoring and reporting market photovoltaic systems in California (2009).
3. Department of Energy: Recovery act selections for smart grid investment grant awards by category (2010).
4. Energy Information Administration: Form 861, File 3 (2009).
5. Federal Energy Regulatory Commission: National Assessment of Demand Response (2009).
6. Federal Energy Regulatory Commission: Survey of Demand Response and Advanced Metering (2011).

Each of the sources had a high and a low estimate of the costs of DR. Ultimately, the KEMA, Inc., low estimate was recommended because it encompassed the widest range of the estimates. Below are the KEMA results for each of the three futures.

Table 8: Non-NEEM Estimated Demand Response Costs (Results in $Billions)

Future	NADR	FERC	Average
Business As Usual	$1.2	$0.5	$0.8
Future 4 – Aggressive EE/DR	$7.8	$1.6	$4.7
Future 4 S3 - +1% Increase	$9.9	$2.0	$6.0

2.5.6.3 *Distributed Generation (DG) Costs*

The DG included in the BAU was based on the AEO 2011 forecast, some behind the meter and some utility scale. For the aggressive renewable DG called for in Futures 4 and 8, twice the BAU DG was included, all of which are behind the meter with photovoltaic (PV) systems. The estimated cost of the renewable distributed generation for 2015-2030 is $98 billion. This estimated cost was based on a fixed charge rate of 11.38% assuming 20 years of operation and a discount rate of 5%.

The PV capital costs included in the AEO 2011 were for utility-scale projects rather than the small-scale systems. Consequently, the MWG had to deviate from the protocol of using AEO for capital costs. Instead, a 2010 Lawrence Berkeley National Laboratory study, "Tracking the Sun III," was used and the capital costs were assumed to be the weighted average of the 2-5 kW and 5-10 kW systems ($8045/kW$_p$) to reflect the most likely sized systems to be installed to meet this aggressive goal. The learning rate assumptions, 20% aggregate reduction from 2011 to 2025 with constant cost after 2050, are consistent with SSC assumptions applied to utility-scale solar and other technologies.

2.5.6.4 *Nuclear Uprate Costs*

Both the BAU and Future 7 included nuclear uprate as part of their assumptions. The BAU assumed 1,538 MW and Future 7 assumed 8,687 MW. The costs of these uprates are not captured in the NEEM output. Consequently, the SSC directed the MWG to estimate the cost of the nuclear uprates based on $2,600/kW. The estimated costs for the nuclear uprates are $4.8 billion for the BAU and $27.4 billion for Future 7. 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%.

2.5.6.5 *Thermal Integration Costs (Contingency Reserves)*

The cost information provided with the MRN-NEEM results does not incorporate the costs associated with maintaining contingency reserves needed for power system reliability in the event of the sudden loss of a large generator. Contingency reserves are generally made up of fast-acting resources that are held at all times in case a large generator experiences a forced outage and goes offline. Because these costs are not being captured in the MRN-NEEM, and because the MWG recommends inclusion of integration costs for variable generation, including the integration costs of large nuclear, coal, and natural gas CC units may allow greater comparability of costs among different cases.

Some stakeholders believe that the need to account for additional contingency reserves is extremely unlikely since that would only occur if a future resource were to exceed a region's existing largest contingency. While these costs were developed to inform Phase 1 of this study, the MWG recommends that during Phase 2 the Planning Coordinators add new transmission and generation units consistent with traditional planning methods that expand the system in a manner with lowest costs. This often results in adding new transmission and generation in such a manner that the largest single contingency remains unchanged, and therefore would avoid any incremental costs.

The cost estimates for thermal integration were based on a 2003 study, "Allocating Costs of Ancillary Services: Contingency Reserves and Regulation," by Eric Hirst and Brendan Kirby for Oak Ridge National Laboratory. The study estimated the average cost of contingency reserves across all generators at $2/MWh. Results range from $45-$75 billion depending on the future and sensitivity.

2.5.6.6 *Variable Energy Resource (VER) Integration Costs*

The SSC directed the MWG to quantify 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 the BAU and to all VERs above the BAU penetration limits in all other futures. 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.

There are a wide variety of studies that attempt to quantify the incremental operational costs of integrating large quantities of VERs. 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 analyzes the operational impacts of high wind penetration scenarios that the SSC directed the MWG to reflect in this cost analysis.

EWITS analyzed 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. Some of the model runs also reach fairly high penetration levels; e.g., 40.6% in PJM-MISO for F2S12. There were four EWITS configurations defined for study 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 futures. The EWITS Configuration 1 integration cost is $5.13/MWh (2009$).

The MWG had significant discussions of the appropriate range of values that should be used to capture the uncertainty around the cost estimates. On one hand, the EWITS estimates do not address the higher penetration rates of wind that were included in some of the futures. On the other hand, EWITS does not take into account the full range of resources that could be available by 2030 to facilitate VER integration. This could reduce the integration costs of wind and therefore the costs reported in EWITS could be overestimating the cost of reaching high VER penetrations. Given the uncertainty of the future integration cost at higher penetrations, the MWG decided to bound the EWITS Configuration 1 costs by a minus 50% and plus 75% range. The EWITS VER integration costs were also adjusted to account for different levels of natural gas prices between the EWITS and EIPC studies.

The NPV of the Eastern Interconnection total integration cost for the F1S3 BAU case was $15 billion with a lower range (50%) of $7.5 billion and an upper range (175%) of $26.3 billion. The hardened Future 2 scenario had a cost of $34 billion ($17 to $60 billion).

2.5.6.7 *Summary and Implications*

Overall, the development of these costs added $75 and $470 billion to the total energy cost estimate of $1.6 to $2.4 trillion of costs (2010 present value of the costs over the 2015-2030 period). On a percentage basis, the additional costs added between 4% and 27% to the total costs depending on the future and range of costs. The objective was for stakeholders to use these costs to inform their choices for the three scenarios for detailed transmission buildouts. The costs were available for the stakeholders to review in the cluster analysis (see Task 6 description in Section 2.6).

2.6 Task 6 – Expansion Scenario Concurrence

The selection of the scenarios by the SSC followed a similar process to that employed for the development of the macroeconomic futures (Task 4). At the May 2011 SSC meeting, the SSC established the Scenario Task Force (STF), a small work group to develop recommendations on the three scenarios to be submitted for detailed transmission analysis. It was intended that the Planning Coordinators will use the information from the scenario analyses to inform the regional planning processes and the structure of the system; therefore, the STF's work was carefully undertaken and monitored closely by many parties.

Representation on the STF was restricted to three people from EISPC and one person from each of the remaining seven sectors to have a manageable group collaborating and reaching consensus on the scenarios. These individuals represented their sectors in any decision-making undertaken by the STF, then STF recommendations were provided to the SSC for adoption. Keystone facilitated the STF's meetings, which were open to all interested stakeholders, and EIPC provided a liaison to the STF for coordination purposes.

At the May 2011 SSC meeting, important questions were raised regarding the purpose of studying these three scenarios in Phase 2:

- How much do certain policy choices diverge in terms of the transmission buildout they would require?
- What is to be gained by planning transmission on Eastern Interconnection-wide basis versus the current regional planning process or planning at the super region level?

SSC members also discussed the importance of studying scenarios that encompassed a range of policy drivers and resulted in robust transmission buildouts.

Based on this SSC discussion, the STF worked to develop recommendations on the objectives, criteria and process that should guide the selection of the three Phase 2 scenarios. This was considered a useful step to focus the work of the group and to ensure that the scenarios ultimately selected for study in Phase 2 would be selected based on sound criteria, through a well-designed process, reflective of the group's agreed-upon articulation of the project's purpose and objectives.

The STF, and ultimately the SSC, agreed that the main purpose for Phase 2 was to see a range of transmission buildouts that reflect distinct policy scenarios of interest to stakeholders. As articulated by the STF in a memorandum to the SSC summarizing their recommendations on the objectives, process, and criteria for scenario selection:

> "The main, guiding objective for the selection of scenarios to be studied in Phase 2, is to end up with a set of scenarios that are defined by different policy drivers, and to determine what different transmission buildouts may be needed to support these policy drivers."

The process developed for selecting the Phase 2 scenarios necessarily reflected the complexity of the decisions to be made. Two concepts discussed during the May 2011 SSC meeting were particularly influential in the design of the scenario development and selection process. The first is that of bookends. Numerous individuals and sectors expressed a desire for scenarios that represent significantly different bookends, both in terms of the policy futures they embody, and the transmission buildouts they would likely require. The second key concept is that of clustering the Phase 1 Task 5 macroeconomic analysis results based upon similarities in their transmission requirements and other key variables, in an effort to ensure that the final scenarios selected for Phase 2 analysis would result in robust transmission buildouts, and would share some key features with other cases of interest.

Examples illustrating the use of cluster analysis with respect to carbon versus transmission and energy flow versus generation by percent of total renewable are shown in Figures 10 and 11, respectively.

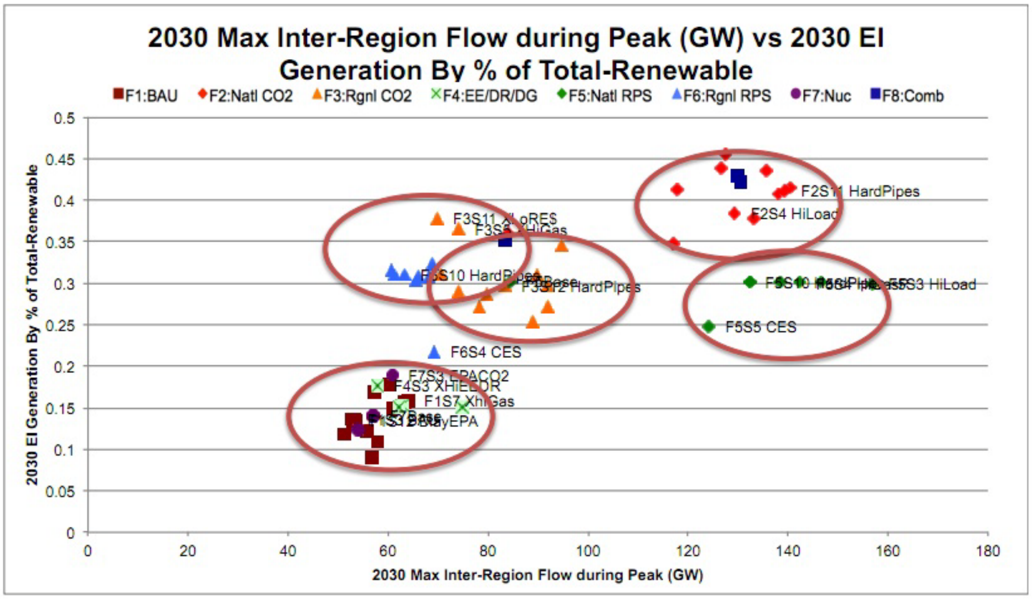

Figure 10: Energy Flow vs Generation by Percent of Total-Renewable

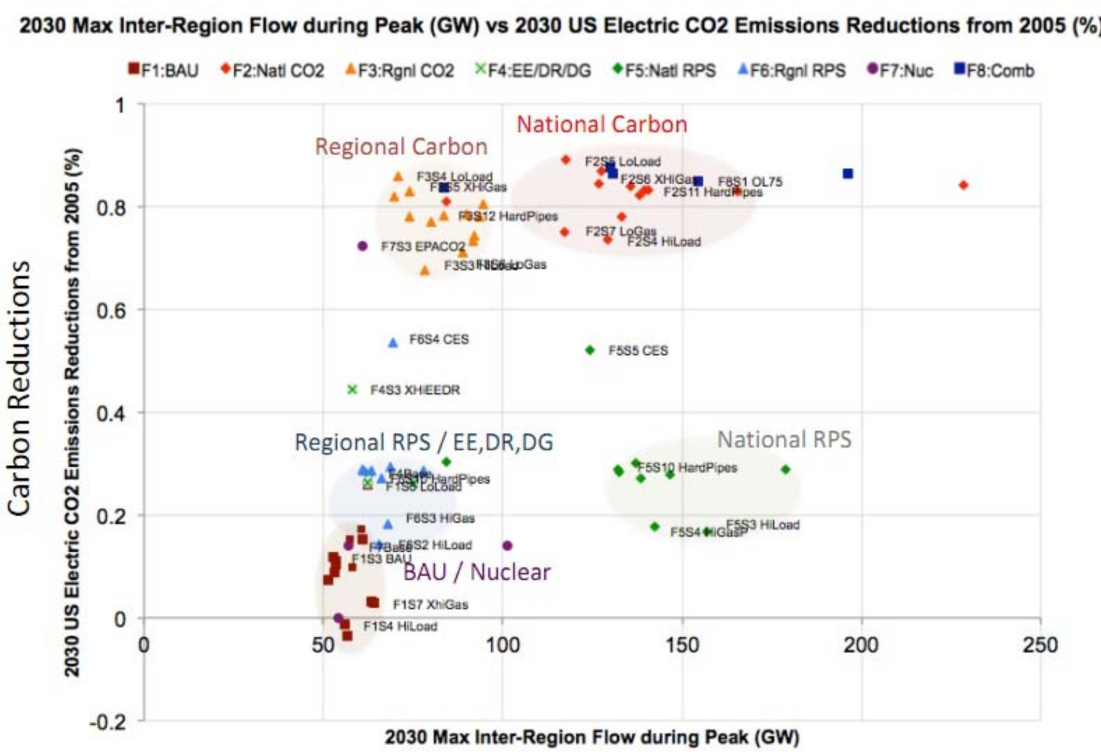

Figure 11: Carbon vs Transmission

The STF recommended a process that encompassed both the bookends and clustering concepts. This process involved first developing a general, loose definition of the bookends, and using that as a framework for selecting the scenarios. Next, the STF conducted a clustering analysis of all the Phase 1 future and sensitivity cases, which would enable stakeholders to see similarities and differences, then identify clusters of transmission expansion requirements, policy implementation options, and other variables of interest to stakeholders. The STF and the SSC ultimately determined how to use the results of these analyses to select three scenarios that would align with the bookend framework, address the interest in robustness, and meet any other criteria identified by the SSC.

The STF and SSC ultimately did not reach consensus on additional, specific criteria to apply in the selection of scenarios, beyond the primary objective of achieving diversity in terms of the policy drivers and likely transmission buildouts. However, in STF and SSC deliberations and in the STF's memorandum summarizing their recommendations, several additional considerations were discussed. These included generation and transmission costs, achieving the right balance between plausibility and "pushing the envelope," achieving a similar balance between comparability and greater variety of information, and resilience/robustness of the transmission buildout.

The STF presented their proposed objectives, process and criteria for the selection of scenarios at the July 2011 SSC meeting. Also during this meeting, the SSC discussed the bookends concept further and agreed that the bookending approach should yield the following types of scenarios:

- One BAU scenario or a high EE/DR/DG/Smart Grid scenario (Other).
- One regionally-implemented clean/green/low-carbon policy scenario (Regional).
- One nationally-implemented clean/green/low-carbon policy scenario (National).

Some sectors expressed a preference for bookends defined in terms of the type of transmission buildout they would likely yield, and acknowledged that these transmission-based scenarios would likely align with the policy-based scenarios discussed above.

Between July and September 2011, the STF held three conference calls and/or webinars to work through the scenario selection process as described above. The group's work during this period mainly focused on the clustering analysis. This involved analyzing all of the Phase 1 future/sensitivity runs, determining how they behaved across a range of variables, and determining what the relevant clusters were. This helped the group ensure that the Phase 1 model runs selected to define the three scenarios both achieved the desired level of variation across key variables and, as appropriate, were similar enough to other Phase 1 cases to indicate a measure of robustness. The STF was able to accomplish the required clustering analysis through assistance from Oak Ridge National Laboratory to construct a database for all the Task 5 model outputs from CRA so that they could be manipulated into graphs to compare across futures/sensitivities. A comparisons spreadsheet, presented at the July 2011 SSC meeting, was modified and updated regularly as each round of macroeconomic modeling results from Task 5 was released. STF members were able to adjust and calculate new variables at the STF's request, such as NPV total cost, cumulative emissions, and percentage CO_2 emissions, among other factors of interest to stakeholders.

The STF also worked to incorporate cost data into their discussions and analysis as it became available, including EIPC's high-level transmission cost estimate analyses and the MWG's estimates of increased EE/DR/DG/smart grid in Futures 4 and 8, and nuclear uprate costs in Future 7. Additionally, the MWG's memorandum to the STF covered integration costs for other generation types, as necessary. These ultimately included thermal integration costs and VER integration costs. The STF was able to take these costs into account based on technical assistance provided by Oak Ridge National Laboratory and was then able to fold the data into the total cost variable for the STF's analysis.

Cost data decisions were one of the more complex issues that the STF dealt with, especially since a significant portion of such data only became available for all the futures toward the very end of the STF's deliberations. Although the STF had reserved an important place for costs in ultimate consideration of the scenarios, it did not use it as an explicit clustering variable due to the timing associated with the availability of such data for all futures. While the potential cost for transmission was included in the STF's discussions, cost did not directly determine the STF's final recommendations to the SSC.

Throughout the discussion of the clustering analysis, many ideas were brought forward on how to organize the clusters, but due to the volume of information to interpret, the STF focused on the variables listed below as key indicators for clustering:

- Load growth patterns (high, low, etc.)
- Gas prices
- Emission reductions
- Generation type (high natural gas, high wind, etc.)
- Generation location
- Generation costs (high, low, etc.)
- Possible transmission buildout type
- Transfer limits/transfer limit increases
- Total energy transfers
- High-level transmission cost estimates (high, low, etc.)

As a next step, STF members narrowed down which metrics to use as measures of these variables and arrived at the following:

- Generation type as a percent of total generation was used to indicate generation mix.
- 2030 maximum inter-region flow during peak conditions (interface expansion signals from the soft constraint runs) was used to indicate likely transmission buildout as the transmission owners' and operators' proposal suggested.
- 2030 U.S. electric sector CO_2 percentage emissions reductions from 2005 levels were used to indicate emissions reductions.
- NPV levelized total cost/MW, as calculated by Oak Ridge National Laboratory, was used to indicate total cost of the generation and transmission buildouts.

Though the STF as a whole did not develop joint conclusions about the clustering analysis, task force members utilized the information individually and within their sectors to develop proposals and/or formulate positions on those proposals.

To expedite decision-making and limit the scope of its discussions, the STF first narrowed 76 future and sensitivity runs down to approximately one run per future or per bookend in the case of the national futures. Some sectors then used the results of this discussion to develop proposals for discussion at an in-person STF meeting on September 12, 2011. At this meeting, the STF reached consensus on three scenarios to recommend to the SSC. The SSC then approved these three recommended scenarios at its meeting on September 26-27, 2011. The scenarios for transmission buildout in Phase 2 are as follows:

1. Scenario 1 - Nationally Implemented Federal Carbon Constraint with Increased EE/DR
2. Scenario 2 - Regionally-Implemented National RPS
3. Scenario 3 - Business as Usual

The three scenarios approved by the SSC represent bookends which are balanced in terms of policy goals, levels of implementation, likely transmission buildouts, and likely total costs while achieving significant diversity across these variables.

In fulfillment of their SOPO Task 7, EISPC representatives to the STF and SSC workgroups actively participated in all aspects of the scenario selection process and in the formulation of the information provided in this section.

3.0 Description of Three Scenarios for Study in Phase 2

Phase 2 of this project will focus on representatives of EISPC and the SSC collaborating with EIPC who will conduct transmission studies on the final three scenarios. This work will include a number of studies regarding grid reliability and stability as well as studying the various options for transmission expansion. This Phase 2 work will be conducted during 2012 and is anticipated to be completed by the end of 2012. During 2012, EISPC's studies and whitepapers work will continue with anticipated completion by mid-2013.

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

The first scenario selected for Phase 2 study is a national carbon constraint and demand reduction scenario, driven by a nationally-implemented CO_2 price, as well as significant penetration of EE and DR. Costs of EE and DR are assumed to be partially offset by the CO_2 revenues.

To define this scenario in terms of the Phase 1 futures and sensitivities, the STF proposed a new seventh sensitivity to Future 8: Combined Federal Climate and Energy Policy. This sensitivity, F8S7, includes a CO_2 price that escalates annually to achieve a 42% reduction in CO_2 emissions throughout the economy by 2030 as in Future 2: National Carbon Constraint – National Implementation, but then becomes flat after 2030.[23] The SSC agreed that the scenario should include a flat carbon price after 2030 because the generation expansion results seemed more realistic.[24]

Like all Future 8 runs, F8S7 also includes the more aggressive EE/DR assumptions from Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid; 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 in Eastern Interconnection-wide demand by 2030 and greater than 30% of energy delivered with renewable resources. The inclusion of these features of Future 4 was deemed reasonable because complementary policies are likely in any carbon reduction program and the actual load reduction is less than the low load sensitivity in Future 2, F2S5.

[23] The base case of Future 8 and the transfer limits from the soft constraint sensitivity (F8S1) used the original CO_2 price forecast that continues to escalate between 2030 and 2050.
[24] As noted earlier, achieving an 80% economy-wide emission reduction in 2050, absent earlier year banking, required a significant increase in carbon prices after 2030, with prices increasing to $140 per ton by 2030, and then increasing to $369 per ton by 2040 and further thereafter.

This first scenario results in the most expansive transmission buildout of the three scenarios, and is robust enough to accommodate the transmission needs under Future 5: National Renewable Portfolio Standard – National Implementation, Future 2, and Future 4.

The F8S7 sensitivity incorporates the hardened interregional transmission buildout from F8S1, which results in a transfer capacity of approximately 37,000 MW. It also simultaneously addresses the generation concentration anomalies for wind and CC units as agreed to by the SSC in F8S6.

The generation anomalies were addressed in the following manner:

- 90% of the in F8S1 wind generation in MISO_W, MAPP_US, SPP_N, SPP_S, NE, and NYISO_A-F, are forced into the model at F8S1 levels.
- 90% of the wind generation in F8S1 eastern MISO NEEM regions is redistributed. 70% is reallocated based on available wind resources and 20% is based on the MISO RGOS findings.
- The high concentration of CC generation in MISO_WUMS and MISO_IN is redistributed based on the pattern of coal plant retirements in the MISO region. Specifically, 90% of the F8S1 CC generation in MISO_IN and MISO_WUMS are reallocated throughout MISO in proportion to total coal retirements.

Two intermediate sensitivities (F8S5 and F8S6) were run to adjust the anomalous wind and CC distributions and determine the resulting mix of generation and transfer capacity. However, these used the transfer capacity overload costs from the F8 base case with high CO_2 prices in the out-years in conjunction with the soft constraint approach. As a result, these sensitivities built less transfer capacity and instead shifted additional wind capacity to the eastern MISO regions, inconsistent with existing Planning Coordinator plans. The SSC decided that the larger buildout from F8S1 was more appropriate, so F8S7 uses the 37,000 MW buildout with the redistribution of wind and CC as described above.

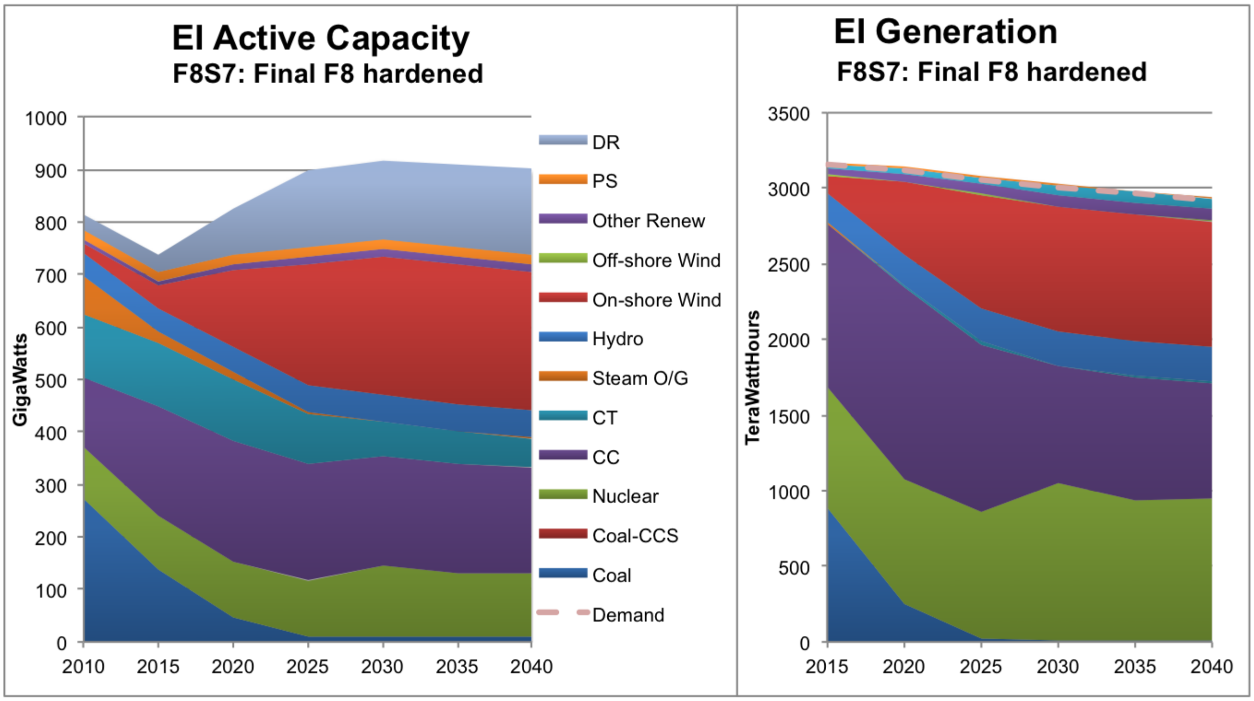

Figure 12: Scenario 1: Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response (F8S7)

3.2 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 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.

The greater diversity in supply mix; with coal, gas, wind, nuclear, hydropower, offshore wind and other renewable technologies generation; was an important reason why the SSC selected Future 6. The higher level of offshore wind seen in F6S10 was particularly important to some SSC members. In contrast, Future 3: National Carbon Constraint – Regional Implementation results in very significant coal retirements.

Additionally, stakeholders supported the selection of Future 6 because, in combination with the other scenarios, it provides information about a wider 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.

The SSC agreed that the regional scenario should be defined by F6S10), the hardened transfer limit (OL25) sensitivity. F6S10 and all Future 6 sensitivities are 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. To implement this regional approach, transfer limits between super regions were not permitted to expand.

The proposed regional scenario, F6S10, has a total transmission capacity expansion of 3,100 MW, which is similar to Future 3 and implies a measure of robustness in terms of the transmission buildout. However, the different generation mix and location for these two futures produce different transfer limits between the NEEM regions.

The SSC noted that F6S10 resulted in an unrealistically high concentration of gas-fired CTs in MISO_WUMS, but found that these CTs do not generate electricity in 2030, and therefore are likely located by the model in MISO_WUMS to meet MISO-wide reserve requirements. Since redistribution of the CTs would not likely change the transfer capacity results, the SSC did not see the need for a new NEEM run. In Phase 2, the newly formed Transmission Options Task Force (TOTF) will redistribute the CTs before undertaking detailed transmission analysis.

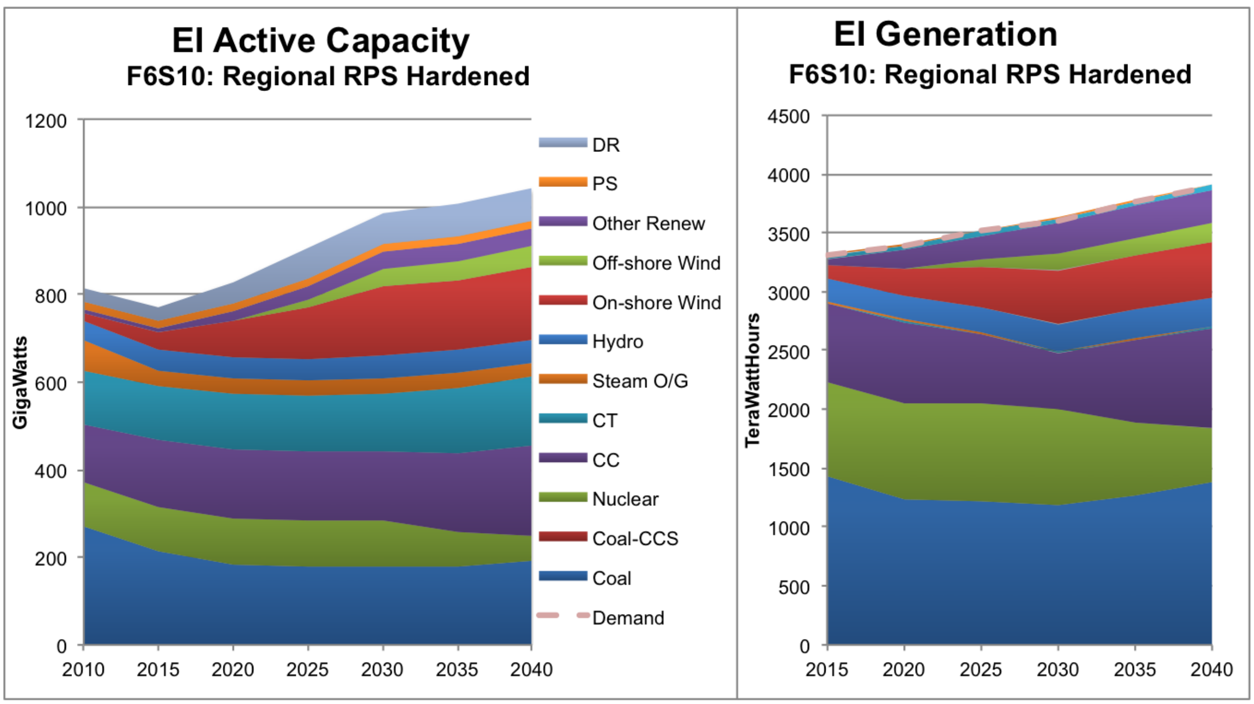

Figure 13: Scenario 2: Regionally-Implemented National Renewable Portfolio Standard (F6S10)

3.3 Scenario 3: Business as Usual

The SSC agreed that the third scenario is Business As Usual (BAU) from Future 1. BAU is characterized by no new federal, state, or regional energy or environmental policies or programs. Currently proposed EPA regulations 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 will be renewed on a case-by case basis. Fuel prices remain stable and there are no major technological advances.

The SSC specified that the transmission expansion would be defined by projects currently under construction or otherwise reasonably expected to be built. These transmission projects were selected by the SSC and designated as the SSI model. While the SSC decided not to expand NEEM transfer limits beyond these projects, the BAU has a significant number of generation retirements and new builds that will likely necessitate some transmission development within the NEEM regions to ensure continued system reliability. As such, the BAU will provide valuable transmission information.

The SSC considered both the Future 1 and Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid for this final scenario. Once it was clear that the policy goals of Future 4 could be accommodated within Scenario 1, SSC members coalesced around using Future 1 as a reference case for scenario analysis.

The NEEM run to be used for the Phase 2 inputs for this scenario is F1S17. To arrive at F1S17, the SSC agreed to make two adjustments to F1S3, the most accurate representation of currently approved EPA regulations. First, the post-adjustment sensitivity, designated F1S17, includes an increase in the SPP variable energy resource contribution to reserves from 6% to 15% to make it consistent with SPP's recommendation and the NEEM runs in Futures 2 through 8. Second, the combustion turbines in the NEEM region MISO_WUMS are reallocated throughout MISO based on each MISO NEEM region's share of peak load.

Below are graphs that depict resultant generation capacity and energy based on stakeholder specified assumptions utilized in the Business As Usual Scenario (F1S17).

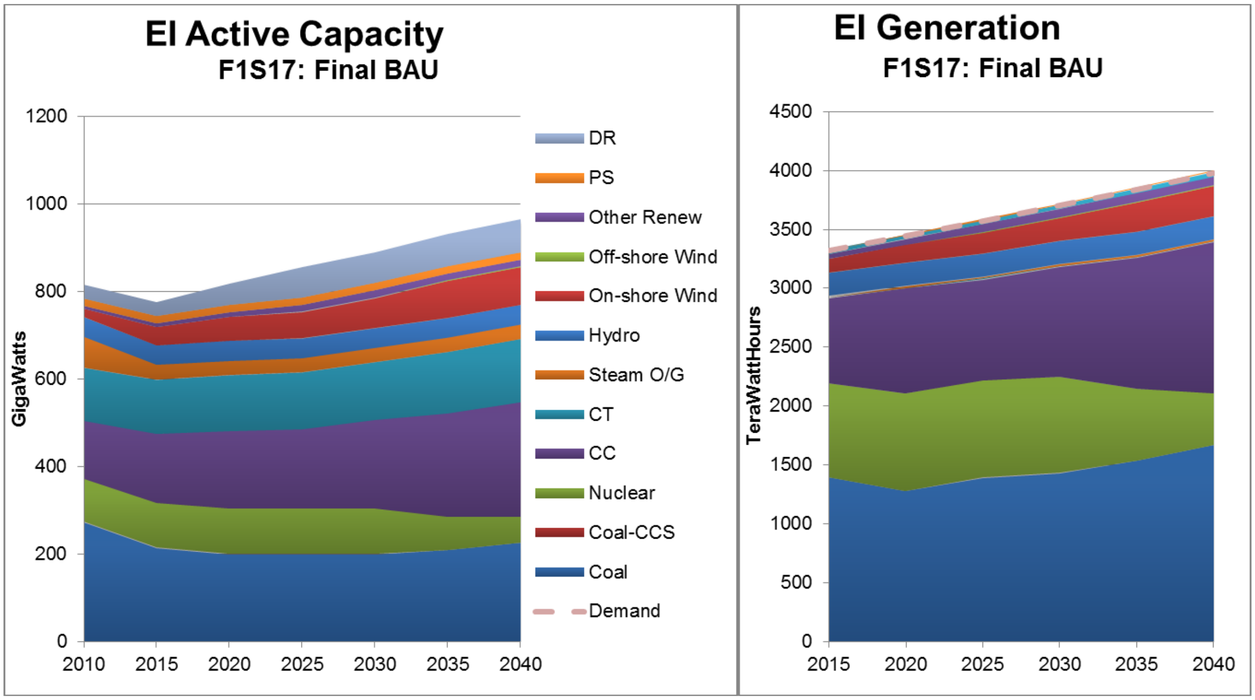

Figure 14: Scenario 3: Business As Usual (F1S17)

4.0 Conclusions and Observations

This report summarizes Phase 1 of the EIPC process. Key accomplishments are as follows:

- Stakeholders formed the SSC made up of sector and EISPC representatives from throughout the interconnection and adopted a governance structure.
- The EIPC Planning Coordinators undertook a formal roll-up review of their respective regional plans and performed reliability tests consistent with relevant NERC criteria.
- Using various analytical tools provided through the EIPC cooperative agreement, the SSC developed eight interconnection-wide resource futures with 72 sensitivities to be modeled.
- The SSC, after extended analysis and review, reached consensus on three fully developed future scenarios to be utilized by the Planning Coordinators for purposes of the high-voltage transmission buildout to be undertaken in Phase 2.

The EIPC project is notable as a first-of-its kind Eastern-Interconnection-wide transmission planning effort undertaken with the active involvement of State government officials and stakeholder representatives from throughout the Interconnection. The sheer size of the Eastern Interconnection, consisting of 39 U.S. states, six Canadian provinces, over 760,400 MW of generation and 620,000 MW of load underscores the scale of this effort. The Planning Coordinators note the considerable time and effort put into this project by stakeholders and by the state representatives of EISPC. The Planning Coordinators thank all of the participants as well as the state representatives and DOE for their support for this effort. EISPC would also like to take this opportunity to express its thanks to all of the EISPC members, especially those members who served on EISPC Committees, represented EISPC on the SSC and participated in EISPC and SSC work groups. EISPC is also grateful to Oak Ridge National Laboratory and other stakeholders as well as SSC members and Stakeholders who assisted EISPC in its Phase 1 work.

Phase 1 of the EIPC process has allowed for the development of significant enhancements to the analytical tools and processes used by stakeholders and policy makers to develop their three scenarios which form the basis for work under Phase 2 of the EIPC cooperative agreement. Phase 1 has also provided a valuable forum for stakeholders to interact and consider the respective priorities in their region. Work to date has allowed for an exchange of information among regions that should enhance the information considered in the regional planning processes.

It is appropriate to note important caveats governing the Phase 1 work product. At the outset, the EIPC effort was designed to provide high-level analysis of possible transmission buildouts associated with hypothetical future scenarios. The inputs to this process resulted from a substantial negotiation among diverse stakeholder interests spanning nearly the entire Eastern Interconnection. It was not intended to restrict these inputs to the bottom-up regional planning inputs that are used to produce actionable transmission plans.

The intent was to provide stakeholders and policy makers, within the limitations of the scope of this project, with an advance view of possible impacts that could result from policy decisions under consideration now and in the future. The end product of the effort will be a high-level interconnection-wide transmission analysis to be considered as appropriate in general policy making and regional planning.

The scenarios presented by the stakeholders are, by definition, high-level and hypothetical. The actual impact of any of the scenarios on a regional or sub-regional basis will depend on the exact circumstances and could be significantly affected by local conditions, events or policies which are simply not capable of being modeled given the high-level focus of the stakeholder-derived interconnection-wide futures. As such, this effort is not intended to be conveyed as a specific plan of action to fulfill any state policies or requirements and is not intended to be used as specific evidence in any State electric facility approval or siting processes. The work of the Eastern Interconnection States Council or the Stakeholder Steering Committee does not bind any State agency or Regulator in any State Planning proceeding.

In Phase 2 the EIPC Planning Coordinators will be undertaking a high-level analysis of a hypothetical transmission buildout associated with three future scenarios. The hypothetical buildouts will model additional transmission facilities, at the 230kV level and above, necessary to support the resultant generation resource expansion produced by the scenario. The scope of this work will be consistent with the uncertain nature of the inputs and the length of the planning horizon. The scope will also be consistent with the Eastern Interconnection-wide and interregional transfer focus of the planning effort. The analysis will not attempt to develop solutions for every related upgrade, which may be needed, particularly if system reconfiguration and/or smart grid applications are not considered in future extra high voltage (EHV) plans. That additional level of granularity would need to be developed at the respective regional planning processes consistent with actionable planning criteria and inputs that would develop as elements of a posited future in a region over time. Although the Planning Coordinators will be undertaking certain analyses to ensure that the hypothetical buildout at the 345kV and above is consistent with NERC reliability criteria, the project does not anticipate designing the transmission system to a level of granularity to address local conditions or upgrades that may be required to support assumed injections or associated transfers withdrawals. Moreover, any new hypothetical transmission lines developed do not represent specific transmission projects. The analysis is intended to provide information which may be utilized in a number of state, regional, interregional or interconnection-wide forums. For example, this information may be used to inform Planning Coordinators' Order 890-approved regional processes. Any projects ultimately developed will arise out of those regional processes where the appropriate level of study can be undertaken. In addition, any such projects will be subject to the approval process by each state’s siting authority in accordance with applicable law.

The three scenarios which have been selected by the SSC in Phase 1 represent three distinct stand-alone futures. Even though one is labeled “Business As Usual" (F1S17), the SSC decided to depart from the roll-up of the approved plans of each of the Planning Coordinators and remove certain generation and transmission projects that were part of those plans. Moreover, the decision of the SSC to utilize a forecast period through 2030 extended the baseline and the projects added or retired beyond the planning period currently utilized by Planning Coordinators in the Eastern Interconnection. At the time of the decision, the Planning Coordinators acknowledged that while such action was certainly within the rights of the SSC, such a departure would mean that the "Stakeholder Business As Usual" will no longer represent a baseline of those regional plans which have been approved, are NERC compliant, and are in the process of being implemented through the respective Order-890 approved processes. For these reasons, the stakeholder-driven SSI model represents a distinct future scenario, in and of itself, rather than a baseline of what projects would otherwise be developed by generators and transmission planners within the respective regions of the Eastern Interconnection. As such, each future is stand-alone and not incremental to any other. As the project moves into Phase 2, it is important to recognize this distinction between the roll-up of the existing plans and the new stakeholder-driven scenarios to avoid making improper characterizations as to whether any particular one is incremental to what would otherwise have occurred under the approved Order 890 plans of the Eastern Interconnection Planning Coordinators.

Although these caveats are important to an understanding of the limitations which, by definition, govern a project of this magnitude, they should neither be read as diminishing the notable accomplishments of the EIPC project to date nor the significance of this entire effort toward fostering interconnection-wide transmission analysis and communication among stakeholders, regulators and planners. That accomplishment alone is one in which all participants can take credit and for which DOE deserves praise in its vision and support for this project.

4.1 Process Topics

This section contains observations of the way in which this study was crafted, its processes, and its methodologies. These comments are not intended as criticism of this study nor the results produced. They are included here for consideration in the design of future study efforts. It is inevitable with a project of this magnitude and scope of analyses, conducted for the first time, that there are a number of aspects that would be done differently if the project were to be repeated. The purpose of this section is to capture some of those aspects. In many ways, the experience gained through completing the study may be more important than the specific analytical results. This is particularly true given that this is the first time an interconnection-wide planning study is being conducted with such a broad array of participants with an overarching goal to provide useful information to both the regional Planning Coordinators and to energy policy makers.

4.1.1 Reserve a Significant Portion of Modeling Runs

Contractual arrangements around the macroeconomic analysis limited the number of modeling runs that could be performed. As described earlier, these modeling runs were divided into futures and sensitivities. The SPWG initially intended to utilize the entire allotment of sensitivities for gathering information from adjustments to input assumptions. As the macroeconomic analysis proceeded, it became apparent that holding a portion of the sensitivities in reserve for other purposes would have had value. An example of this was the hardening sensitivities. The original plan was to proceed with the sensitivities with the transfer limits indicated through the soft constraint and transfer limit hardening methodologies. These indicated the location and size of interface expansions suggested by the model. Stakeholders learned that without performing a model run with the new transfer limits and making no other changes to input assumptions, attribution of the results could not be definitively associated with the input assumption change or the new transfer limits. Accordingly, some of the budgeted sensitivities were reserved for most futures in which stakeholders expanded the transfer limits.

4.1.2 Final Selection

Another group of sensitivities were ultimately reserved for selecting detailed scenarios to be used in Phase 2. Stakeholders selected the three final scenarios from approximately 80 choices. The negotiations inherent to this process resulted in a desire to synthesize policy futures that were not part of the originally envisioned modeling runs. Sensitivities were utilized at the end of Phase 1 to adjust input assumptions and to redistribute portions of anticipated generation expansion. As a result of these adjustments, the Phase 1 modeling encountered constraints in the number of available sensitivities. Future efforts might be able to minimize similar constraints by reserving more modeling runs earlier in the process.

4.1.3 Calibration

The conversion of some policy future goals into input assumptions also required the use of allotted sensitivities. For example, the goal of reducing carbon emissions was achieved in the model through a carbon tax mechanism. To identify the carbon price necessary to achieve the desired emissions reductions, the model was iteratively run under a series of carbon tax estimations. Future macroeconomic analyses of policy futures would benefit from a reservation of sensitivities for the conversion of goals into input assumptions.

4.1.4 Anticipate and Provide Clustering Analysis of the Results

To facilitate the scenario selection process at the end of Phase 1, an analysis of the modeling results performed to date became necessary. The package of results included scores of spreadsheets, each containing thousands of lines of data. With the assistance of the MWG, especially the technical experts from the Oak Ridge National Laboratory, the results were grouped into clusters. Graphical representations comparing two variables at a time were provided to stakeholders. While this valuable assistance enabled the development of some conclusions from the results, future efforts would benefit from a multi-variant analysis of the results to identify optimal scenarios. Adequate provision for a clustering analysis will enable greater levels of participation in the stakeholder process as well as the general public's comprehension of the results.

4.2 Observations and Guidance for Potential Future Studies

This section contains observations of the way in which this study was crafted, its processes, and its methodologies. These comments are not intended as criticism of this study nor the results produced. They are included for consideration in the design of future study efforts. It is inevitable with a project of this magnitude and scope of analyses, conducted for the first time, that there are a number of aspects that would be done differently if the project were to be repeated. The purpose of this section is to capture some of those aspects. In many ways, the experience gained through completing the study may be more important than the specific analytical results. This is particularly true given that this is the first time an interconnection-wide planning study is being conducted with such a broad array of participants with an overarching goal to provide useful information to both the regional planning authorities and to energy policy makers.

4.2.1 General

4.2.1.1 *Modeling Approach*

As described earlier, the allotment of modeling runs was separated into futures and sensitivities. The futures were designed to be significantly different from each other and accordingly had multiple differences in their input assumptions, constraints, and objectives. In contrast, the sensitivities were designed to comprise only one change to an input assumption from the base future to which it was associated. This approach allowed the stakeholders to attribute the difference in results to the single change in the input assumptions. Future efforts of this type would be well served to follow this paradigm as closely as possible.

4.2.1.2 *Working Relationship*

The study process benefited from an integrated working relationship between the Planning Coordinators, their consultants, EISPC and the SSC. Furthermore, the Planning Coordinators and their consultants were very careful to avoid influencing the SSC in developing input and strategic guidance for the study as envisioned in the SOPO. Given the Planning Coordinators' experience with modeling and knowledge of their systems, additional integration of the Planning Coordinators' advice and expertise into the process may have resulted in better facilitation of the modeling and scenario development. For example, EISPC drew upon the expertise of one of the Planning Coordinators in its early work. During its early meetings, EISPC received background information from a representative of one of the Planning Coordinators on resource planning processes, methods, and inputs. Since many of EISPC’s members did not have experience with these topics, this unbiased background information was beneficial to EISPC in its determination of required modeling scenarios and inputs. Drawing on existing expertise and experience during the formation of large projects such as this would likely benefit future studies.

4.2.1.3 *Integrating Generation and Transmission Analyses*

The study design separated future generation resource expansion analysis in Phase 1 from the transmission analysis in Phase 2. This separation understandably resulted in limitations on considering the interactions between generation choices and transmission choices. Furthermore, the study design was not intended to provide optimized results for such a distant point in time in the future. Nevertheless, some study participants expressed a desire for a study process that considers generation and transmission simultaneously, or iteratively, using optimization techniques. The level of effort needed to provide for such results, the availability of modeling tools, and the likelihood of being able to achieve the desired results on an interconnection-wide basis would need to be assessed before deciding to initiate work on such a study.

4.2.1.4 *Electric-Gas Interdependencies*

An observation that is similar to integrating generation and transmission analyses is that the study scope was appropriately limited to the electric transmission infrastructure to support the generation resource expansion futures for this initial interconnection-wide effort. Accordingly, the models used did not take into account potential natural gas infrastructure expansion needs for the gas generation projected in the various resource analyses. Accounting for those costs and the likelihood of gas infrastructure development could result in generation location changes, which in turn would alter transmission needs. Such an analysis of the natural gas infrastructure would require different types of models and expertise and would likely be a major effort in its own right.

4.2.1.5 *Structure and Sequencing*

After modeling a number of sensitivities during the resource analyses, it became apparent that many of the sensitivities made little difference in results. In retrospect, it would have been better to have designed the study with additional iterations between crafting the sensitivities, reviewing results, and crafting additional sensitivities. One specific example is that additional transmission sensitivities would have been valuable to stakeholders. Changing the amount of available transmission capacity at different levels would have provided interesting results in terms of the effect on generation location and type. In this regard, it is recognized that an appropriate balance would need to be struck between budget and schedule concerns and a process that would allow additional time for stakeholders to learn from initial results before specifying all of the future scenarios to be studied.

4.2.1.6 *Refinement of Assumptions*

The effects of EE and DR resources on the load forecast can influence transmission plans. Almost all transmission Planning Coordinators in the Eastern Interconnection reduce their overall load forecasts to reflect the impact of EE. The assumptions surrounding the modeling of DR vary more than the assumptions on EE. Developing additional information on these differences would require a separate study. However, that additional study is not required to perform interconnection-wide analysis of the transmission system. A potential modification to the modeling effort could be to have EE and DR selected by the model as resources rather than forced in.

4.2.1.7 *Stakeholder Process*

One of the challenges of the stakeholder process was that the policy agendas of different groups may have driven positions based on desired results for purposes beyond the original purpose of the study. Having neutral expertise available from the national laboratories was very helpful to the group in providing a reasoned basis for decisions. Also, the consensus-based structure of SSC governance, along with the ability to clearly caveat results and choices, helped parties with disparate views reach agreement. Greater regional balance on the SSC may have helped in that regard as well. In some ways, views seemed to be driven more by regional than by sector differences. In addition, future efforts would benefit from more equivalent levels of participation and process engagement throughout all regions.

4.2.1.8 *Load Growth Assumptions*

Annual regional load growth assumptions in the 2020 Roll-Up Integration Case varied from -0.63% to +3% per year. The Roll-Up Report contains explanations of the different load growth estimation processes, sources, years, and vintages along with other aspects. Developing additional information on these differences would require a separate study effort to explain and understand the depth and breadth of the details that go into creating the regional load growth assumptions. The level of effort needed to catalog and analyze those details and the relevant history surrounding them would need to be assessed before deciding to initiate such work. However, that additional study is not required to perform interconnection-wide analysis of the transmission system.

4.2.1.9 *Education*

The study helped to educate the participants about the different planning processes, assumptions, and methods used by transmission Planning Coordinators in the Eastern Interconnection. Providing additional depth to the education process would be beneficial in possible future study efforts.

4.2.1.10 *Choice of Model Year*

A model of the year 2020 was developed by the Planning Coordinators, based on their regionally developed plans for that year, as the starting point for interregional assessments of transmission system capabilities as provided for in Task 2 of the project. This model was labeled as the 2020 Roll-Up Integration Case because it started from the regionally developed plans, integrated them together, and then rolled them up into an interconnection-wide plan.

The 2020 year model, developed using a 2010 base or vintage year, contained cumulative generation and transmission expansion plans for the 10-year period.

Generally, projects that are forecast more than five years beyond the vintage year of the model may begin to lose some of the certainty associated with their implementation. Stakeholders developed a criteria of reasonable certainty to which they would subject projects shown as additions to the model in the years 2016-2020. Projects meeting the criteria remained in the model while those that did not meet the criteria were removed. This modified model became known as the Stakeholder Specified Infrastructure (SSI) model and served as the basis for the resource expansion futures selected by stakeholders.

The use of a shorter time horizon, such as five years, to establish an SSI model would add confidence, or reasonable certainty, that the model is a better representation of future conditions. However, it should be recognized that the process for developing the starting point year is only applicable for the purposes of an Eastern Interconnection study process and will have no direct effect on regional Order 890 planning processes or ongoing state siting proceedings.

4.2.2 Overload Charges

4.2.2.1 *Uniform Overload Charge*

As a high shadow price indicates greater economic value for transmission expansion relative to a low shadow price, using a percentage of the shadow price may indicate more expansion in areas with low shadow prices rather than ones with high shadow prices. In future studies, using a uniform shadow price, or one that is not set relative to the magnitude of the shadow price, may better align the model's incentives for transmission expansion with the economic value to be gained through congestion alleviation. The use of a uniform overload charge is a simple mechanism that would not indicate expansion in areas of minor shadow prices.

4.2.2.2 *Congestion Energy Overload Charge*

The overload charge design utilized in the Phase 1 macroeconomic analyses could be reviewed to determine if alternate approaches would yield results that align with different study objectives. The congestion energy method for setting the overload charge, described within this section, is based on the premise that overload charges should approach the shadow price where energy transfers occur infrequently. This method calculates overload charges based on simple area ($-hr) calculations.

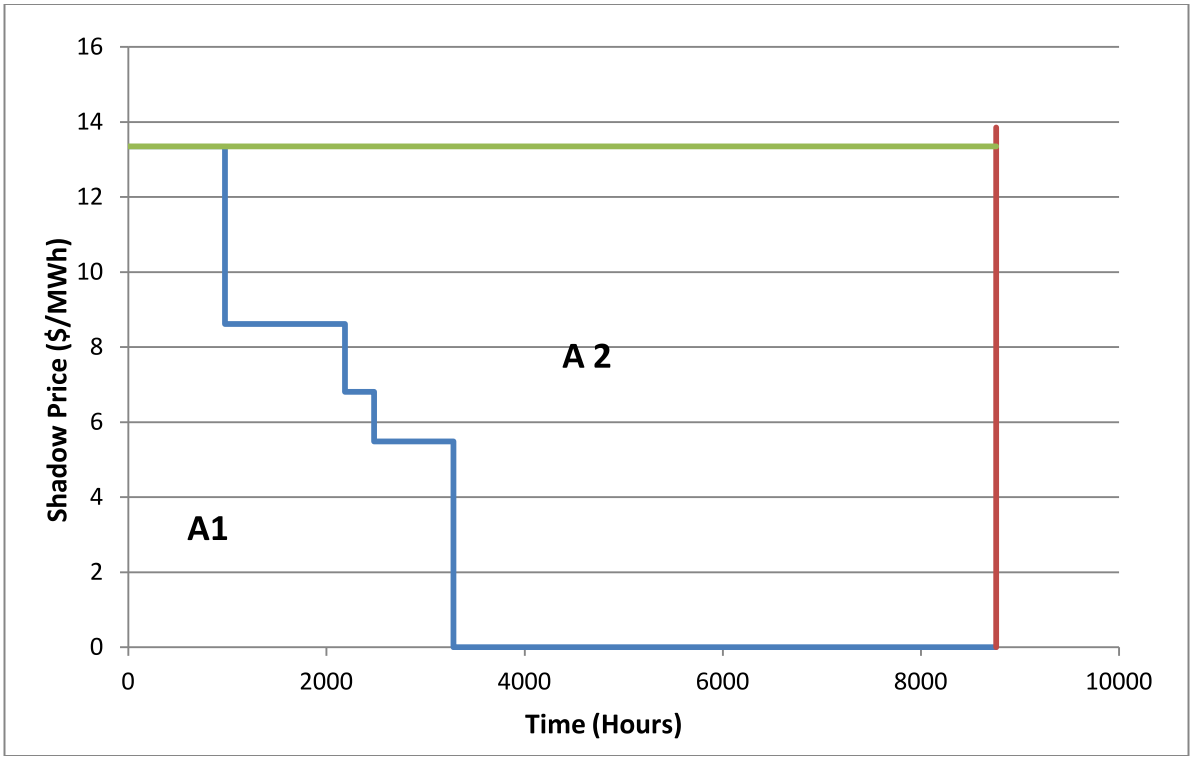

Figure 15: Overload Charge

As congestion energy represented by Area 1 (A1) in Figure 15 is low, the formula yields an overload charge that approaches the peak shadow price. As congestion energy grows in Area 2 (A2), representing no congestion, Area 1 (A1) becomes small thereby reducing the overload charge, which leads to greater interface expansion. Future studies might consider modifying the equation to reduce the resulting overload charge by a given proportion.

4.2.2.3 *Overload Charge Floor*

Another alternative to the design of overload charges that might be considered is the use of a floor, or minimum value, below which transmission expansion would not be indicated. Inclusion of a floor in the overload charge calculated in future studies would incorporate the principle that where congestion has not led to a significantly high shadow price, the economic value of increasing the transfer limit would not justify the expense. A floor is compatible with both a uniform overload charge and the congestion energy methods described above in Sections 4.2.2.1 and 4.2.2.2.

4.2.2.4 *Role of Transmission Costs and Production Cost Savings*

Future studies might also consider evaluating production cost savings enabled by transmission expansion. Each modeling run, including base cases and sensitivities, provides results on the total cost of serving energy demand. Within a particular future, where the difference between modeling runs can be reduced to a single input assumption, the cost differential between the base case and a sensitivity may provide an estimate of the savings or incremental expense. By comparing two runs that have different transfer limits, but otherwise have identical input assumptions, inferences may be made regarding the savings resulting from the expanded transfer limits. If this savings is then compared to the cost estimate associated with the transfer limit expansion, an approximation of cost-effectiveness may be possible. The details of how this approach might be implemented have not been developed and would need to be carefully considered before such a study is initiated.

5.0 Appendices

Appendix 1: EIPC Statement of Project Objectives (SOPO)
Appendix 2: EISPC Statement of Project Objectives (SOPO)
Appendix 3: "Soft Constraint Methodology"
Appendix 4: Transfer Limit Hardening Methodology Descriptions
Appendix 5: Modeling Electricity Flows from Hydro Quebec and the Maritimes
Appendix 6: Acronym List

Appendix 1: EIPC Statement of Project Objectives (SOPO)

EIPC Statement of Project Objectives (SOPO)

PJM Interconnection, L.L.C.

STATEMENT OF PROJECT OBJECTIVES

Recovery Act: Eastern Interconnection Planning Collaborative (EIPC)
Topic A

A. Objectives

NOTE: Topic A involves the Interconnection-Level Analysis and Planning. Topic B includes the cooperation among states, with input from stakeholders, on electric resource planning and priorities. The work being performed under this Cooperative Agreement is work designated under Topic A.

The objective of this project is to address the Eastern Interconnection Topic A efforts to prepare analyses of transmission requirements under a broad range of alternative futures and develop long-term interconnection-wide transmission expansion plans in response to the alternative resource scenarios selected through the stakeholder process. The process does not supplant the existing FERC Order 890 approved regional planning processes, rather the information gained from this project should help inform the 890 regional processes going forward. The Recipient will perform analysis and planning for the Eastern Interconnection in a transparent and collaborative manner that is open to participation by state and federal officials, representatives from independent system operators (ISOs) and regional transmission organizations (RTOs), utilities, and relevant stakeholder bodies or non-government organizations (NGOs), including appropriate entities in Canada, with an approach to ensure consensus among stakeholders on key issues.

This work will be completed and funded by a single Budget Period; two Phases will exist, separated by a GO/NO GO Decision. During Phase 1, the Recipient will 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 will also serve as a reference case for modeling various alternative grid expansions based on the scenarios developed by stakeholders. In addition, macroeconomic analyses will be performed by the Recipient to assist the stakeholders in development of the scenarios to be analyzed in Phase 2. During Phase 2, the Recipient will perform transmission scenario analysis as guided by broad stakeholder input and the consensus recommendations of the Stakeholder Steering Committee (SSC) to aid federal, state, and provincial regulators; other policy makers; and other stakeholders in assessing interregional options and policy decisions.

B. Scope of Project

This project will use a collaborative approach to conduct interconnection-wide analysis and planning. The Recipient, along with other Eastern Interconnection Planning Authorities, created a new collaboration of planning entities called the Eastern Interconnection Planning Collaborative (EIPC). Through the EIPC, the Recipient will prepare analyses of transmission requirements and develop long-term interconnection-wide transmission expansion plans. To accomplish the objectives of this project, the Recipient will:

- Give appropriate attention to the merits of alternative configurations of the interconnection's Extra High Voltage (EHV) Alternating Current (AC) and Direct Current (DC) network;
- Establish a multi-constituency Stakeholder Steering Committee (SSC) that will provide strategic guidance to the scenarios to be modeled, the modeling tools to be used, key assumptions for the scenarios, and other essential activities; at least one-third of the members of the SSC shall be state officials;
- Make available to the public the modeling tools and databases used and developed under this project, and open all events and meetings of study groups;
- Provide resources to enable representatives of relevant non-profit NGOs to participate in the development of interconnection-level analyses and plans;
- Satisfy all reliability standards approved by FERC while achieving and balancing the following:
    - Consider all available technologies (to the extent that they may become economic) for electricity generation, energy storage, transmission, end-use energy efficiency, demand resources, and management of transmission- and distribution-level facilities;
    - Satisfy all current state and federal requirements (as of the date of the analysis underlying the plan(s)) for renewable energy goals, energy efficiency goals, and goals for reducing greenhouse gas emissions;
    - Analyze the long-term costs of producing and delivering electricity to consumers;
    - Analyze the overall long-term impacts of electricity supply activities on the environment; and
    - Provide a path for efficient grid development; e.g., build fewer but larger long-distance transmission lines.

This project will aggregate modeling and regional expansion plans developed in the annual regional processes for 2010, and will conduct base plan and scenario analysis to identify potential impacts and interregional transmission expansion options. This project will provide the initial results of the analysis to stakeholders and the SSC and complete a formal commenting process with stakeholders on the results. The resulting Eastern Interconnection transmission model developed by integrating the regional plans will be analyzed to identify opportunities for potential transmission enhancements to regional expansion plans in order to increase the ability to move power or reduce costs. In Phase 2, the Recipient will provide the results of the reliability and production cost analyses performed for the resource expansion scenario(s) selected for further study, including the interregional transmission expansion options identified and the associated cost estimates. This project will facilitate meetings with the associated regional planning entities to provide this input for use in their subsequent planning processes. This project will provide for an EIPC website to publicize analysis results, modeling, work papers, and other materials, subject to applicable regulations associated with licensing requirements and protection of Critical Energy Infrastructure Information (CEII) and Confidential Data.

C. Tasks and Subtasks to Be Performed

Task 0. Project Management and Planning

The Recipient will revise the Project Management Plan (PMP) to include details from the final cooperative agreement and revised project schedule and milestone dates. The approach, tools, and techniques will be revised as necessary along with project timeline and milestones.

The Recipient will revise the PMP periodically throughout this project as needed to reflect the results of work completed and the changes necessary to accomplish objectives in accordance with project delivery dates. Quarterly reporting on schedule progress, actual expenditures versus budget, and revised expenditure projections will be reflected in the PMP updates.

Phase 1

Phase 1 will focus on establishing group structures, methodology development, macroeconomic sensitivity development, and interregional analysis of the regional plans.

Task 1. Initiate Project

The Recipient shall meet with the Eastern Interconnection Topic B Recipient and stakeholders to assess potential adjustments needed in the process for selecting the SSC or study team structures. The Recipient will update or establish study processes as required. The Recipient will facilitate the formation of the SSC, stakeholder working groups (SWGs), and any necessary subgroups. The SWGs will be responsible for facilitating the interchange of information between the broader stakeholder community, the SSC, and the Recipient.

The Recipient will conduct a series of regional stakeholder meetings to timely communicate this project's structure, processes, and deliverables; work toward the establishment of the SSC and selection of representatives from multiple constituencies; and initiate work toward consensus on scenarios for analysis. The Recipient will conduct webinars and conference calls to facilitate timely input from the broader stakeholder community and the SSC regarding project tasks.

Subtask 1.A Adjust structure of SSC as needed.
Subtask 1.B Commission SSC.
Subtask 1.C Select SSC members.
Subtask 1.D Establish SSC By-Laws, elect officers.
Subtask 1.E Project task and scope development.
Subtask 1.F Develop process for selection of NGOs and Consumer Advocate (CA) groups.

Task 2. Integrate Regional Plans

The Recipient, building upon the existing regional plans of the NERC Planning Authorities within the Eastern Interconnection, will aggregate and update the modeling required to perform Interregional Analysis for the entire Eastern Interconnection. This modeling will serve as the basis both for the Interregional Analysis of the existing regional plans and for the expansion scenario analysis selected by stakeholders through the SSC. Interregional Analyses will include contingency analysis, transfer analysis, and other reliability assessments performed on an interregional basis to identify potential conflicts among regional plans and opportunities for efficiencies in transmission expansion.

This integration and Interregional Analysis will assess compatibility among the regional plans; which are developed to meet all current state, provincial, and federal regulatory and reliability requirements; and will identify potential opportunities to enhance the regional plans across regions. Key inputs for Task 2 include the existing regional plans and the Eastern Interconnection Reliability Assessment Group's (ERAG's) Multiregional Modeling Working Group's (MMWG's) modeling.

Subtask 2.A Develop study guide for documenting Interregional Analysis processes that refine the MMWG modeling and regional plans as needed for Roll-up Integration Case analysis.
Subtask 2.B Conduct interregional transmission analyses for Roll-up Integration Case and identify potential transmission conflicts/opportunities among regional plans; e.g., gap analysis.
Subtask 2.C Develop transmission options to address reliability impacts associated with potential conflicts among regional plans.

Subtask 2.D Document and communicate results for consideration in regional planning activities and post the analysis on the EIPC website.
Subtask 2.E Develop flowgates.

Task 3. Production Cost Analysis of Regional Plans

The Recipient will perform economic analysis of the integrated regional plans using production cost modeling. Production cost analysis will assess all hours of the future year and will forecast energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors. The production cost analysis will be performed for multiple future sensitivities such as high/low loads, high/low fuel costs, high/low carbon taxes, or similar parameters.

The Recipient will perform the production cost analysis using a model that simulates the hour-by-hour operation of the transmission and generation system in the Eastern Interconnection, incorporating transmission reliability and environmental considerations. The analysis will quantify economic and environmental impacts under multiple sensitivities including changes in costs, prices, emissions, and reliability. The Recipient will utilize a model that uses a highly detailed database of generation and transmission facilities in the Eastern Interconnection, which will be refined using input from EIPC members and stakeholders. Any changes to this model may impact the project performance, cost, and schedule. Key inputs for Task 3 include the interregional modeling generated in Task 2.

Subtask 3.A Perform production cost modeling for the Roll-up Integration Case.
Subtask 3.B Document and communicate results of production cost modeling and post the analysis on the EIPC website.

Task 4. Macroeconomic Futures Definition

The Recipient will conduct meetings to generate strategic guidance from the SSC toward developing a set of macroeconomic sensitivities that will be analyzed and compared. The Macroeconomic Analysis will be conducted for up to eight different futures, with up to nine sensitivities performed for each future. The selection of different futures to be considered in the Macroeconomic Analysis will be determined by the SSC. The Recipient will allow the Topic B Recipient to select a certain number of the eight futures for the Macroeconomic Analysis.

The Recipient will assist and inform the SSC and SWGs to aid the SSC in reaching consensus on these sensitivities. The SSC and SWGs will gather and synthesize input from the broader stakeholder community on inputs and implications of the Macroeconomic Analysis and other phases of the analysis. The Recipient will provide resources to facilitate the ongoing interchange between the SSC, SWGs, and the broader

stakeholder community. For the Macroeconomic Futures, the Recipient will coordinate with the SSC to identify and develop the various inputs needed to perform the Macroeconomic Analysis and other modeling assumptions. The Recipient will inform the SSC of the modeling tools and analysis methods planned for performing the work in connection with the Macroeconomic Analysis, explain their operation, inputs and outputs, and appropriately include strategic guidance received from the SSC.
The macroeconomic sensitivities are intended to provide the SSC, stakeholders and policy makers a forecast of how the interconnected electrical system might evolve for a range of potential policy and economic futures. For example, a set of macroeconomic sensitivities selected by the SSC might be a 20% Renewable Energy Standard (RES) under high, medium, and low fuel costs. Another set might be a 20% RES with $30 carbon allowances under high, medium, and low fuel costs. Such analysis will show potential renewable resource development, impacts on loads, emissions reductions, energy exchanges between regions, and other metrics of interest. These analyses will provide useful information to the SSC in determining the expansion scenarios to be chosen in Task 6. Key inputs for Task 4 include the SSC formation and stakeholder input, both from Task 1.

Subtask 4.A Complete initial macroeconomic sensitivities definitions.
Subtask 4.B Coordinate and conduct initial stakeholder regional meeting(s) to develop consensus on resource expansion scenarios.

Task 5. Macroeconomic Analysis

The Recipient will provide Macroeconomic Analyses for up to eight futures, with up to nine sensitivities for each future to provide a high-level assessment of the outcomes of numerous proposed scenarios to be determined by the SSC at the start of Phase 2. To help inform their decisions, the SSC will receive high-level results such as economics of resources in various regions, impacts on renewable development, impacts on emissions, impacts on economic development and demand, and other factors.

The Recipient will perform the Macroeconomic Analysis using a model that considers impacts both to the electric power supply and to the other sectors of the US economy. Because the macroeconomic approach accounts for all sectors of the economy and not just electric power, it also conveys potential impacts on electric demand and prices that may result related to energy policy impacts in other areas of the economy. Any changes to this model may impact the project performance, cost, and schedule.

The Recipient will provide high-level transmission analysis for the sensitivities of interest indicated by the SSC. This analysis will not be detailed power flow analysis, but rather conceptual assessments made by the Planning Authority engineers of potential interregional transmission expansion to support the magnitude of interregional energy exchanges identified in the Macroeconomic Analysis sensitivities. The Macroeconomic Analysis will provide the SSC with information regarding potential resources in other regions and associated interregional energy exchanges that may be desirable under certain policy or economic futures. Key inputs for Task 5 include the SSC's consensus from Task 4.

Subtask 5.A Coordinate and conduct SSC meeting(s) to finalize consensus on resource expansion scenarios.
Subtask 5.B Conduct Macroeconomic Analysis and high-level transmission analysis.
Subtask 5.C Review results of analyses with the SSC.
Subtask 5.D Facilitate conference calls to review the results and provide for SSC interaction and discussion.

Task 6. Expansion Scenario Concurrence

The Recipient will develop Expansion Scenario(s) of interest which provide a platform for the SSC to consider higher levels of energy exchange between regions than may be included in existing regional plans. The Recipient will develop proposed scope documents for the Expansion Scenario(s) based upon the input received from the SSC during development and review of the Macroeconomic Analyses in Tasks 4 and 5. The range of resource options that the SSC will choose from may include those that are not currently feasible but could become feasible in coming decades. These could include additional energy efficiency; demand response; combined heat and power (CHP); clean coal/carbon capture and storage (CCS); advanced nuclear; renewables such as wind, central solar, rooftop solar, geothermal (hydrothermal, geo-pressured, co-production/low-temperature, enhanced geothermal systems), bio-power, water (incremental and new hydroelectric, ocean, hydrokinetics, pumped storage); and other storage technologies.

The Recipient will incorporate state and load serving entity inputs in developing the level of external resources (imports) to be assessed for each area and/or the level of resources sited within each area to be assessed for exports to other areas. State input is anticipated to be provided by state authorities consistent with state processes for making resource selections. One state or region shall not impose resource assumptions on another state or region in developing the scope outside of a consensus among the states. The Recipient will review the proposed scope documents with the SSC to receive strategic guidance and adjust the scopes as appropriate. One of the three Expansion Scenarios will meet the Topic B Recipient's requirements.

A draft Part I report will be developed by the Recipient and provided for SSC and stakeholder review prior to the regional stakeholder workshop(s). The Recipient will conduct regional stakeholder workshop(s) to present the results of the analysis, respond to questions, and solicit input from stakeholders. The SSC, taking into consideration the input from the workshop(s) and other stakeholder venues, will provide consensus-based comments on the draft report. Key inputs for Task 6 include the Macroeconomic

Analysis and high-level transmission analysis results from Task 5, individual state and load serving entity resource guidance on the level of external resources (imports) to be addressed for each region, and SSC inputs from Tasks 4 and 5.

Subtask 6.A Obtain Expansion Scenario Concurrence.
Subtask 6.B Prepare Phase 1 Report: Reference Case and Expansion Scenarios.

A GO/NO GO Decision will be made by the DOE Project Officer based on the results of the Phase 1 efforts. The Recipient shall not proceed to Phase 2 without written approval of the DOE Project Officer. Within 10 days of receipt of the Phase 1 Report, the DOE Project Officer will provide written notification to the Recipient of the decision. In the event the project does not proceed beyond Phase 1, the maximum DOE liability to the Recipient is the funds available in support of the project effort up to and including Phase 1 and closeout costs.

Phase 2

The Recipient will perform reliability and production cost analyses of alternative transmission options to support the expansion scenarios selected during Phase 1. High-level cost estimates will also be developed for both the generation and transmission expansion facilities for each scenario.

Task 7. Interregional Transmission Options Development

The Recipient will modify the Eastern Interconnection modeling developed in Task 2 to build interregional expansion models. This task will focus on transmission reinforcements to support the interregional energy exchanges for each of the Expansion Scenario(s) from Task 6. The Recipient will develop transmission expansion options focused on the EHV transmission network (230 kV and above), and will also consider operating options and other potential solutions. The Recipient will consider the transmission facilities required to integrate new resources within a region using a similar high voltage focus, but will not attempt to resolve potential local transmission issues. The Recipient will leverage the expertise of EIPC's membership in considering high voltage direct current (HVDC) and advanced technologies in developing expansion options.

The Recipient will identify transmission expansion options for each Expansion Scenario and the associated solved Eastern Interconnection modeling necessary to perform reliability and economic analyses. The transmission expansion options will align with the future study period; e.g., 10, 15, or 20 years; selected for the Expansion Scenarios. This project will not identify specific routing, siting, environmental, or other related issues associated with any potential enhancements to the grid.

The Recipient will conduct stakeholder outreach and meetings to share preliminary results of potential transmission reinforcements needed to support the Expansion Scenarios and solicit input from the SSC and other stakeholders. Key inputs for Task 7 include the Expansion Scenarios from Task 6 and the Eastern Interconnection modeling from Task 2.

Subtask 7.A Develop and/or adjust transmission reinforcements needed to support the Expansion Scenarios.
Subtask 7.B Develop Eastern Interconnection model for each scenario.

Task 8. Reliability Review

The Recipient will perform reliability analyses consistent with NERC reliability criteria for transmission planning to assess in aggregate for the Eastern Interconnection the interregional transmission options developed in Task 7. Key inputs for Task 8 include the Eastern Interconnection models from Task 7.

Subtask 8.A Perform reliability analysis for each scenario.
Subtask 8.B Review Detailed Transmission Analysis results with the SSC and stakeholders.
Subtask 8.C Develop flowgates.

Task 9. Production Cost Analysis of Each Scenario

Economic analysis will be performed using production cost modeling for each scenario based upon the power flow modeling and transmission expansion options developed in Task 7. Consistent with Task 3, production cost analysis will assess all hours of a future year and will forecast energy production costs, constraints limiting dispatch and interregional transactions, anticipated emissions, renewable energy production, and other pertinent factors. The production cost analysis will be performed for multiple future sensitivities such as high/low fuel costs, high/low carbon taxes, and similar parameters using the same analysis tool as utilized in Task 3. Any changes to this model may impact the project performance, cost, and schedule. Key inputs for Task 9 include the Eastern Interconnection models from Task 7 and flowgates identified during Task 8 analysis.

Task 10. Generation and Transmission Cost Development

During Task 10, the Recipient will provide high-level estimates of the capital costs of the interregional generation resource and transmission expansion options considered. Transmission costs will be developed by the Recipient using generic planning-type estimates referenced to the study year and will represent “overnight” costs. “Overnight” assumes the facilities could be built and placed in service in a given year and does not include significant financing costs for construction work in progress. Costs associated with resource additions and retirements will be developed by the Recipient and will be informed by SSC assumptions regarding technology characteristics and costs. Key inputs for Task 10 include the Interregional Expansion Options (generation and transmission) from Tasks 6 and 7, and high-level, generic cost information such as dollar per mile estimates for transmission lines rather than detailed cost estimates based on specific route selection and engineering designs.

Task 11. Review of Results

The Recipient will develop a draft Phase 2 report and provide it for SSC and stakeholder review. The Recipient will conduct regional stakeholder workshop(s) to present the results of the analysis, respond to questions, and solicit input from stakeholders. The SSC, taking into consideration the input from the workshop(s) and other stakeholder venues, will provide consensus-based comments on the draft report. Key inputs for Task 11 include results from Tasks 1 through 10.

Subtask 11.A Review results and develop first draft of Phase 2 report.
Subtask 11.B Review results with SSC and solicit input on the draft report.
Subtask 11.C Review report during workshop with stakeholders.

Task 12. Phase 2 Report

The Recipient will review the input received from the SSC and address it in the final Phase 2 report. In addition to the final report, associated modeling, databases, and other work products will be made available electronically during this project through the EIPC website, subject to legal and regulatory requirements for CEII and treatment of Confidential Information. Key inputs for Task 12 include the draft report and stakeholder input from Task 11.

Subtask 12.A Incorporate stakeholder feedback and prepare final Phase 2 report; post report on EIPC website.

D. Deliverables

The periodic, topical, and final reports will be submitted in accordance with the attached "Federal Assistance Reporting Checklist" and the instructions accompanying the checklist.

In addition to the deliverables identified in the Federal Assistance Reporting Checklist, the Recipient will submit the following reports to DOE within 30 calendar days of the completion of the respective Task:

Task 0. Project Management and Planning

- Revised, detailed Project Management Plan
- Coordination document developed in concert with Eastern Interconnection Topic B Recipient identifying coordination points throughout the projects and coordination of deliverables involving each Recipient

Phase 1

Task 1. Initiate Project

- Stakeholder Meetings Materials – Meeting materials include items prepared for the meeting such as agendas and presentations as well as materials generated as a result of the meeting including participant lists, minutes, formal decisions, etc.
- SSC By-Laws
- SSC Roster
- SWG Roster(s)
- Project Task Scopes
- NGO and CA Selection Process

Task 2. Integrate Regional Plans

- Study guide for Interregional Analysis processes
- Roll-up Integration Case
- Interregional Transmission Analysis for Roll-up Integration Case
- Transmission expansion options to address conflicts among regional plans
- Documentation that results have been communicated to regional planning authorities for use in future regional planning activities
- List of flowgates to be used in production cost analysis

Task 3. Production Cost Analysis of Regional Plans

- Production cost analysis results

Task 4. Macroeconomic Futures Definition

- Consensus from SSC on futures for Macroeconomic Analysis
- Stakeholder regional meeting(s) materials – Meeting materials include items prepared for the meeting such as agendas and presentations as well as materials generated as a result of the meeting including participant lists, minutes, formal decisions, etc.

Task 5. Macroeconomic Analysis

- Macroeconomic Analysis results for Resource Expansion Scenarios
- High-level transmission analysis

Task 6. Expansion Scenario Concurrence

- Description of Expansion Scenario Concurrence
- Phase 1 Report

Phase 2

Task 7. Interregional Transmission Options Development

- Interregional transmission expansion options to support Expansion Scenarios
- Eastern Interconnection model for each scenario
- Stakeholder regional meeting(s) materials – Meeting materials include items prepared for the meeting such as agendas and presentations as well as materials generated as a result of the meeting including participant lists, minutes, formal decisions, etc.

Task 8. Reliability Review

- Reliability assessments of interregional transmission expansion options that support Expansion Scenarios
- List of flowgates to be used in production cost analysis

Task 9. Production Cost Analysis of Each Scenario

- Production cost analysis results

Task 10. Generation and Transmission Cost Development

- High-level cost estimates for expansion option facilities

Task 11. Review of Results

- Draft Phase 2 report
- SSC and stakeholder input on draft report

Task 12. Phase 2 Report

- Final Phase 2 report
- Related work papers

E. BRIEFINGS/TECHNICAL PRESENTATIONS

The Recipient shall provide and make presentations on the results of this work at the DOE Annual Review Meeting to be held at either the NETL facility located in Pittsburgh, PA or Morgantown, WV; or other location specified by the DOE Project Officer.

The Recipient shall provide and make presentations on the results of this work at the DOE Peer Review Meeting to be held at either the NETL facility located in Pittsburgh, PA or Morgantown, WV; or other location specified by the DOE Project Officer.

Appendix 2: EISPC Statement of Project Objectives (SOPO)

STATEMENT OF PROJECT OBJECTIVES

Eastern Interconnection States' Planning Council (EISPC)
The National Association of Regulatory Utility Commissioners (NARUC) – TOPIC B

A. Objectives

NOTE: Topic A involves the Interconnection-Level Analysis and Planning. Topic B includes the cooperation among states, with input from stakeholders, on electric resource planning and priorities. The work being performed under this Cooperative Agreement is work designated under Topic B.

The objective of this project is to address Eastern Interconnection Topic B efforts to provide for cooperation among states on electric resource planning and priorities. As part of this project, the Recipient 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.

B. Scope of Project

This project will use a collaborative approach to facilitate coordination and consensus-building around interconnection-wide transmission planning. The Recipient will create and operate a new collaboration among state and provincial representatives, including utility regulatory commissions and governors' offices. The Recipient will employ staff to support this collaboration, the Eastern Interconnection States' Planning Council (EISPC), and provide for their day-to-day operations. Through the EISPC, the Recipient will facilitate dialogue and collaboration among the states and provinces 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 Topic A. To accomplish the objectives of this project, the Recipient:

- Will identify Eastern Energy Zones of particular interest for low- or no-carbon electricity generation; e.g., renewable-rich areas with suitable topographic and other characteristics for either variable or baseload generation, including but not limited to non-terrestrial areas particularly suited to offshore wind and ocean power technologies, areas with geology or other characteristics particularly suited to carbon capture and sequestration (CCS), or areas otherwise particularly suited to other forms of low- or no-carbon electricity generation. The Recipient will allow for regional diversity and determine how the identification of Eastern Energy Zones could best serve the collective interests of the affected states.

- Will conduct studies on key issues related to reliable integration of variable renewables into the Eastern Interconnection, studies on availability of baseload renewables and other low-carbon resources, as well as other studies needed to better enable member state participation in regional and interconnection-wide analyses and planning.
- Will develop other inputs as needed to go into the interconnection-level analyses prepared under the Eastern Interconnection Topic A work.
- Will 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.
- Will 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. This process shall be open to all relevant technologies and afford ample opportunity for participation by state governors, provincial ministers, their designees, and state or provincial utility regulatory officials.

C. Tasks and Subtasks to Be Performed

Task 1. Organizational development and project management

Develop the new organization including establishing decision-making processes and protocols, staffing needs, budget requirements, institutional arrangements to ensure expert and infrastructural support of the new staff, and methods to ensure the accountability of the staff. Revise and maintain the Project Management Plan and manage and report on activities in accordance with the Plan. Subtasks include the following:

Subtask 1.A Form an Executive Committee.
Subtask 1.B Develop EISPC organizational structure and operating protocols.
Subtask 1.C Hire EISPC staff and set up of office space.
Subtask 1.D Identify key stakeholders that need to be involved in the collaborative effort, revise and maintain the Project Management Plan, assess issues such as the ability to obtain and protect confidential information among the Eastern Interconnection Topic A and Topic B Recipients required to conduct the studies.

Task 2. Reach consensus on the Recipient’s position on modeling inputs and assumptions via expansion of transmission planning knowledge base

The Recipient will, utilizing internal and external expertise in concert with newly hired staff, expand the current transmission planning knowledge base to incorporate the diversity of the entire Eastern Interconnection to enable development of EISPC's position on initial inputs and assumptions. This will enable the Recipient to provide pertinent feedback on the Roll-up Integration Case and Recipient's positions on scenarios that will be based on a public policy standpoint.

Subtask 2.A Define recommendations for the "Planning Horizon;" e.g., 10, 15, 20, 30, 50 years; for the various scenarios.

Subtask 2.B Define recommendations for parameters for a "Reference Case," that may include the following:

- Recommendations for the "Reference Case" and determine if the Recipient will consider it the "Business as Usual Case."
- At what point in the planning process the Recipient recommends a resource be included in the "Reference Case," as opposed to a future case.
- Recommendations for how pending legislation or rulemakings should be addressed in the "Reference Case."
- The Recipient's definition of current renewable or alternative energy zones in the Eastern Interconnection.

Subtask 2.C Compile energy and demand forecasts to be available for use by the Eastern Interconnection Topic A Recipient including the Recipient's evaluation of the forecasts for credibility and consistency as well as the various forecasting methodologies.

Subtask 2.D Assess such variables as fuel escalation rates, forecasted increases in fixed costs associated with construction of new facilities, forecasted maintenance costs, forecasted rates of inflation and capital costs, etc.

Subtask 2.E Catalogue current demand side resources; i.e., demand response, price response, and energy efficiency programs; and distributed generation resources and their effect on energy and demand forecasts and the attendant affects on production costing and resource planning.

Subtask 2.F Determine Recipient's positions concerning environmental costs; e.g., NO_X, SO_X, mercury, carbon, and water; and catalogue existing and potential environmental exclusionary zones.

Subtask 2.G Define "renewable" and/or "alternative" resources to ensure consistent treatment in the Recipient's studies. Compile Renewable Resource Standards for each state and make every effort to achieve a consensus position on the treatment of "Renewable Energy Credits" in the conduct of the Recipient's studies.

Subtask 2.H Determine Recipient's position on the treatment of retirements of resources; e.g., due to more stringent environmental rules, age, condition.

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

The Recipient will assemble data in preparation of receipt of the Roll-up Integration Case and Production Cost Analysis from the Eastern Interconnection Topic A Recipient. The Recipient will develop a consensus position on the Eastern Interconnection Topic A Recipient's Roll-up Integration Case. The Recipient will refine their position on inputs and assumptions as necessary.

Task 4. Conduct studies to facilitate further refinement of the modeling inputs and future scenarios

The Recipient will complete several studies on key issues related to reliable integration of variable renewables into the Eastern Interconnection, studies on availability of baseload renewables and other low-carbon resources, as well as any other studies needed to better enable state participation in regional and interconnection-wide analyses and planning. The Recipient will first begin the study to identify Eastern Energy Zones of particular interest for low- or no-carbon electricity generation. The Recipient will conduct additional studies. The list of potential additional studies includes the following:

- Identification of state-by-state potential for renewable or alternative energy; e.g., wind, solar, biomass, landfill, hydro, etc.; as well as imports from Canada.
- Assessment of the location of new nuclear facilities and uprating existing nuclear resources.
- Assessment of coal potential including carbon capture and storage.
- Identification of state-by-state potential for demand-side resources including price responsive demand, peak demand management (including customer-owned energy storage), and energy efficiency.
- Identification of state-by-state potential for distributed generation.
- Assessment of state-by-state potential for storage and waste-to-energy facilities.
- Assessment of state-by-state potential for rapid-startup fossil back-up generation.
- Assessment of gas and other fuel price issues.
- Other issues as identified by the Recipient.

Task 5. Preparation of Whitepapers

The Recipient will prepare several whitepapers during this project to assist in the development of its position on modeling inputs and evaluation of future scenarios. The list of potential whitepapers includes the following:

- Renewable/Alternative Energy Whitepaper – This whitepaper at a minimum will attempt to estimate the potential Renewable Energy Values that the Recipient will recommend be used in the formulation of scenarios and the effect on resource selection.
- Market Structures Whitepaper – This whitepaper will identify relevant market structures on a state and regional basis (particularly in the economic context) for new resource development. It may also describe transmission planning processes and responsibilities used within each market context and evaluate the potential impact on market development of an interconnection-wide planning and development.
- Power Purchase Agreements for Renewables Whitepaper – This whitepaper will investigate the financial implications for regulated utilities due to substantial purchases of power from renewable or alternative energy sources.
- State, Regional, and Federal Policy Whitepaper – This whitepaper will catalog the existing state, regional, and federal policies that may impact transmission planning and development.
- Smart Grid Whitepaper – This whitepaper will identify the potential for smart grid in the development of one or more scenarios.
- Plug-In Hybrid Electric Vehicle (PHEV) Whitepaper – This whitepaper will describe the future potential for PHEVs in one or more scenarios.
- Policy and Legislative Considerations Affecting the Economics of Infrastructure Investment Whitepaper – This whitepaper will consider economic uncertainties, risk, and potential impacts on resource expansion plans, as well as state statutes and rules that may ameliorate or increase uncertainties such as Construction Work In Process/Allowance for Funds Used During Construction (CWIP/AFUDC), recovery of costs associated with emerging technologies such as nuclear and clean coal, and state-specific economic incentives or disincentives.
- Incentives and Policies Driving Energy Resource Development Whitepaper – This whitepaper will consider other incentives and disincentives for resource development including “traditional” generation technologies, distributed generation, transmission, renewable or alternative energy, demand-side management (DSM), energy storage, Smart Grid, etc.

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

Utilizing information from the Eastern Interconnection Topic A Recipient, the Recipient will achieve consensus on its position concerning the future scenarios for macroeconomic analysis to be conducted by the Eastern Interconnection Topic A Recipient. The Recipient will consider changes in legislation, the economy, technology, and external factors during the consensus process.

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

The Recipient will develop a consensus on its position for the final transmission build-out scenarios to be conducted by the Eastern Interconnection Topic A Recipient. The Recipient will revise and finalize it positions related to the deliverables provided by the Eastern Interconnection Topic A Recipient's efforts. The Recipient will consider the whitepapers and studies developed as part of this project to inform the evaluation of scenarios. This will include reliability and economic implications of various resource portfolio scenarios factoring in the potential for reduced reserve margins, reducing congestion and losses resulting from potential new transmission, upgrades of existing facilities, and enhancements of the underlying transmission systems; and economic development related to manufacturing, construction, and post construction.

The Recipient will create a written report summarizing this analysis.

Task 8. Participate in Eastern Interconnection Topic A activities

Subtask 8.A The Recipient will participate in the Eastern Interconnection Topic A Stakeholder Steering Committee.

Subtask 8.B The Recipient's in-house transmission planner will provide another source of coordination between the two Eastern Interconnection awards. Such coordination may include review, analysis, and interpretation of the Eastern Interconnection Topic A Recipient's modeling and planning efforts and communication of this to EISPC and the Recipient; as well as relay of this project's input to the Eastern Interconnection Topic A Recipient.

Subtask 8.C The Recipient will coordinate with the Eastern Interconnection Topic A Recipient and relevant stakeholders including coordination of deliverable schedules, outreach and communication, and efforts to achieve common messaging and common delivery of messages.

D. Deliverables

The periodic, topical, and final reports will be submitted in accordance with the attached "Federal Assistance Reporting Checklist" and the instructions accompanying the checklist.

In addition to the deliverables identified in the Federal Assistance Reporting Checklist, the Recipient will submit the following reports to DOE within 30 calendar days of the completion of the respective Task:

Task 1.

- Job descriptions of key staff
- Revised, detailed Project Management Plan
- Written process for handling confidential information between the Eastern Interconnection Topic A and Topic B Recipients
- Written process and protocol for reaching consensus and making decisions

Task 2.

- Meeting materials – Meeting materials include items prepared for the meeting including agendas and presentations as well as materials generated as a result of the meeting including participant lists, minutes, formal decisions, etc.
- Initial set of recommendations, positions, concerns, inputs, etc., for "Reference Case" and future scenarios

Task 3.

- Consensus feedback on the Eastern Interconnection Topic A Roll-up Integration Case results

Task 4.

- Written report detailing the Energy Zone study
- Written reports for each additional study

Task 5.

- Whitepapers

Task 6.

- Meeting materials – Meeting materials include items prepared for the meeting including agendas and presentations as well as materials generated as a result of the meeting including participant lists, minutes, formal decisions, etc.
- Consensus positions on alternative futures for macroeconomic analysis

Task 7.

- Meeting materials – Meeting materials include items prepared for the meeting including agendas and presentations as well as materials generated as a result of the meeting including participant lists, minutes, formal decisions, etc.
- Consensus positions on transmission build-out scenarios
- Consensus feedback on other Eastern Interconnection Topic A efforts
- Written report summarizing the analysis

Task 8.

- Meeting preparation and materials related to participation in Eastern Interconnection Topic A Stakeholder Steering Committee meetings and other activities – Meeting materials for this task include materials prepared to ready the Recipient for participation in Eastern Interconnection Topic A meetings and activities, as well as materials generated by the Recipient as a result of the participation in Eastern Interconnection Topic A meeting and activities.
- Materials developed in preparation for or resulting from communication and outreach with Eastern Interconnection Topic A Recipient and relevant stakeholders
- Coordination document developed in concert with Eastern Interconnection Topic A Recipient identifying coordination points throughout the projects and coordination of deliverables involving each recipient.

E. BRIEFINGS/TECHNICAL PRESENTATIONS

The Recipient shall provide and present a technical paper(s) at the DOE Annual Review Meeting to be held at either the NETL facility located in Pittsburgh, PA or Morgantown, WV; or other location specified by the DOE Project Officer.

The Recipient shall provide and present a technical paper(s) at the DOE Peer Review Meeting to be held at either the NETL facility located in Pittsburgh, PA or Morgantown, WV; or other location specified by the DOE Project Officer.

Appendix 3: "Soft Constraint Methodology"

I. Overview

To identify which transfer limits to expand and the magnitude of the transfer limit expansion for each regional interface, a methodology was developed by the EIPC and approved by the SSC called the "soft constraint methodology." The soft constraint methodology established an additional overflow pipe in the model for each transfer limit, for both flow directions, with an unlimited capacity and an economic charge that would be applied to flows across this set of overflow pipes. This additional pipe allowed the NEEM model to exceed the SSI model's transfer limits when the energy price in two neighboring regions exceeded an economic value, called the overload charge.

The overload charge is intended to represent the marginal value of increasing the transfer limits between NEEM regions and is not intended to be a proxy for the cost of expanding the transmission system. In order for the model to indicate transfer limit expansion, the value of the overload charge needed to be set at a value less than the difference in energy prices across two neighboring NEEM regions, also known as the shadow price. The SSC agreed to set the overload charge values at 75% (OL75) and 25% (OL25) of the shadow price for each transfer limit for the purpose of identifying which transfer limits that may be undersized in an interconnection-wide, least-cost economic dispatch.

The shadow prices used in setting the overload charge values were based upon the base case run. Once the soft constraint sensitivities were run, analysis was performed on the results to determine the appropriate transfer limit levels against which the remaining sensitivities would be run. These hardened pipe limits were then used in the NEEM model to run the remaining sensitivities for that particular future. The hardening process is described in Appendix 3, Section 1.0, A. The stakeholders then determined which pipe size would be used to run the remaining sensitivities for a particular future: the original limits determined by the Planning Coordinators, the hardened limits using the 25% soft constraint run, or the hardened limits using the 75% soft constraint run. In summary, the soft constraint methodology involved the following steps:

1. Run the base case for the future with the Planning Coordinator-developed transfer limits.
2. Run the soft constraint sensitivities when specified by the SSC.
3. Perform the hardening methodology on the soft constraint runs.
4. Stakeholders choose the base limits or new, hardened limits for the remaining sensitivity runs in the future.
5. Run the remaining sensitivities with the chosen limits.

A. Transfer Limit Hardening Methodology

The MWG NEEM Regions/Transmission Sub-Team used three different methodologies for developing the hardened limits that would be used in each future. These hardened limits were then used in the remaining sensitivity runs for the future. The methodologies were designed to use the output from the soft constraint runs and determine, based on that output, the level of transfer limits that would be used. Three methodologies were developed and ultimately the SSC decided to use an average of all three methodologies. Overall, the transfer limit hardening methodologies resulted in transfer limit, or pipe, expansions that were approximately 3% to 21% of the maximum pipe expansion indicated by the soft constraint runs. The process was applied to all the pipes in the model and the resulting increases in transfer limits were used by the Planning Coordinators to determine what additional transmission would need to be built to accommodate those transfers and the high-level cost of that transmission.

The three proposed transfer limit hardening methodologies are based on the 2020, 2025, 2030 and 2035 data sets from the Future 1: Business As Usual soft constraint data output. The data set contains the following information for each interface in both directions, approximately 100 interfaces, for each load block:

- Base case flows over the baseline pipe.
- OL75 flows over the baseline pipe and flows over the overload pipe.
- OL25 flows over the baseline pipe and flows over the overload pipe.
- Base case shadow prices.
    - Marginal benefit of increasing the flow by 1 MW all else being equal.
- Overload charges for OL75 and OL25 cases.
    - $/MW charge applied to each flow over the overload pipe.
    - Overload charges set to 75% or 25% of the average annual shadow price adjusted for load block size during only the congested hours.
- OL75 and OL25 shadow prices.
    - Always less than or equal to the overload charge.

This data was processed using the master transfer limit hardening methodology spreadsheet developed largely by Oak Ridge National Laboratory. That data set provides the following information:

- Fixed transfer limit increases for all pipes for each transfer limit hardening methodology.
- Flow duration curves for both OL75 and OL25 sensitivities for each year and for the combined years.
- Pipe target capacity factor-capacity curves for both OL75 and OL25 sensitivities for each year and for combined years.
    - Curves show different pipe magnitudes for different target pipe capacity factors assuming the OL75 or OL25 flows do not change.
    - Combined years target capacity factor-capacity curve graphed.

- Average transfer limit capacity for each year and for each year and for the combined years for both the total flows and the overload flows.
  - MWh flows divided by time period hours.
- Average shadow prices for the combined years.
  - Calculated by summing the products of load block hours by load block shadow price and dividing by either total hours or congested hours.

The following describes each of the methodologies in detail with possible benefits and drawbacks of each methodology described.

B. <u>Ruthven/Hadley/Chattopadhyay (RHC) Methodology – Building to a Target Capacity Factor by Shadow Price</u>

The RHC methodology calculates an increased transfer limit based on the average pipe increase developed from target capacity factors determined according to shadow prices applied to both total flows and overload flows.

1. For the total flow increase portion, RHC takes the total flows over a pipe (flows over the baseline pipe and flows over the overload pipe) and develops a new pipe size according to a target pipe capacity factor.
   a. The target pipe capacity factor of a pipe is determined proportionally to its average total shadow price.
      i. The average total shadow price is calculated by taking the total marginal congestion (shadow price for each load block times load block hour summed) and dividing it by the total hours.
      ii. The average total shadow price is used as it is indicative of, all things being equal, the amount of value that could be accessed over the course of the time period if the pipe were increased by 1 MW.
   b. To determine the target pipe capacity factor, the total flow capacity factor-shadow price curve parameter (default value of 1) is divided by the average total shadow price (average total shadow prices less than the parameter have a target pipe capacity factor of 100%).
   c. The pipe is then resized such that it can achieve that target pipe capacity factor assuming the flow patterns do not change. The pipe increase is assumed to be zero if the resized pipe is less than the baseline pipe size.
2. For the overload flow increase portion, RHC takes the overload flows over a pipe and develops a new overload pipe according to a target overload pipe capacity factor.
   a. The target pipe capacity factor of a pipe is determined proportionally to its average total shadow price.
      i. The average congested shadow price is calculated by taking the total marginal congestion (shadow price for each load block times load block hour summed) and dividing it by the congested hours.
      ii. The average congested shadow price is higher than the average total shadow price as it is calculated using a smaller number of hours. Some participants

believe it is more appropriate to only consider the congested hours when resizing the overload pipe. CRA uses the average congested hour shadow price when calculating overload charges.

b. To determine the target overload pipe capacity factor, the overload flow capacity factor-shadow price curve parameter (default value of 1) is divided by the average congested shadow price.
c. If the above methodology results in a target overload pipe capacity factor greater than the maximum overload pipe capacity factor parameter (default value of 33%), then the maximum overload pipe capacity factor is used.
    i. Allowing the overload pipe capacity factor to go above a certain value because of low or no shadow prices would cause unnecessary downstream congestion. CRA assigned pipes with no congestion a $0 overload charge in order to prevent the soft constraint methodology from moving congestion "one gate down;" i.e., when one congested pipe was expanded, all the congested energy that was not quickly absorbed would move to the next pipe down that had previously been uncongested. Assigning a maximum capacity factor value alleviates this concern to a certain extent.
d. The overload pipe is then resized such that it can achieve that target overload pipe capacity factor assuming the overload flow patterns do not change.

3. The total flow increase and the overload flow increase are then averaged to give a total pipe increase.
    a. Total flows are used to determine a new pipe size as total flows give information on where the pipe would like to expand. Particularly for pipes with a lot of congestion, overload pipes are likely to be used more than is shown in the overload flows as new, resized pipes would not have an overload charge associated with their use. Only looking at the overload flows would likely lead to pipes being too small.
    b. Overload flows are used to determine a new pipe size as they give specific information on where the model would like to build generation and increase generation utilization. If only total flows were used, a pipe could be expanded significantly even if the model preferred to expand other interfaces more to access cheaper generation potential.

C. NGO Methodology – Building to a Target Flow Duration Threshold

The NGOs recommended a solely flow-based methodology that calculates a new path size based on the flow duration curve that results from the sensitivity run(s). The methodology selected a new pipe size based on the flow needed for all except the last X% of hours of the period. The value, X%, is the cutoff, or threshold, value and can be 5%, 10%, 20%, or even higher, meaning that modelers build out to meet the flow needs for 95%, 90% or 80% of the time, respectively. The NGOs suggested a default value for X% to be 20% for OL25 flows, and 10% for OL75 flows. If the flows at the cutoff point were less than the current path limit, there was no path size expansion. The NGO methodology is intuitively simple, avoiding unnecessary complications that might provide little value to an undertaking of this size. By determining increases from flow patterns, the methodology implicitly takes into account economic information, as the flows are a result of the economic choices made by the model. Furthermore, the NGO methodology avoids the complication of determining an appropriate pipe capacity factor as pipe capacity factors are an output, not an input of the model.

The mechanics of the method are as follows:

1. For each of the 101 paths, the base flow (MW) and overload flow (MW) values were combined (by year, and by load block), for each of the applicable sensitivity runs, OL25 and OL75, to develop a total flow parameter for each run.
2. The total flow duration curve was created for each path representing all four years of data; 2020, 2025, 2030, and 2035; by combining total flow data from the sensitivity runs and sorting on the flow metric, largest to smallest value (y-axis value). Prior to sorting, the "duration" or hourly weight metric for each of these flows was retained to subsequently construct the x-axis duration value.
3. A threshold or x-axis cutoff value (hourly duration percentile – "parameter 1") was picked for each of the OL25 and OL75 sensitivity runs and the associated y-axis total flow was determined by moving vertically upward from the x-axis cutoff point to the flow duration curve above.
4. If the associated total flow was lower than the current path limit, then no increase to the pipe size for the path was required.
5. If the associated total flow was higher than the current path limit, then this flow value represented the total MW capacity of the increased path/pipe size.
6. The results were screened for anomalous conditions. Changes to the new pipe size could be made by either choosing a different cutoff point, or directly specifying a pipe size based on other factors following discussion with the NEEM Regions/Transmission Sub-Team.

D. <u>Stakeholder Choices and Results</u>

Below is a list of the futures and sensitivities where the shadow prices were reduced and the limits were chosen by the SSC.

- Future 1: Business As Usual – Two soft constraint sensitivities were run, one with shadow prices set to 25% of their level in the base case (OL25) and one with shadow prices set to 75% of their level in the base case (OL75). These sensitivities ultimately were not used and the transfer limits were set at the original levels determined by the Planning Coordinators because there were no significant changes in the resource mix. Setting the pipe limits to the original levels set by the Planning Coordinators means that no additional transmission is needed between the regions over and above what was included as part of the SSI model.
- Future 2: National Carbon Constraint – National Implementation – Two soft constraint sensitivities were run with shadow prices set to 75% of their level in the base case

(OL75) and 25% of their level in the base case (OL25).[25] The hardened version of the OL75 result was used for the remaining sensitivities resulting in an additional 40 GW buildout of firm transmission interface capacity between regions.

- Future 3: National Carbon Constraint – Regional Implementation – One soft constraint sensitivity was run with shadow prices set to 75% of their level in the base case (OL75) to be comparable with Future 2. The hardened version of this result was used for the remaining sensitivities. As mentioned in Section 2.5.2.2 the pipes between super regions were not allowed to expand in this model, only pipes within the super regions were allowed to expand. This process resulted in an additional 5 GW buildout of transmission.
- Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid – No soft constraint sensitivities were run and the original transfer limits determined by the Planning Coordinators were used for the remaining sensitivities because transmission expansion was not expected due to the aggressive energy efficiency lowering load. No additional transmission buildout was specified.
- Future 5: National Renewable Portfolio Standard – National Implementation – Two soft constraint sensitivities were run with shadow prices set to 75% of their level in the base case (OL75) and 25% of their level in the base case (OL25) (see footnote 13). The hardened version of the OL25 result was used for the remaining sensitivities. This resulted in an additional 64 GW buildout of transmission.
- Future 6: National Renewable Portfolio Standard – Regional Implementation - One soft constraint sensitivity was run with shadow prices set to 25% of their level in the base case (OL25) to be comparable to Future 5. The hardened version of this result was used for the remaining sensitivities. As mentioned above the pipes between super regions were not allowed to expand in this model, only pipes within the super regions were allowed to expand. This process resulted in an additional 3 GW buildout of transmission.
- Future 7: Nuclear Resurgence – One soft constraint sensitivity was run with shadow prices set to 25% of their level in the base case (OL25). Stakeholders chose to use the base case limits for this future, resulting in no additional transmission buildout.
- Future 8: Combined Federal Climate and Energy Policy – Both the OL25 and OL75 soft constraint sensitivities were run and the stakeholders chose the OL75 run to set the hardened limits, resulting in an additional 37 GW buildout of transmission.

II. High Level Transmission Cost Estimation Process for Task 5

[25] The SSC elected to run Futures 2 and 3 with the OL75 and Futures 5 and 6 with OL25 to observe the results and the effects on transmission expansion and high level cost estimates for two significant buildouts from two different policy drivers. Consistent soft constraint overload between Futures 2 and 3 and between Futures 5 and 6 was considered important when comparing the results of implementing a policy nationally versus regionally.

To support the SSC in assessing the results of the macroeconomic analysis and reaching consensus on the three future scenarios of interest, the EIPC developed an approach which employs generic, high-level transmission expansion cost estimates for use in comparisons among the macroeconomic scenarios. Because generic cost estimates are needed to develop and select scenarios of interest prior to specific modeling and detailed power flow analysis to be performed in Phase 2 of the project, they were intended only for use by the SSC in quantifying levels of transmission impacts among the many uncertain future expansion scenarios being considered relative to each other.

The approach applied in developing the high-level cost estimates was to utilize generic transmission line building blocks in a consistent manner by each of the Planning Coordinators to approximate the SSC requested increases in transfer capability between regions represented in the macroeconomic scenarios. EIPC also compiled a cost matrix of planning level, "cost per mile" estimates for common high voltage alternating current (HVAC) voltage levels among the Planning Coordinators. It was determined that the NEEM regions represented enough geographic diversity to warrant differences in regional costs. Therefore, 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.

These generic building blocks and cost estimates do not represent likely project solutions and were not intended to reflect specific facility costs. The absolute dollar values of these generic estimates were intended only to assist the SSC in selecting scenarios of interest, and are not applicable for other purposes or in any way indicative of actual transmission expansion costs, which must be developed through detailed local and regional assessments of specific expansion requirements. Examples of costs not considered include substation costs, upgrades to existing transmission systems, financing costs, specific right of way (ROW) routing requirements, etc.

As part of the process the following approach/assumptions were utilized:

1) Existing system capacity between NEEM regions was fully utilized and could not be relied upon; therefore, only new transmission enhancements were utilized to obtain the requested increase in transfer capability.
2) To represent the increases in transmission capacity between NEEM regions, EIPC utilized green field, generic transmission line building blocks.
3) To represent contingency capability, the approach included redundant circuits; e.g., for a 1,000 MW increase, a minimum of two 1,000 MW circuits were used with the second circuit accounting as a reinforcement to support the contingency loss of the first.
4) Planning Coordinators determined the termination points for the transmission line building blocks based upon knowledge of their local system(s).
5) No power flow analyses were performed.
6) Local impacts to the sending and receiving ends of the proposed circuits were not specifically addressed.

7) The integration of remote resources and large blocks of resource additions were considered as needed on a case-by-case basis.
8) In some limited locations, high voltage direct current (HVDC) solutions were considered in the high-level analyses.

In the development of the high-level transmission analysis solutions, coordination between the Planning Coordinators resulted in the identification of building blocks that approximated the SSC requested increase in transfer capability. In some cases where a substantially large increase in transfer capability was requested, the Planning Coordinators included additional transmission infrastructure to account for internal considerations of their respective regions.

The results of applying this procedure to each of the futures selected by the SSC in Task 5 are shown at “Results for Task 5 Production Cost Modeling” on the EIPC Modeling Results page of the EIPC Web site, found at: http://eipconline.com/Modeling_Results.html. The table below provides a summary of the estimated maximum and minimum cost developed for each future.

Table 9:High-Level Transmission Cost Estimates for each Future (Total Eastern Interconnection)

Future	Low	High
Future 2 OL 75 Total Cost:	$34,122,876,200	$48,799,582,300
Future 3 OL 75 Total Cost:	$1,730,666,200	$2,674,747,300
Future 5 OL 75 Total Cost:	$39,191,496,200	$58,332,337,300
Future 6 OL 25 Total Cost:	$2,069,929,200	$3,114,593,550
Future 8 OL 75 Total Cost:	$36,684,818,200	$51,054,582,550

III. Installed Capacity (GW) in 2030 for the Eastern Interconnection by Capacity Type for each Future

		Installed Capacity in 2030														
		F1S3	F1S4	F1S5	F1S6	F1S7	F1S8	F1S9	F1S10	F1S11	F1S12	F1S13	F1S14	F1S15	F1S16	F1S17
	Total	Base	High	Low	High	XHigh	XLow	HiEE	High	Low	Delay	LoEE	5YrDly	NoPTC	S15+	Final
	2010	Case	Load	Load	Gas	Gas	Rnw$	&RPS	PHEV	Rnw$	EPA	&RPS	EPA	NoRPS	HiLoad	Base
Coal	272	199	204	181	266	267	202	193	198	202	213	205	203	201	205	199
Nuclear	100	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
CC	133	202	305	147	158	158	186	170	214	190	190	229	200	210	318	202
CT	120	132	165	112	121	119	137	122	141	136	134	161	132	129	160	132
Steam Oil/Gas	75	36	47	9	23	22	38	19	38	37	31	43	34	34	47	36
Hydro	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
On-Shore Wind	19	68	79	55	92	93	120	72	69	108	66	54	68	38	38	68
Off-Shore Wind	0	2	2	2	2	2	4	2	2	4	2	2	2	2	2	2
Other Renewable	4	14	15	13	14	14	13	18	14	13	14	11	14	9	9	14
New HQ/Maritimes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	984	685	841	842	867	762	842	857	817	871	819	790	946	818
DR	33	71	85	58	71	71	71	109	73	71	71	32	71	71	85	71
Total w/DR	816	890	1,069	743	912	913	937	871	916	927	887	904	890	861	1031	889

Future 1: Business as Usual

		Installed Capacity in 2030													
		F1S3	F2B	F2S1	F2S2	F2S3	F2S4	F2S5	F2S6	F2S7	F2S8	F2S9	F2S10	F2S11	F2S12
	Total	BAU	Fed	75%	25%	50%	High	Low	ExHi	Low	Flat	Low	ExLo	Hard	High
	2010	Base	CO2	Soft	Soft	Frict	Load	Load	Gas	Gas	CO2	CO2	Rnw$	Limit	Intm
Coal	272	199	29	30	30	30	69	16	83	22	12	34	33	31	28
Nuclear	100	105	133	130	129	132	136	127	135	105	127	114	134	131	130
CC	133	202	246	230	224	226	306	166	170	265	249	240	213	226	225
CT	120	132	106	115	116	112	128	100	113	120	114	119	113	112	112
Steam Oil/Gas	75	36	22	27	28	29	35	9	21	27	28	28	29	29	29
Hydro	45	45	50	51	52	51	52	47	51	49	51	51	52	51	50
On-Shore Wind	19	68	282	313	315	320	385	232	348	243	312	279	357	317	349
Off-Shore Wind	0	2	2	2	2	2	2	2	2	2	2	2	3	2	2
Other Renewable	4	14	13	13	14	13	14	12	21	13	13	13	12	13	13
New HQ/Maritimes	0	0	0	0	3	3	3	3	3	3	3	3	3	3	3
Other	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	901	927	930	934	1,147	731	965	866	928	898	967	932	959
DR	33	71	71	71	71	71	85	58	71	71	71	71	71	71	71
Total w/DR	816	890	971	998	1,000	1,005	1,232	789	1,035	937	998	969	1,037	1,003	1,029

Future 2: National Carbon Constraint – National Implementation

		Installed Capacity in 2030													
		F1S3	F3B	F3S1	F3S3	F3S4	F3S5	F3S6	F3S7	F3S8	F3S9	F3S10	F3S11	F3S12	F3S13
	Total	BAU	Reg	75%	High	Low	ExHi	Low	Flat	Low	Hi $	HiCN	ExLo	Hard	High
	2010	Base	CO2	Soft	Load	Load	Gas	Gas	CO2	CO2	Nuke	Impt	Rnw$	Limit	Intm
Coal	272	199	40	35	66	18	82	24	12	33	39	38	34	39	33
Nuclear	100	105	134	134	137	132	134	105	133	112	105	134	128	134	133
CC	133	202	256	256	335	185	190	287	279	267	269	253	229	252	247
CT	120	132	104	105	128	84	104	118	108	115	116	105	107	105	106
Steam Oil/Gas	75	36	18	18	30	11	17	19	18	24	18	18	25	18	20
Hydro	45	45	52	52	52	49	53	50	52	51	52	51	53	52	51
On-Shore Wind	19	68	199	195	233	156	213	151	185	170	198	193	215	197	254
Off-Shore Wind	0	2	2	2	2	2	10	2	2	2	2	2	59	2	2
Other Renewable	4	14	13	13	14	12	33	13	13	13	13	13	26	13	13
New HQ/Maritimes	0	0	0	3	5	3	5	3	5	3	5	4	4	5	4
Other	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	833	829	1,019	668	857	789	821	807	833	829	897	833	879
DR	33	71	71	71	85	58	71	71	71	71	71	71	71	71	71
Total w/DR	816	890	904	900	1,105	726	927	860	892	878	904	900	968	903	950

Future 3: National Carbon Constraint – Regional Implementation

		Installed Capacity in 2030				
		F1S3	F4B	F4S1	F4S2	F4S3
	Total	BAU	Aggr	High	HiEV	XtrHi
	2010	Base	EE/DR	PHEV	OnPk	EE/DR
Coal	272	199	172	174	174	143
Nuclear	100	105	105	105	105	105
CC	133	202	138	139	142	94
CT	120	132	69	65	75	38
Steam Oil/Gas	75	36	3	3	3	1
Hydro	45	45	45	45	45	45
On-Shore Wind	19	68	54	56	56	48
Off-Shore Wind	0	2	2	2	2	2
Other Renewable	4	14	12	13	13	11
New HQ/Maritimes	0	0	0	0	0	0
Other	17	17	17	17	17	17
Total w/o DR	783	819	617	617	631	504
DR	33	71	152	153	158	186
Total w/DR	816	890	769	771	789	690

Future 4: Aggressive Energy Efficiency/Demand Response/Distributed Generation/Smart Grid

		Installed Capacity in 2030										
		F1S3	F5B	F5S1	F5S2	F5S3	F5S4	F5S5	F5S7	F5S8	F5S9	F5S10
	Total	BAU	Nat	75%	25%	High	High	Fed	Incr	50%	OffSh	Hard
	2010	Base	RPS	Soft	Soft	Load	Gas	CES	PHEV	Hurd	Wind	Limit
Coal	272	199	177	175	174	192	224	103	180	181	179	179
Nuclear	100	105	105	105	105	105	105	116	105	105	105	105
CC	133	202	167	167	167	235	153	215	170	161	166	166
CT	120	132	136	136	143	185	125	157	151	142	139	140
Steam Oil/Gas	75	36	38	39	39	47	22	43	40	39	37	38
Hydro	45	45	52	51	51	53	51	51	51	51	51	51
On-Shore Wind	19	68	236	220	216	284	216	163	224	216	197	217
Off-Shore Wind	0	2	2	2	2	2	2	2	2	2	20	2
Other Renewable	4	14	13	13	13	15	13	13	14	13	13	13
New HQ/Maritimes	0	0	0	6	6	6	6	3	6	6	6	6
Other	17	17	17	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	942	931	933	1,139	933	884	959	934	930	933
DR	33	71	71	71	71	85	71	71	76	71	71	71
Total w/DR	816	890	1,013	1,002	1,004	1,224	1,004	955	1,035	1,004	1,000	1,003

Future 5: National Renewable Portfolio Standard – National Implementation

		Installed Capacity in 2030									
		F1S3	F6B	F6S1	F6S2	F6S3	F6S4	F6S6	F6S7	F6S9	F6S10
	Total	BAU	Reg	25%	High	High	Fed	HiCN	Incr	OffSh	Hard
	2010	Base	RPS	Soft	Load	Gas	CES	Impt	PHEV	Wind	Limit
Coal	272	199	178	176	198	221	81	178	178	178	178
Nuclear	100	105	105	105	105	105	123	105	105	105	105
CC	133	202	157	159	209	147	246	156	161	157	157
CT	120	132	134	134	176	123	147	135	142	133	134
Steam Oil/Gas	75	36	38	38	48	22	42	37	39	37	38
Hydro	45	45	52	52	52	52	53	52	52	52	52
On-Shore Wind	19	68	160	159	187	160	138	158	164	154	159
Off-Shore Wind	0	2	39	39	51	39	2	39	39	51	38
Other Renewable	4	14	37	37	57	36	13	37	38	36	37
New HQ/Maritimes	0	0	0	1	1	1	1	1	1	0	1
Other	17	17	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	916	917	1,100	922	863	915	935	921	916
DR	33	71	71	71	85	71	71	71	76	71	71
Total w/DR	816	890	987	987	1,186	993	933	985	1,011	991	987

Future 6: National Renewable Portfolio Standard – Regional Implementation

		Installed Capacity in 2030					
		F1S3	F7B	F7S1	F7S2	F7S3	F7S4
	Total	BAU	Nuk	25%	High	CO2	SMR
	2010	Base	Res	Soft	Load	Price	Nuk
Coal	272	199	199	197	206	63	199
Nuclear	100	105	129	129	129	191	129
CC	133	202	174	172	280	265	174
CT	120	132	134	137	162	118	134
Steam Oil/Gas	75	36	34	35	47	30	34
Hydro	45	45	47	47	47	52	47
On-Shore Wind	19	68	68	68	77	116	68
Off-Shore Wind	0	2	2	2	2	2	2
Other Renewable	4	14	14	14	15	14	14
New HQ/Maritimes	0	0	0	0	1	0	0
Other	17	17	17	17	17	17	17
Total w/o DR	783	819	818	818	981	866	818
DR	33	71	71	71	85	71	71
Total w/DR	816	890	889	889	1,067	936	889

Future 7: Nuclear Resurgence

		Installed Capacity in 2030								
		F1S3	F8B	F8S1	F8S2	F8S3	F8S4	F8S5	F8S6	F8S7
	Total	BAU	CO2+	75%	25%	Low	Hi	75%w	75%w	Flat
	2010	Base	RPS	Soft	Soft	Rnw$	RPS	FltCO2	FltCO2	CO2
Coal	272	199	17	17	18	18	18	10	10	10
Nuclear	100	105	137	135	133	139	136	134	134	134
CC	133	202	210	199	186	181	190	215	213	208
CT	120	132	61	64	71	75	69	56	59	66
Steam Oil/Gas	75	36	9	4	4	4	4	5	5	4
Hydro	45	45	49	49	52	51	50	49	49	50
On-Shore Wind	19	68	245	263	287	294	303	259	259	261
Off-Shore Wind	0	2	2	2	2	3	2	2	2	2
Other Renewable	4	14	12	12	13	12	12	12	12	12
New HQ/Maritimes	0	0	0	0	3	5	5	0	0	5
Other	17	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	759	762	786	799	805	759	759	770
DR	33	71	152	152	152	152	152	152	152	152
Total w/DR	816	890	912	915	938	951	958	912	912	923

Future 8: Combined Federal Climate and Energy Policy

Appendix 4: Transfer Limit Hardening Methodology Descriptions

The 3 transfer limit hardening methodologies are based on the 2020, 2025, 2030 and 2035 energy transfer data sets for each soft constraint run. The data sets contain the following information for each interface (in both directions; ~100 interfaces) for each load block:

- Base-case flows over the baseline pipe
- OL75 flows over the baseline pipe and flows over the overload pipe
- OL25 flows over the baseline pipe and flows over the overload pipe
- Base-case shadow prices (marginal benefit of increasing the flow by 1 MW all else being equal)
- Overload charges for OL75 and OL25 cases ($/MW charge applied to each flows over the overload pipe; overload charges set to 75% or 25% of the average annual shadow price adjusted for load block size during only the congested hours)
- OL75 and OL25 shadow prices (always less than or equal to the overload charge)

This data is processed using the master transfer limit hardening methodology spreadsheet developed largely by Stan Hadley. That data sets output the following information:

- Fixed transfer limit increases for all pipes for each transfer limit hardening methodology
- Flow duration curves for both OL75 and OL25 sensitivities for each year and for the combined years
- Pipe target capacity factor-capacity curves for both OL75 and OL25 sensitivities for each year and for combined years (curves show different pipe magnitudes for different target pipe capacity factors assuming the OL75 or OL25 flows do not change; combined years target capacity factor-capacity curve graphed)
- Average transfer limit capacity for each year and for each year and for the combined years for both the total flows and the overload flows (MWh flows divided by time period hours)
- Average shadow prices for the combined years (calculated by summing the products of load block hours by load block shadow price and dividing by either total hours or congested hours)

Each of the three methodologies has a series of parameters that can be easily adjusted in the master spreadsheet with the results for all methodologies for both the OL75 and the OL25 sensitivities being displayed on the All Lines tab.

The following will describe each of the methodologies in detail with possible benefits and negatives of each methodology described.

Ultimately, the SSC agreed to use the average of the three methodologies in order to determine the hardened transfer limit increases.

Ruthven/Hadley/Chattopadhyay Methodology – Building to a Target Capacity Factor by Shadow Price

The RHC methodology calculates an increased transfer limit based on the average pipe increase developed from target capacity factors determined according to shadow prices applied to both total flows and overload flows.

1. For the total flow increase portion, RHC takes the total flows over a pipe (flows over the baseline pipe + flows over the overload pipe) and develops a new pipe size according to a target pipe capacity factor.
    a. The target pipe capacity factor of a pipe is determined proportionally to its average total shadow price.
        i. The average total shadow price is calculated by taking the total marginal congestion (shadow price for each load block times load block hour summed) and dividing it by the total hours.
        ii. The average total shadow price is used as it is indicative of, all things being equal, the amount of value that could be accessed over the course of the time period if the pipe were increased by one MW.
    b. To determine the target pipe CF, the total flow CF-shadow price curve is developed according to the following formula:
        i. ((MBTSP*TFP)-TSP)/(MBTSP*TFP)
        ii. Where:
            1. MBTSP = the maximum average total shadow price of any transfer limit from the base case
            2. TFP = total flow shadow price parameter (default value of 75%)
            3. TSP = the average total shadow price for the given pipe
        iii. The target CF is subject to a max an min CF (default values respectively 85% and 40%).
    c. The pipe is then resized such that it can achieve that target pipe CF assuming the flow patterns do not change. The pipe increase is assumed to be 0 if the resized pipe is less than the baseline pipe size
2. For the overload flow increase portion, RHC takes the overload flows over a pipe and develops a new overload pipe according to a target overload pipe capacity factor
    a. The target pipe capacity factor of a pipe is determined proportionally to its average total shadow price.
        i. The average congested shadow price is calculated by taking the total marginal congestion (shadow price for each load block times load block hour summed) and dividing it by the congested hours.
        ii. The average congested shadow price is higher than the average total shadow price as it is calculated using a smaller number of hours. Some participants believe it is more appropriate to only consider the congested hours when resizing the overload pipe. CRA uses the average congested hour shadow price when calculating Overload Charges

   b. To determine the target overload pipe CF, the overload flow CF-shadow price curve is developed according to the following formula:
      i. ((MBCSP*OFP)-CSP)/(MBCSP*OFP)
      ii. Where:
         1. MBCSP = the maximum average congested shadow price of any transfer limit from the base case
         2. OFP = overload flow shadow price parameter (default value of 75%)
         3. CSP = the average congested shadow price for the given pipe
      iii. The target CF is subject to a max and min CF (default values respectively 35% and 15%).
   c. The overload pipe is then resized such that it can achieve that target overload pipe CF assuming the overload flow patterns do not change.
3. The total flow increase and the overload flow increase are then averaged to give a total pipe increase
   a. Total flows are used to determine a new pipe size as total flows give information on where the pipe would like to expand. Particularly for pipe with a lot of congestion, overload pipes are likely to be used more than is shown in the overload flows as new, resized pipes would not have an overload charge associated with their use. Only looking at the overload flows would likely lead to pipes being too small.
   b. Overload flows are used to determine a new pipe size as they give specific information on where the model would like to build generation and increase generation utilization. If only total flows were used, a pipe could be expanded significantly even if the model preferred to expand other interfaces more to access cheaper generation potential.

NGO Methodology – Building to a Target Flow Duration Threshold

The NGO methodologyis a flow based methodology that calculates a new path size based on the flow duration curve that results from the sensitivity run(s). It selects a new pipe size based on the flow needed for all *except* the last X% of hours of the period. X (cutoff, or threshold value) can be, e.g., 5%, 10%, 20%, or even higher (meaning that you build-out to meet the flow needs for 95%, 90% or 80% of the time, respectively). The default value is 20%. If the flows at the cutoff point are less than the current path limit, there is no path size expansion. By determining increases off of flow patterns, the methodology implicitly takes into account economic information as the flows are a result of the economic choices made by the model. Furthermore, the NGO methodology avoids the complication of determining an appropriate pipe capacity factor as pipe capacity factors are an output, not an input of the model.

1. The mechanics of the method are as follows:
   a. For each of the 101 paths, combine the base flow (MW) and overload flow (MW) values (by year, and by load block), for each of the applicable sensitivity runs - OL25 and OL75 – to develop a “total flow” parameter for each run.

b. Create the total flow duration curve for each path representing all four years of data - 2020, 2025, 2030 and 2035 – by combining total flow data from the sensitivity runs and sorting on the flow metric, largest to smallest value (y-axis value). Prior to sorting, retain the “duration” or hourly weight metric for each of these flows to subsequently construct the x-axis duration value.
c. Pick a threshold or x-axis cutoff value (hourly duration percentile – “parameter 1”) for each of the OL25 and OL75 sensitivity cases and determine the associated y-axis total flow by moving vertically upward from the x-axis cutoff point to the flow duration curve above.
d. If the associated total flow is lower than the current path limit, then no increase to the pipe size for the path is required.
e. If the associated total flow is higher than the current path limit, then this flow value represents the total MW capacity of the increased path (pipe) size.
f. Screen the results for anomalous conditions. Changes to the new pipe size can be made by either choosing a different cutoff point, or directly specifying a pipe size based on other factors following discussion with the Transmission sub-team.

Johnson Methodology – Building to a Target Capacity Factor based on Average Energy Transfers

The methodology is an energy transfer based methodology that filters pipes according to average annual energy utilization of the existing baseline pipe and then resizes pipes according to a desired capacity factor. If an existing baseline pipe is being used greater than 90% of the time (taking into account both baseline and overload flows, a pipe can be used more than 100% of the time), then it builds a new path size to a 75% capacity factor. I.e., it recognizes that the existing pipe is nearing its annual limit, and bumps it up accordingly – and proportionately – to the new flow from the sensitivity run.

The methodology relies on the idea that the “energy transfers” from the OL25 and/or OL75 transmission sensitivities implicitly encapsulate the marginal cost of production and capital cost differentials between NEEM regions.

The mechanics of the method are as follows:

1. The average annual energy transfer (MW) for a pipe is calculated (total flows over a pipe divided by total hours
2. The average annual capacity utilization is calculated (average annual energy transfer MW divided by baseline pipe capacity MW)
3. If the average annual capacity utilization is greater than the capacity utilization threshold (parameter 1 – default value of 90%) then the pipe is considered for an increase
4. Pipes considered for increase are upgraded to a target capacity factor (parameter 2 – default value of 75%)

   a. Average annual energy transfer is divided by the target capacity factor to yield the new pipe size
   b. If the new pipe size is smaller than the baseline pipe, then the pipe is not expanded

Methodology Demonstration Examples

RHC Methodology Steps Taken from F2 OL75 NE to MISO_W Transfer Limit:

1. Target Capacity factor for total flow calculated = 60%
   a. Average shadow price calculated for all hours = $12.28
      i. $430,437.62 marginal congestion/35040 hours =$12.28
   b. MBTSP = $41.04
   c. Calculate capacity factor using TFP = 75%
      i. ((41.04*.75)-12.28)/(41.04*.75) = 60%
2. Target Capacity factor for overload flow calculated = 35%
   a. Average shadow price calculated for all congested hours = $19.72
      i. $430,437.62 marginal congestion/21826 congested hours = $19.72
   b. MBCSP = $48.19
   c. Calculate capacity factor using OFP = 75%
      i. ((48.19*.75)-19.72)/(48.19*.75) = 45%>Max overload CF of 35% therefore overload flow CF =35%
3. Calculate any increase in pipe capacity based on total flow target capacity factor-capacity curve = 2254 MW
   a. Total flows over line size X (assuming flow pattern remains identical)/potential total flows over line size X = line CF
   b. Total flow target cf-capacity curve shows at 60% CF, transfer limit should be 3854 MW
   c. Actual baseline capacity is 1600 MW so an increase of 2254 MW
4. Calculate any increase in pipe capacity based on overload flow target capacity factor-capacity curve = 3640 MW
   a. Overload flows over overload line size X (assuming flow pattern remains identical)/potential total flows over overload line size X = line CF
   b. Overload flow target cf-capacity curve shows at 35% CF, overload transfer limit should be 3640 MW
5. Calculate average of pipe increase due to total flows and average of pipe increase due to overload flows = 2947 MW

NGO Methodology Steps Taken from F2 OL 75 NE to MISO_W Transfer Limit:

1. Flow duration curve created using total flows for all hours of the combined years
2. Pipe size equal to a designated cutoff to upper end of flow duration curve
   a. Flow duration curve target parameter = 20%
   b. Flows at 20% target cutoff = 4278 MW
   c. Since pipe increase is greater than 1600 MW baseline capacity, pipe increased by 2678 MW

Johnson Methodology Steps Taken from F2 OL75 NE to MISO_W Transfer Limit:

1. Average total MW energy transfers calculated for combined years= 2581 MW
   a. Total energy transfers = 90428 GWh divided by Total Hours = 35040 times 1000 = 1665 MW
2. Capacity utilization threshold applied
   a. Average MW energy transfers divided by baseline capacity (1600 MW) = 161%
   b. 161%> threshold interface utilization parameter (default value of 90%)
   c. Since pipe passes threshold, pipe is considered for expansion
3. Pipe size increase calculated = 1841 MW
   a. Average MW energy transfers 2581 MW divided by average capacity factor for total line parameter (default value of 75%) = 3441 MW
   b. Since new pipe size is greater than baseline pipe (1600 MW), pipe increased by 1841 MW

Table 10: Methodology Results – Average of All TLH Methodologies for All Soft Constraint Runs

	F1S1 OL75	*F1S2* OL25	*F2S1* OL75	*F2S2* OL25	*F3S1* OL75	*F5S1* OL75	*F5S2* OL25	*F6S1* OL25	*F7S1* OL75	*F8S1* OL75	*F8S2* OL25	*F8S5* OL75	*F8S6* OL75
MISO_W_2_PJM_ROR	0	0	12,420	31,421	0	1,285	9,362	0	0	19,066	36,654	6,400	11,217
SPP_N_2_ENT	0	0	13,843	16,272	0	3,981	7,440	0	0	5,546	13,928	3,652	3,960
MISO_WUMS_2_MISO_MI	977	10,054	688	15,406	1,323	7	49	830	235	195	4,604	29	19
MISO_MI_2_MISO_IN	0	1,456	0	8,251	0	0	0	0	0	0	15	0	0
SPP_N_2_MISO_MO-IL	0	0	2,019	7,084	0	490	263	0	0	1,954	4,885	339	648
MISO_W_2_MISO_WUMS	0	0	38	5,698	0	437	2,127	0	0	118	257	145	160
NE_2_MISO_W	0	0	2,489	5,612	0	1,592	17,497	0	0	2,014	3,662	1,246	621
SPP_S_2_ENT	0	0	1,992	5,132	0	1,825	4,282	0	0	3,430	4,288	1,810	2,066
MISO_W_2_MISO_MO-IL	0	0	122	4,954	115	2,113	4,073	0	0	248	3,348	0	0
ENT_2_SOCO	0	0	1,900	4,497	0	0	431	0	0	0	2,466	0	0
MISO_MO-IL_2_MISO_IN	0	0	0	4,104	0	3,474	4,129	0	0	0	5,121	1,178	351
NE_2_SPP_N	555	2,911	160	3,355	0	583	10,998	1,201	1,055	54	1,033	87	126
IESO_2_MISO_MI	0	0	751	2,904	0	0	0	0	0	1,285	4,478	898	923
NYISO_A-F_2_NYISO_G-I	507	1,059	1,435	2,271	1,593	658	638	507	742	1,016	1,570	872	1,042
PJM_ROR_2_PJM_ROM	0	0	0	1,787	0	0	0	0	0	0	0	0	0
SPP_N_2_SPP_S	0	0	236	1,069	0	0	1,571	0	0	0	0	158	362
NEISO_2_NYISO_J-K	82	57	315	825	347	65	90	70	203	608	934	195	76
PJM_ROR_2_VACAR	0	0	0	460	0	0	865	0	0	0	1,699	63	87
IESO_2_NYISO_A-F	19	191	0	358	0	0	0	0	316	499	242	602	598
NYISO_G-I_2_NYISO_J-K	0	0	0	70	0	0	0	58	207	0	0	0	0
SPP_N_2_NE	0	0	0	64	2	0	0	0	0	0	0	0	0
NYISO_J-K_2_PJM_E	35	54	74	44	0	67	70	0	47	2	3	2	1
IESO_2_MISO_W	156	107	67	35	0	42	74	0	133	55	0	41	4
SPP_N_2_MISO_W	0	0	337	32	0	0	0	0	0	250	1,135	52	67
MAPP_CA_2_MISO_W	0	0	0	1	226	0	0	18	0	0	261	0	0
SPP_S_2_SPP_N	0	320	0	0	0	0	0	383	0	0	77	0	0
MISO_MI_2_MISO_WUMS	0	0	0	0	0	102	8	0	20	140	76	424	372
MISO_IN_2_MISO_MI	0	0	768	0	21	0	81	0	0	490	14	0	0
IESO_2_MAPP_CA	62	48	0	0	0	0	0	0	3	7	5	0	0
MISO_W_2_MAPP_CA	227	2,341	0	0	0	0	88	15	1,947	0	0	0	0
MAPP_US_2_MAPP_CA	0	0	0	0	0	0	65	0	0	0	0	0	0
MISO_IN_2_PJM_ROR	0	0	261	0	0	0	0	0	0	0	0	0	0
MISO_WUMS_2_MISO_W	892	3,101	0	0	103	0	0	0	0	0	0	0	0
NEISO_2_NYISO_G-I	62	157	0	0	0	0	0	0	27	0	0	0	0
NEISO_2_NYISO_A-F	0	19	0	0	0	0	0	0	0	0	0	0	0
PJM_ROM_2_NYISO_A-F	0	0	0	0	0	32	0	0	0	0	0	0	0
MISO_MO-IL_2_MISO_W	167	0	0	0	0	0	0	0	29	0	0	0	0
MISO_IN_2_MISO_MO-IL	0	0	0	0	533	0	0	0	0	0	0	0	0
Total TX Limit Increase	3,741	21,876	39,916	121,706	4,263	16,754	64,203	3,082	4,963	36,978	90,758	18,192	22,699

Appendix 5: Modeling Electricity Flows from Hydro Quebec and the Maritimes

Summary

As the MRN-NEEM model does not have NEEM regions for Quebec or the Maritimes, the MWG NEEM/TX Subteam, with assistance from the Canadian Subteam and other participants, propose an alternative method of modeling resources from these regions so that they are placed on a level playing field with resources in modeled NEEM regions. Existing flows (including expected flows due to developments in the Baseline Infrastructure) will be hard wired into the model based on historical and projected levels. New HQ and Maritimes resources will be modeled using pseudo-generators. New resources imported into neighboring NEEM regions will only be allowed to develop in cases in which NEEM region transfer limits are allowed to increase to ensure comparability. As for increased transfer limits between NEEM regions, increased transmission needed to access potential generation in HQ/Maritimes will be cost-estimated by the PAs. Detailed numbers are available in Table 25 of the MRN-NEEM Inputs document.

Existing Flows

- Existing Flows includes all flows resulting from transmission and generation in the Baseline Infrastructure
    - As the Baseline Infrastructure includes expanded transmission between Hydro Quebec-New England (Northern Pass Line) and the Maritimes-New England (Northeast Energy Link) flows from these lines are considered "existing"
- Flows between HQ-NE include flows over Phase I/II (1500 MW), Highgate (220 MW) and Northern Pass (1200 MW)
    - All flows over these lines will be treated using a 75% capacity factor (created by the lines delivering energy at full capacity for 18 hours a day and zero capacity for 6 hours a day) derived from historical flow values
        - 75% capacity factor based on historical and expected flows
    - 100% of the capacity (2920 MW) will be available to satisfy reserve margins as the lines will be delivering energy during peak hours
    - MRN-NEEM will treat the flows as fixed generation for New England
- Flows between Maritmes-NE include existing flows (~1000 MW) and flows resulting from upgrades in the NEL project (400 MW)
    - All flows over these lines will be treated using a 71% capacity factor (created through the development of a load curve for various types of generation technologies) derived from historical and expected flow values
        - 71% capacity factor based on historical and expected flows
    - 100% of the capacity (1400 MW) will be available to satisfy reserve margins as the lines will be delivering energy during peak hours
    - MRN-NEEM will treat the flows as fixed generation for New England

- Flows between HQ-NY include flows over Chateaugay (1500 MW)
    - o All flows over these lines will be treated using a 44% capacity factor (created by the lines delivering energy at 1000 MW capacity for 16 hours a day and zero capacity for 8 hours a day) derived from historical 2009-10 flow values
    - o 80% of the line capacity (1200 MW) will be available to satisfy reserve margins as the lines will be delivering at least this amount of energy during peak hours
    - o MRN-NEEM will treat the flows as fixed generation into New York
- Flows between HQ-OH (~3000 MW)
    - o All flows over these lines will be treated using a 9% capacity factor (created by the lines delivery energy at 400 MW capacity for 16 hours a day and zero capacity for 8 hours a day) derived from historical 2010 flow values
    - o 0% of the line capacity will be available to satisfy reserve margins as OH long-term planning does not rely on interconnections to meet reserve requirements
    - o MRN-NEEM will treat the flows as fixed generation into Ontario

New Development

- The overall goal is to allow the model to build additional potential HQ and Maritimes generation similarly to the manner in which the model builds new generation in other areas
- Exports from HQ and the Maritimes to New England and New York will be modeled using Pseudo-generators
    - o As in other NEEM regions, transmission necessary for the export of the power produced by the pseudo-generators will be cost-estimated by the PAs
- Pseudo-generators will be identical to regular generation for MRN-NEEM purposes
    - o E.g. MRN-NEEM will be able to select to build in New England an HQ-NE pseudo-generator representing HQ hydro capacity imports into New England
    - o As part of the Pseudo-generation characteristics, a $7/MWh charge will be included to account for hurdle rates/wheeling charges that would normally be present in flows between NEEM regions
        - ▪ The hurdle rate/wheeling charge is based on the hurdle rates and wheeling charges for exports from Ontario to other NEEM regions
- Treatment of Pseudo-generators will depend upon a Future's intended characteristics
    - o For a future base-run, the model will not be able to select pseudo-generators
        - ▪ The base-run represents a case in which no transmission is built beyond the Baseline Infrastructure, therefore, no new flows from HQ or Maritimes would be possible
    - o For a soft constraint sensitivity, the model will be able to select pseudo-generators and the pseudo-generators will have a proxy overload charge
        - ▪ This sensitivity represents a case in which transmission is built beyond the Baseline Infrastructure, therefore new flows from HQ or the Maritimes would be possible
        - ▪ The proxy overload charge will be set at either 75% or 25% (depending on whether it is an OL75 or OL25 sensitivity) the average shadow price on constraints between Ontario and other NEEM regions

        - There are no shadow prices between HQ/Maritimes and neighboring regions as HQ/Maritimes are not NEEM regions therefore Ontario is serving as a proxy
    - The model will economically select pseudo-generators up to their level of resource capacity given the capital costs, resource limits, hurdle rates/wheeling charges, and proxy overload charges of the pseudo-generating units
    - As for all overload charges the proxy overload charge is not representative of the cost of transmission expansion between HQ/Maritimes and neighboring regions. The cost of this transmission will be accounted for when the PAs create their high-level cost estimates of transmission expansion cases
  - After the soft constraint runs, the SSC will choose between using Baseline Infrastructure transmission or soft constraint transmission for the remaining sensitivities of the future
    - If the SSC chooses to use Baseline Infrastructure transmission for the remaining sensitivities, the model will not be able to select pseudo-generators
        - These would be cases in which no transmission is built beyond the Baseline Infrastructure, therefore, no new flows from HQ or Maritimes would be possible
    - If the SSC chooses to use the hardened soft constraint transmission for the remaining sensitivities:
        - The model will able to select pseudo-generators as this is a case in which transmission is "built" to accommodate those generators
        - The maximum capacity available from HQ/Maritimes pseudo-generators will be set equal to:
            - the maximum level utilized in the relevant soft constraint sensitivity

Pseudo-generation details

- Pseudo-generation units from HQ will consist of new Hydro
  - Pseudo-generators from HQ will be load following according to 2006 load shapes.
  - HQ Hydro will have a total Hydro resource limit of 5300 MW available for export
    - Resource limit is based on forecasted excess winter capacity (HQ peak period) available above baseline infrastructure flows. Excess summer capacity is forecasted at 21500 MW by 2035
    - HQ-NE, HQ-NY and HQ-OH will each have a limit of 2500 MW of the 5300 MW total
  - HQ Hydro capital cost characteristics come from AEO 2011
  - HQ hydro will have a capacity credit identical that applied for existing flows (i.e. 100% in New England, 80% in New York and 0% in Ontario)

- Pseudo-generation units from the Maritimes will consist of new Wind and new Hydro
    - Load patterns for wind pseudo-generators from the Maritimes will be based on wind load patterns in Maine adjusted to reflect a 35% capacity factor for Maritimes wind
        - Maritimes wind pseudo-generators will have a resource limit of 1500 MW based on the New England 2030 Power System Study estimate of what might be available from the Maritimes for export to New England.
        - Maritimes wind capital cost characteristics will be identical to wind capital cost characteristics in NEEM regions
        - Maritimes wind will have a 15% capacity credit (identical to wind within New England)
    - Hydro pseudo-generators from the Maritimes will be load following according to 2006 load shapes.
        - Maritimes hydro pseudo-generators will have a resource limit of 500 MW based on regional understandings of what is available for development and export with the Maritimes and Newfoundland and Labrador
        - Maritimes hydro capital cost characteristics come from AEO 2011
        - Maritimes hydro will have a 100% capacity credit (identical to hydro imports into New England)

Appendix 6: Acronym List

Acronym	Term
AEEI	Autonomous Energy Efficiency Improvement
AEO	Annual Energy Outlook
BAU	Business As Usual
CC	Combined Cycle
CCS	Carbon Capture and Storage
CRA	Charles River Associates
CT	Combustion Turbine
DG	Distributed Generation
DOE	Department Of Energy
DR	Demand Response
EE	Energy Efficiency
EI	Eastern Interconnection
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EPA	Environmental Protection Agency
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FOA	Funding Opportunity Announcement
GDP	Gross Domestic Product
IGCC	Integrated Gasification Combined Cycle
ISONE	Independent System Operator of New England
ITPA	Interconnection-level Transmission Planning and Analysis
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent System Operator
MMWG	NERC Multi-Regional Modeling Working Group
MRN	Multi-Region National
MWG	Modeling Working Group
NARUC	National Association of Regulatory Utility Commissions
NEEM	North American Electricity and Environment Model
NEEM/TX	NEEM Region / Transmission Sub-Team of the Modeling Work Group
NGCC	Natural Gas Combined Cycle
NETL	National Energy Technology Laboratory
NGO	Non-Governmental Organizations
NPV	Net Present Value
NRRI	National Regulatory Research Institute
NYISO	New York Independent System Operator
PJM	PJM Interconnection
PMP	Project Management Plan
PTC	Production Tax Credit

Acronym	Term
PV	Present Value *or* Photovoltaic
RHC	Ruthven/Hadley/Chattopadhyay methodology
RPS	Renewable Portfolio Standard
RUWG	Roll-Up Working Group
SIRRP	Southeast Inter-Regional Participation Process
SOPO	Statement Of Project Objectives
SPP	Southwest Power Pool
SPWG	Scenario Planning Working Group
SSC	Stakeholder Steering Committee
SSI	Stakeholder Specified Infrastructure
STF	Scenario Task Force
VER	Variable Energy Resource