APPENDIX F

TRANSMISSION PLANNING

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INTRODUCTION

This Appendix describes transmission planning needs and processes that affect Connecticut. The first section summarizes transmission planning processes in New England, including key planning initiatives, recent studies, and achievements since the 2012 IRP. The second section summarizes identified transmission needs and ongoing studies in Connecticut for system reliability, particularly in Southwest, Central, and Eastern Connecticut. Later sections discuss activities and ongoing challenges in regional transmission planning for remote renewables in New England, including a discussion of lessons learned from other Regional Transmission Organization (RTO) areas such as the Midwest ISO (MISO), Southwest Power Pool (SPP), California ISO (CAISO), and Electric Reliability Council of Texas (ERCOT).

TRANSMISSION PLANNING IN NEW ENGLAND

Transmission planning in New England involves a wide range of parties, including the system operator, transmission owners, policymakers, consumer advocates, and other regional stakeholders. Transmission planning also involves complex multi-stage processes for coordination, technical system studies, project design, and cost allocation. The specific planning process varies by type of project. Most projects are reliability projects conducted by transmission owners for reliability purposes. Other projects built by incumbent transmission owners or merchant developers include economic projects, which improve the economic efficiency of the grid, and public policy projects, which support policy goals such as renewable integration. The sections below describe each type.

ISO New England and Planning for Reliability

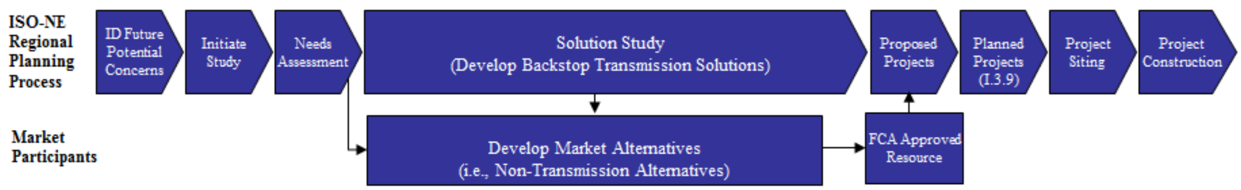
The ISO New England (ISO-NE), as the regional system operator under FERC jurisdiction, is responsible for ensuring reliability of the bulk power system, and for ensuring regional coordination and stakeholder involvement in the transmission planning process for reliability. All new transmission projects must receive ISO-NE technical approval, and must meet the rules and conditions of ISO-NE's FERC-approved Transmission, Markets, and Services Tariff.[1]

ISO-NE's annual Regional System Plan (RSP) is the culmination of the regional reliability planning process. The expertise of New England's transmission owners and input from other stakeholders are crucial in this process for identifying current and projected system issues, identifying candidate projects to resolve those issues, and determining the best solutions. The Regional System Plan is also developed in coordination with inter-regional planning initiatives and studies, including those of the ISO/RTO Council (IRC), the ISO New England/NYISO/PJM planning protocol, and the Eastern Interconnection Planning Collaborative (EIPC). ISO-NE's annual RSP report presents updated results of this ongoing planning process: namely, a set of planned reliability projects needed over a 10-year planning horizon in order to maintain NERC and NPCC reliability standards for the transmission system. The costs of the planned reliability projects are recovered through FERC-approved regional or utility-specific transmission rates administered by the ISO. These projects also generally go through a more streamlined state siting and permitting process compared to other types of transmission projects.

[1] *ISO New England Inc. Transmission, Markets, and Services Tariff.* Available at http://www.iso-ne.com/regulatory/tariff/index.html

Reliability projects are identified and studied through a multi-step process, as shown in Figure 1. Individual sub-area studies ("Needs Assessments") are performed to identify system needs over a ten-year horizon. When a system reliability problem is identified from a needs assessment, ISO-NE and the TOs develop one or more transmission system options and alternatives (*i.e.*, backstop transmission solutions) to address all of the transmission reliability needs and ensure that NERC and NPCC reliability standards are met. (In parallel, market participants can develop and propose non-transmission alternatives, as discussed separately below). The viable transmission system alternatives are further evaluated to determine feasibility of construction, environmental impacts, costs, longevity, and operational considerations. When the analysis of the alternatives is complete, the TOs recommend a proposed transmission project to ISO-NE and the Planning Advisory Committee (PAC). These studies, and the proposed transmission solutions, are documented in a solutions study, and in aggregate provide the basis to update ISO-NE's Regional System Plan.

Figure 1

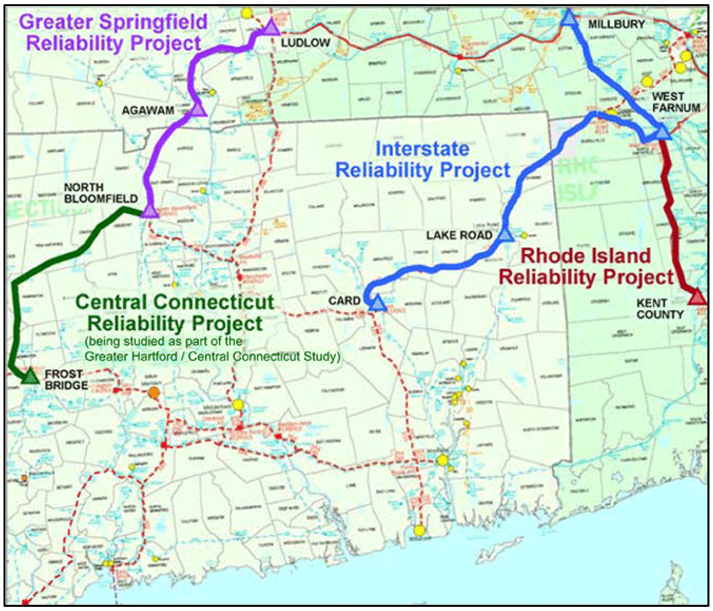


Since the 2012 IRP, the region has moved forward with two major reliability projects affecting Connecticut: the New England East-West Solution (NEEWS) and the Maine Power Reliability Program (MPRP). The four major components of NEEWS, shown in Figure 2, have moved forward in various stages of development:

- Rhode Island Reliability Project: The project was placed in-service in May 2013.
- Greater Springfield Reliability Project: The project was placed in-service in November 2013. Among other system reliability benefits, this project increased Connecticut's transmission import capability by approximately 100 MW.
- Interstate Reliability Project: Construction is underway, and expected to be complete by year-end 2015. Among other system reliability benefits, this project improves Connecticut's resource adequacy outlook by approximately 700 MW, by moving the Lake Road generating station electrically into Connecticut, and by strengthening transmission ties with Rhode Island and Southeastern Massachusetts.
- Central Connecticut Reliability Project: This project will be cancelled upon ISO-NE approval of the Greater Hartford–Central Connecticut (GHCC) Project.as the needs that

were originally addressed by this project are included by GHCC study, discussed in the next section of this Appendix.[2]

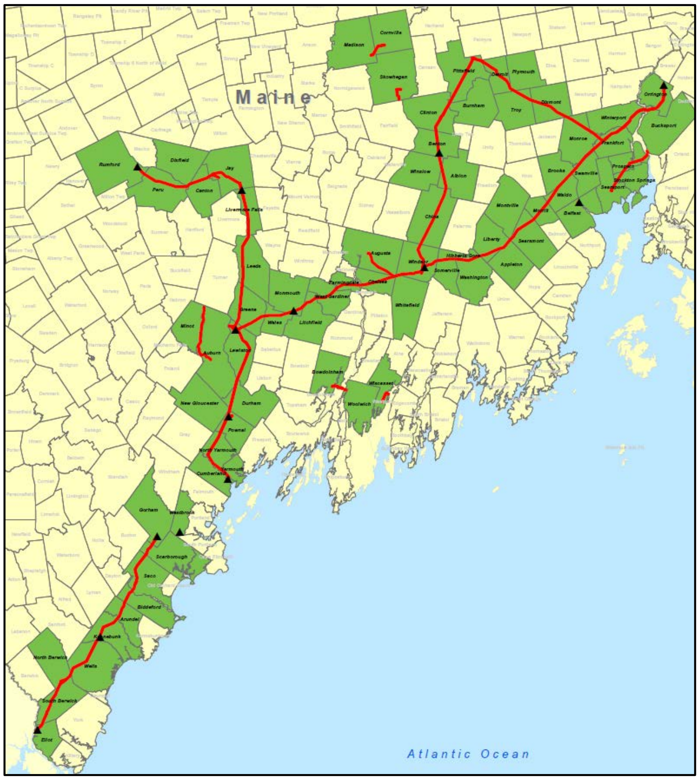
Figure 2
New England East-West Solution (NEEWS)[3]



The Maine Power Reliability Program (MPRP) is shown in Figure 3. MPRP is currently under construction, with expected completion in 2015. This project, in addition to mitigating NERC and NPCC reliability criteria violations in Maine, will provide modest transfer capability improvements across major interfaces in Maine. Transfer capability improvements to Maine interfaces are relevant for Connecticut because they partially address Maine system wind integration issues such as power export limitations from Maine to New Hampshire. Planned or other future new wind resources contracted in Maine to help meet Connecticut's Renewables Portfolio Standard are interconnected to electrically remote and weak portions of the New England transmission grid.[4] These Maine wind resources pose operational challenges due to issues with voltage and stability performance. Since these and other wind integration issues have yet to be fully resolved, ISO-NE is considering use of Elective Transmission Upgrades to strengthen electrically weak portions of the New England transmission system. Several regional studies in recent years have indicated that significant new transmission lines and upgrades will be needed to fully integrate new wind development in that area. This issue is discussed in more detail later in this Appendix.

2 ISO-NE Planning Advisory Committee Materials for October 22, 2014, available at http://www.iso-ne.com/static-assets/documents/2014/10/a3_october_2014_rsp_projct_list_presentation.pdf.
3 www.NEEWSprojects.com.
4 See also discussion in Section 1.3.4.3 of the ISO-NE 2014 Regional System Plan.

Figure 3
Maine Power Reliability Program (MPRP)[5]



Planning for Economic Projects

As part of the Regional System Plan process, ISO-NE also considers transmission projects that are designed to reduce bulk power system costs to load, so-called "market efficiency projects." Market efficiency projects are the specific subset of economically beneficial projects that ISO-NE selects as part of its transmission expansion plan. Other economically beneficial projects that do not meet ISO-NE's criteria for market efficiency projects may be self-funded through the Elective Transmission Upgrade process.[6]

ISO-NE Economic Studies

ISO-NE has an Economic Study process, which is a launching pad for determining what types of transmission projects may be beneficial to the system beyond those in the traditional reliability planning process. In its Economic Study process, ISO-NE, in consultation with stakeholders,

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5 The Maine Power Reliability Program: About the Program, available at http://www.mainepower.com/program-overview.htm.

6 Another category of projects, merchant projects, is not discussed in this section. Merchant projects include transmission upgrades needed to connect a generator to the bulk power grid, and larger-scale projects that are operated on a merchant basis, called Merchant Transmission Facilities. The former are identified by ISO-NE as part of the generation interconnection process. The latter can be proposed by any market participant and submitted to the ISO-NE and its stakeholders for review and technical study. However, to date, the Cross Sound Cable project is the only Merchant Transmission Facility in ISO-NE.

selects up to three "what-if" resource or load expansion scenarios proposed by stakeholders to study per year. ISO-NE may include its own "what-if" scenarios in addition to the three selected. These scenarios are evaluated with customized metrics (e.g., production cost, congestion, emissions, and fuel mix). The Economic Study process may be followed by solutions studies or other activities to identify specific transmission solutions to address concerns rose in a given Economic Study. Solutions may include reliability projects, market efficiency projects, or Elective Transmission Upgrades.

The 2009 Economic Study[7] analyzed scenarios of renewables development at the request of New England policymakers, including up to 12,000 MW of wind development in New England and up to 3,000 MW of additional hydroelectric resources from Quebec and New Brunswick. This study focused on a long time horizon of 20 years, and was used as the technical basis for the 2009 New England Governor's Renewable Energy Blueprint.[8] Study findings included: (1) New England has significant potential to develop renewable resources and to expand ties with Canada; (2) assumed wind and imports scenarios could produce up to 26% of New England's energy, (3) transmission investment will be needed to integrate the new resources (estimated at $17-36B in the 26% energy case). In 2009, ISO-NE commissioned the New England Wind Integration Study (NEWIS),[9] which built off the findings of the 2009 Economic Study, and focused on the operational impacts of large-scale wind integration scenarios. NEWIS found that it would be operationally feasible to integrate wind resources to meet up to 24% of New England's energy if transmission upgrades comparable to those identified in the 2009 Economic Study were completed, and if requirements for ancillary services were increased.

The 2010 Economic Study expanded the 2009 Economic Study and analyzed the impacts of alternative resource mixes and relieving transmission constraints. The study analyzed a number of cases, including alternative retirement assumptions, CO_2 prices, renewables expansion, and conventional expansion scenarios.

2011 Economic Study also focused on wind development scenarios, but over a shorter near-term timeframe. This study analyzed the impact of potential resources at specific proposed locations informed by the ISO-NE generation queue. Among its findings, the 2011 study demonstrated the economic impact of adding new wind to the system, and of relieving constraints between the wind development areas and the rest of the system.

The 2012 Economic Study was developed in three phases. Phase I focused on evaluating the best and worst locations for changes in load and generating resources. Phase II evaluated various scenarios on fossil-based generating capacity, energy efficiency and renewable expansion, and impacts on system congestion, fuel use, and emissions. Phase III determined the level of capital investment that would be supported by the simulated energy market. The study found that resource retirements or load expansions in Boston and southwestern Connecticut created the most import-limiting constraints, and the resource additions or load reductions in Maine, New Hampshire, or Vermont created the most export-limiting constraints.

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7 Also referred to as the "Governors' Economic Study."

8 2009 New England Governor's Renewable Energy Blueprint, available at http://www.nescoe.com/Blueprint.html.

9 http://www.uwig.org/newis_es.pdf

The 2013 Economic Study investigated the economic and environmental metrics that could result from an increase in the largest loss-of-source (LOS) contingency allowed in New England resulting from an increase in needed operating reserves. Two study requests were submitted: one from National Grid, to analyze different levels of transfer over HQ Phase II to New England, and a second from New Brunswick Power Generation Corporation, to analyze increasing transfers from New Brunswick to Maine (specifically, to the Maine Electric Power Company).[10] New Brunswick Power Generation Corporation subsequently withdrew its request, as it had been determined that the question was already addressed in the 2012 Economic Study.[11] ISO-NE subsequently defined the 2013 Economic Study scope of work to analyze five different levels of maximum transfers on HQ Phase II, from 1,200 MW to 2,000 MW, and five different energy profiles for each maximum transfer level assumed, for a total of 20 scenarios analyzed.[12] For each scenario, ISO-NE calculated metrics on system impacts, including production cost, load-serving entity energy expense, average LMP, generation by fuel type, and generation emissions.[13]

The study found that for most scenarios, the various economic and environmental metrics showed lower costs and lower emissions, as the import level increased, and the energy was imported at an assumed $0/MWh cost. For most scenarios the production cost decreased when the HQ Phase II import level increased and the cost of HQ Phase II was assumed to be $0/MWh. For all scenarios, the LSE Energy Expense and system LMPs decreased as the maximum amount of HQ Phase II import levels increased. When the maximum amount of HQ Phase II import level increased, the imported energy displaced generation from gas, oil and coal units. [14]

ISO-NE did not receive any requests to conduct an economic study in 2014.

Elective Transmission Upgrades

If a proposed project is not selected to meet the needs identified in the Regional System Plan or Economic Study, and the project proposers wish to go forward with the project, the project must go through ISO-NE's Elective Transmission Upgrade (ETU) process for review and technical study. In that process, ETUs must go through the ISO-NE System Impact Study queue and receive technical approval. ISO-NE has recognized deficiencies with its ETU study process, including:[15]

- The process itself (e.g., timeline, milestones) does not provide enough certainty for ETU applicants;

10 ISO-NE Planning Advisory Committee Materials for April 24, 2013, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/apr242013/index.html.

11 Ibid.

12 ISO-NE Planning Advisory Committee, 2013 Economic Study Analysis of HQ Phase II Imports Scope of Work and Assumptions Update, July 9, 2013, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jul92013/a7_hq_phase2_imports_2013_economic_study.pdf.

13 Ibid.

14 2013 Economic Study, October 30, 2014, available at http://www.iso-ne.com/static-assets/documents/2014/10/2013_economic_study_final.pdf.

15 Kowalski, Richard V., Elective Transmission Upgrade Process Improvement, ISO-NE RC/TC Summer Meeting, July 22-23, 2013.

- Some structural misalignments between ETU-related studies and generator interconnection studies can prevent ETU-related studies from moving forward.

ISO-NE is currently developing an improved ETU study process that will add certainty and transparency, provide treatment comparable to generators, and provide enhanced interconnection services. ISO-NE is working towards developing an improved ETU study process and filing tariff and Market Rule changes with FERC in early 2015.[16]

Planning for Strategic and Public Policy Projects

Strategic and public policy-driven projects, especially those involving multi-state jurisdictions, face considerable challenges in the planning and development process. From the ISO-NE technical and reliability perspective, these projects are currently studied through the Economic Study and Elective Transmission Upgrade processes, but these processes are currently too narrow to enable a public policy project to move forward. From a policymaker's perspective, close state coordination in planning, and agreement on cost allocation among the involved states, are difficult but essential for moving a project forward beyond the ISO-NE technical studies.

A number of regional studies and initiatives in recent years have sought to improve planning coordination and to identify or set parameters for beneficial transmission projects, including:

- ISO-NE's Economic Studies, Strategic Transmission Analysis, and studies with the Eastern Interconnection Planning Collaborative;

- Regional policymaker initiatives, like the New England States Committee on Electricity (NESCOE), the New England Conference of Public Utilities Commissioners (NECPUC), Eastern Interconnection States Planning Council (EISPC);

- State policymaker initiatives to outline and clarify policy directives, like Connecticut's 2013 Comprehensive Energy Strategy and 2013 Restructuring Connecticut's Renewable Portfolio Standard reports; and

Most of these studies and initiatives focus specifically on transmission projects for the integration of renewable generation. In addition, FERC's Order No. 1000 calls for improvements to the region's planning process, including planning for public policy projects and cost allocation.

ISO-NE Strategic Planning Initiative (SPI) and Strategic Transmission Analysis

As part of its Strategic Planning Initiative, in 2013 ISO-NE conducted a Strategic Transmission Analysis, which (1) developed conceptual transmission additions that would enable onshore wind resources to serve load reliably, and (2) evaluated how the retirement of "at-risk" oil- and coal-fired generating units (8.3 GW) will affect system reliability. In the oil and coal retirement analysis, the Strategic Transmission Analysis also determined the most favorable locations for

[16] Rourke, Stephen J., Elective Transmission Upgrade Project Design Summary, ISO-NE Joint Transmission, Reliability and Markets Committee Meeting, November 17, 2014.

replacement capacity. Initial results of the study indicated that more than 950 MW of retirements would create system reliability issues, and that, if all 8.3 GW retires by 2020, 400 MW of replacement capacity must be in Connecticut.

Eastern Interconnection Planning Collaborative (EIPC)

EIPC was initiated by a coalition of regional U.S. and Canadian Planning Authorities, including ISO-NE.[17] In 2010, EIPC received $16 million in U.S. Department of Energy funding to initiate a multi-sector stakeholder and transparent collaborative transmission planning process.

The state regulators of 39 Eastern Interconnection states participate in the EIPC through the Eastern Interconnection States Planning Collaborative (EISPC). EIPC stakeholders include EISPC, Canadian entities, the U.S. federal government, transmission owners, generators, other suppliers, consumer advocates, other suppliers, and non-governmental organizations.

From 2010 through 2012, EIPC engaged in a two and a half-year process to study transmission needs among stakeholder-defined futures. This study was split into two phases. In Phase I, eight "futures" were defined, with most focusing on various future scenarios of carbon or climate policy, RPS policy, and demand-side resources. Phase I resulted in the selection of three transmission scenarios to be studied in Phase II:

- Scenario 1: Nationally-implemented federal carbon constraint with increased demand resources,
- Scenario 2: Regionally-implemented national RPS (30% by 2030), and
- Scenario 3: Business-as-usual (BAU).

The EIPC Phase I report was released in December, 2011.[18]

In Phase II, detailed transmission build-outs were developed for the three transmission scenarios developed in Phase I. For the year 2030 alone, a production cost analysis was performed on those scenarios, and costs for the transmission build-outs were estimated. The EIPC preliminary Phase II report was released at the end of 2012.[19] Among its results, the study found that Scenario 1 required the most new and upgraded transmission investment, with required investments concentrated in the more coal-intensive areas in the Eastern Interconnection. For New England, transmission build-out results among the three scenarios do not significantly differ. In Scenario 2 (RPS), the New England transmission build-out is almost the same as in Scenario 3 (BAU) because a significant amount of new wind generation (over 5,000 MW) was already assumed in Scenario 3. In Scenario 3, New England was estimated to need approximately $3.6-7.6B in transmission investments.

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17 More information available at http://www.eipconline.com/.

18 Eastern Interconnection Planning Collaborative, Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis. Available at http://www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf.

19 More information available at http://eipconline.com/Phase_II_Documents.html

Going forward, EIPC plans to continue with DOE-funded extensions to its Phase I and Phase II work, and to continue with non-grant Eastern Interconnection planning activities.[20]

Regional Policymaker Initiatives

In 2009, New England States Committee on Electricity released the 2009 New England Governor's Renewable Energy Blueprint. This study outlined the region's public policy objective to develop renewable generation and associated transmission more aggressively. The study relied on the ISO-NE 2009 Economic Study results (previously discussed) as a technical basis, and identified opportunities to coordinate siting review processes and resource procurements among the New England states.

New England policymakers also coordinate through the New England Conference of Public Utilities Commissioners. NECPUC is a non-profit corporation consisting of the utility regulatory bodies of the New England states.[21] State coordination under NECPUC includes collaboration with ISO-NE, regulatory filings, and annual symposiums.

Connecticut's Policy Initiatives

The Department's 2013 Comprehensive Energy Strategy for Connecticut report and 2013 Renewable Portfolio Standards study explored challenges and opportunities for meeting the state's renewable energy goals. These studies clarified policy objectives and recognized the need to develop both in-state and out-of-state renewable resources. The state's subsequent legislation under Connecticut Public Act (PA) 13-303 has successfully enabled procurements of renewable resources for the state, including new onshore wind resources in northern Maine. Future procurements under PA 13-303 may result in more procurement of new remote renewable resources, elevating the importance of resolving regional challenges with developing transmission for renewables integration.

FERC Order No. 1000 on Transmission Planning and Cost Allocation

FERC Order No. 1000 on "Transmission Planning and Cost Allocation" was issued on July 21, 2011.[22] The order requires all RTOs to reform their cost allocation and transmission planning procedures in ways that would ultimately improve regional transmission plans and stimulate transmission investment needed to meet public policy goals, such as renewable development. The order also requires utilities and RTOs to prepare and submit compliance filings. Specific requirements included in FERC Order No. 1000 are:

- Each public utility transmission provider participates in a regional transmission planning process that produces a regional transmission plan.
- Each public utility transmission provider amends its tariff to describe procedures that provides for the consideration of transmission needs driven by

[20] EIPC, EIPC Results and Next Steps, presentation to the ISO-NE PAC, April 24, 2013, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/apr242013/index.html.
[21] http://necpuc.org/index.cfm
[22] http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

public policy requirements in the local and regional transmission planning processes.

- Removes a federal right of first refusal for incumbent utilities from Commission-approved tariffs and agreements for certain new transmission facilities.

- Seeks to improve coordination between neighboring transmission planning regions for new interregional transmission facilities.

- Each public utility transmission provider must participate in a regional transmission planning process that has: (1) a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of certain new transmission facilities that are located in two or more neighboring transmission planning regions and are jointly evaluated by the regions in the interregional transmission coordination procedures.

Improvements in the regional planning process pursuant to FERC Order No. 1000 are important for strategic and policy-driven projects, particularly those involving better consideration of transmission needs and regional and interregional cost allocation. ISO-NE, in coordination with the transmission owners and other stakeholders, submitted the first of two required compliance filing in October 2012,[23] with proposed revisions for cost allocation and planning. ISO-NE submitted the second filing in July 2013,[24] outlining changes to its interregional planning process.

ISO-NE outlined several proposed changes to the planning process for strategic and public policy projects in its October 2012 FERC Order No. 1000 compliance filing. In the filing, ISO-NE proposed that the New England State Committee on Electricity would ensure coordination of NE states in public policy projects identification and selection. Building off the current Economic Studies process, NESCOE would identify state and federal public policies, which would focus on renewables integration in support of state Renewable Portfolio Standards, for further study by ISO-NE. In its proposal, ISO-NE outlined a process to allow New England states to identify projects needed to meet public policy goals, such as reaching new wind, and submit them to their respective Public Utilities Commission (PUC) or to NESCOE. ISO-NE also proposed a "load-pays" cost allocation method based on ratio of each project sponsor's load.

In the July, 2013 filing, at an interregional level, ISO-NE proposed that the Joint ISO/RTO Planning Committee (JIPC) and ISO-NE's Inter-Area Planning Stakeholder Advisory Committee (IPSAC) would create a new extensive stakeholder planning process. The JIPC would coordinate interregional planning activities and facilitate resolution of any issues that arise. They would also develop a northeastern coordinated system plan, undertaking periodic interregional assessments

23 http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13095847
24 http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13303313

and system planning expansion studies. The IPSAC would provide feedback on JIPC's review of regional needs and solutions.

In May, FERC conditionally accepted the October 2012 compliance filing, pending the following revisions:

> *Public Policy Projects* - ISO-NE has been asked to expand the definition of a public policy project to include laws and statues passed by local governments.
>
> *Cost Allocation* - FERC rejected ISO-NE's proposed new cost-allocation method for public policy projects because it would allow states to easily opt out of allocation if they declare there is no benefit for them, potentially dumping costs onto other states. FERC asked for further clarification on enrollment in and transition to the revised regional transmission planning process as well as revise the process to increase transparency and participation.
>
> *Regional Transmission Planning* - On planning issues, FERC directed the ISO-NE to develop an appropriate effective date for the changes that would coincide with the beginning of an ISO-NE planning cycle. The RTO also was asked to clarify the regional transmission planning enrollment process, as well as the transition to the revised regional transmission planning process. Finally, FERC required language exempting needs identified in Regional System Plans or other needs assessment completed prior to FERC 1000's effective date from being subject to its requirements.

On November 15, 2013, ISO NE made a compliance filing with FERC regarding Order No. 1000 intra-regional cost allocation. ISO NE proposes that cost allocation for projects with public policy need be done on 70/30 basis. 70% of costs is allocated region wide and 30% is allocated to states with an identified public need. The proposal is still under review by the FERC.

ISO-NE's second filing in July 2013 outlined a new "stakeholder process" for interregional planning, as well as a cost allocation methodology for interregional projects. These proposals are still under review by the FERC.

TRANSMISSION RELIABILITY NEEDS AND STUDIES IN CONNECTICUT

There are three transmission reliability sub-area studies currently in progress in Connecticut. These studies, performed in collaboration with ISO-NE, are at various stages in the ISO-NE regional planning process. They are as follows:

1. Southwest Connecticut Needs Assessment and Solution Study were completed in 2014.

2. Greater Hartford/Central Connecticut Needs Assessment. This study includes a needs assessment of the Greater Hartford area (including Northwestern Connecticut, Manchester, and Middletown areas) and a reassessment of the Central Connecticut Reliability Project portion of the New England East West Solution. The GHCC Solution alternatives are being developed.

3. Eastern Connecticut Needs Assessment was completed in 2013. The Solutions Study including alternatives is being developed.

Potential reliability concerns and alternatives under evaluation are described below.

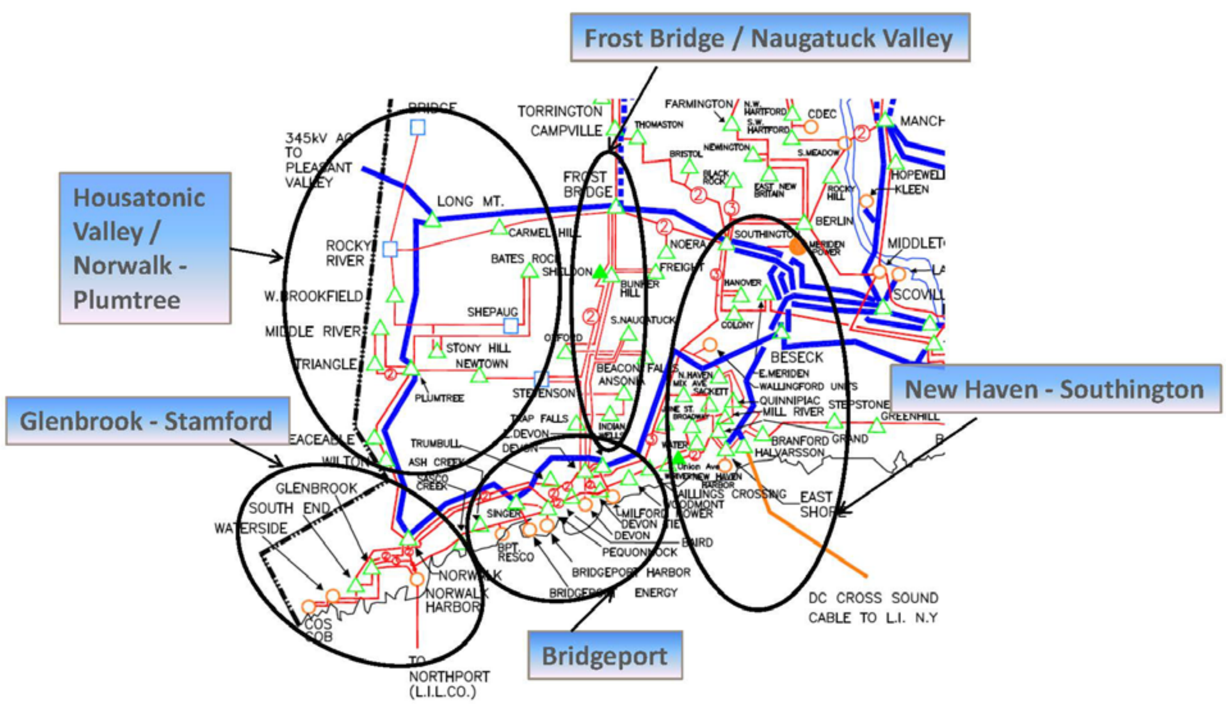
Southwest Connecticut Needs Assessment and Solution Study

The "Southwest Connecticut Area Transmission 2022 Needs Assessment" study report was finalized by ISO-NE in June of 2014. The Southwest Connecticut 2022 Preferred Solutions Selection was presented to PAC in July of 2014[25]. The Southwest Connecticut (SWCT) study area was divided into the following five sub-areas for the purpose of this study and the subsequent Solution Study:

Frost Bridge - Naugatuck Valley Subarea
Housatonic Valley / Norwalk – Plumtree Subarea
Bridgeport Subarea
New Haven – Southington Subarea
Glenbrook – Stamford Subarea

Figure 4 shows the approximate location of these sub areas.

Figure 4 Southwest Connecticut Study Areas



25 The ISO-NE SWCT 2022 Needs Assessment is available on the ISO-NE website at: https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2014/final_swct_2022_needs.pdf

The reliability concerns (*i.e.*, needs) identified in each of these areas continue to be related to thermal, voltage, or short-circuit performance in accordance with NERC, NPCC, and ISO-NE reliability criteria.

A new needs assessment and solutions study, referred to as the *2022 SWCT Needs Assessment and Solutions Study*, was initiated to take into account the latest assumptions, changes in topology resulting from the approval of new projects and the results of the latest FCA, and the inclusion of energy efficiency beyond the latest FCA. The 2022 SWCT needs were first presented to the PAC in May 2013. Bridgeport Harbor 2 has already retired, and Norwalk Harbor station will retire by June 2017. As a result, the 2022 SWCT needs were reevaluated, and the needs assessment was presented to the PAC in February 2014.[26] Needs were still present in all subareas with the exception of the Glenbrook–Stamford subarea. The advanced Glenbrook–South End cable mitigated all the violations found in the earlier needs assessment.

As part of the solution development, the two categories of solution were developed: "local" and "global." As detailed below, local solutions located in each subarea were developed for each subarea listed below. In addition, a global solution, which spans the subareas of Frost Bridge–Naugatuck Valley and Housatonic Valley–Norwalk–Plumtree subareas, was created. The main feature of the global solution was a new line from Bates Rock to Bunker Hill, which required the rebuild of both terminal stations. Because of the excessive cost of the global solution, it is not the preferred alternative and is no longer being considered.

The major components of the preferred solutions for addressing the needs in the Frost Bridge–Naugatuck Valley subareas include the following components:

- Loop the 1570 line (Devon to Beacon Falls) in and out of the Pootatuck substation (formerly known as Shelton substation)
- Install two 115 kV capacitor banks at Ansonia substation
- Expand Pootatuck substation to a four-breaker ring bus and install a 115 kV capacitor bank
- Close the normally open breaker at Baldwin substation
- Install a 115 kV capacitor bank at Oxford substation
- Loop the 1990 line (Stevenson–Baldwin Street–Frost Bridge) in and out of the Bunker Hill substation
- Rebuild Bunker Hill substation to a nine-breaker, breaker-and-a-half configuration
- Reconductor the 1575 line from Bunker Hill to Baldwin Junction

The major components of the preferred solutions for addressing the needs in the Housatonic Valley/Norwalk/Plumtree subareas include a combination of the following components:

- Reconductor the 1887 line between West Brookfield and West Brookfield Junction

[26] *Southwest Connecticut 2022 Needs Assessment* II (February 19, 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/feb192014/a9_swct_needs_assessment_2.pdf. *Southwest Connecticut Area Transmission 2022 Needs Assessment* (June 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2014/final_swct_2022_needs.pdf.

- Install two 14.4 MVAR capacitor banks at West Brookfield substation
- Reduce the size of the capacitor at Rocky River substation from 25.2 MVAR to 14.4 MVAR
- Relocate a 37.8 MVAR capacitor bank within the Stony Hill substation
- Install one synchronous condenser at Stony Hill substation
- Reconfigure the 1887 line into a three-terminal line (Plumtree–W. Brookfield–Shepaug)
- Reconfigure the 1770 line into two two-terminal lines between Plumtree–Stony Hill and Stony Hill–Bates Rock
- Reconductor a portion of the 1682 line from Wilton to Norwalk, and upgrade Wilton substation terminal equipment
- Reconductor the 1470 line from Wilton to Ridgefield Junction and Ridgefield Junction to Peaceable
- Install a 115 kV breaker in series with the existing 29T breaker at Plumtree substation
- Install a new 115 kV line from Plumtree to Brookfield Junction
- Relocate one existing capacitor bank from the 115 kV B bus to the 115 kV A bus at Plumtree substation
- Upgrade the 1876 line terminal equipment at Newtown substation

The preferred solution for addressing the needs in the Bridgeport and New Haven areas include the following components:

- Upgrade the Baird 115 kV bus
- Install two 115 kV capacitor banks at Hawthorne
- Upgrade the 115 kV bus system and 11 disconnect switches to 63 kA interrupting capability at Pequonnock
- Rebuild the 8809A/8909B lines from Baird to Congress
- Install a series breaker at East Devon
- Remove the Sackett phase-angle regulator (PAR)
- Install a series reactor on the 1610 line (Southington–June–Mix Ave) and two 115 kV capacitor banks at Mix Avenue
- Rebuild the 88005A/89005B lines from Devon Tie to Milvon
- Replace two 115 kV breakers at Mill River to address short circuit and TRV overduty issues
- Upgrade the 1630 line (North Haven–Wallingford–Walrec) relay at North Haven
- Separate the 3827 (Beseck–East Devon)–1610 (Southington–June–Mix Ave) double-circuit towers
- Rebuild the 88006A/89006B lines from the Housatonic River Crossing to Baird

As part of the development of solutions in SWCT, the preferred solution for meeting short-circuit criteria at Pequonnock was to delay the circuit-breaker fault-clearing time to reduce the interrupt duty. The solution includes the complete replacement of the transmission control house and relays to incorporate the additional time delay in the tripping logic. With the upcoming retirement of Norwalk Harbor station and Bridgeport Harbor 2, the control house and new relays are no longer needed. However, the need persists to replace bus work and disconnect switches at the Pequonnock station to address short-circuit concerns.

On July 15, 2014, ISO-NE presented the SWCT Area 2022 Preferred Solutions selection[27]. The SWCT Area 2022 Solutions Study report has been updated accordingly, in December of 2014[28].

GHCC Needs Assessment

A transmission reliability needs assessment for the Greater Hartford area, and a needs reassessment associated with the Central Connecticut component of the New England East West Solution Project have been combined into one study.[29] The scope of this study has also been expanded to include the Manchester, Middletown, and Northwestern Connecticut areas.

The Greater Hartford transmission system experiences flow-through and load-supply issues under certain dispatch patterns, contingency conditions, and transfer conditions. The reliability concerns (*i.e.*, needs) identified in each of these areas are related to thermal, voltage, or short-circuit performance in accordance with NERC, NPCC, and ISO-NE reliability criteria.

As shown in Figure 5, below, the Greater Hartford/Central Connecticut area has been divided into following four sub-areas for the purposes of this study:

Greater Hartford

Northwestern Connecticut

Middletown

Manchester/Barbour Hill

[27] The ISO-NE SWCT 2022 Preferred Solution Selection presentation to PAC on July 15, 2014 is available on the ISO-NE website at: https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/jul152014/a9_swct_2022_preferred_solutions.pdf

[28] The ISO-NE SWCT Area Transmission 2022 Solutions Study Report is available on ISO-NE website at: https://smd.iso-ne.com/planning/ceii/reports/2010s/draft_swct_2022_solutions_study_report.pdf

[29] Scope of Work (March 16, 2011), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/mar162011/ghcc.pdf.

The needs assessment for this study shows 115kV violations in all four subareas at 2013 load levels that reflect both local load serving needs and a need for greater Western CT import capacity.[30]

The GHCC Solutions Study was presented to PAC in July 2014.[31] Solutions were developed for each subarea listed above. The major components of the preferred solutions for each subarea are highlighted below:

- Manchester–Barbour Hill
  - Add a new 345/115 kV autotransformer at Barbour Hill
  - Upgrade the 115 kV line from Manchester to Barbour Hill (1763)
  - Add a series breaker at Manchester 345 kV switchyard
- Northwestern Connecticut
  - Add a new 115 kV line from Frost Bridge to Campville substation
  - Separate the 115 kV lines from Frost Bridge to Campville and from Thomaston to Campville DCT, and add a 115 kV breaker at Campville
  - Upgrade terminal equipment on the 115 kV line between Chippen Hill and Lake Avenue Junction (1810-3)
  - Reconductor the 115 kV line between Southington and Lake Avenue Junction (1810-1)
- Greater Hartford, including Southington
  - Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with 5% series reactors
  - Replace the normally open 19T breaker at Southington with a 3% series reactor between Southington ring 1 and Southington ring 2 and associated substation upgrades
  - Add a breaker in series with breaker 5T at the Southington 345 kV switchyard
  - Add a new control house at Southington 115 kV substation
  - Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment, including a 2% reactor
  - Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation, and reconfigure the Rood Avenue substation
  - Reconfigure the Berlin 115 kV substation, including the addition of two 115 kV breakers and the relocation of a capacitor bank

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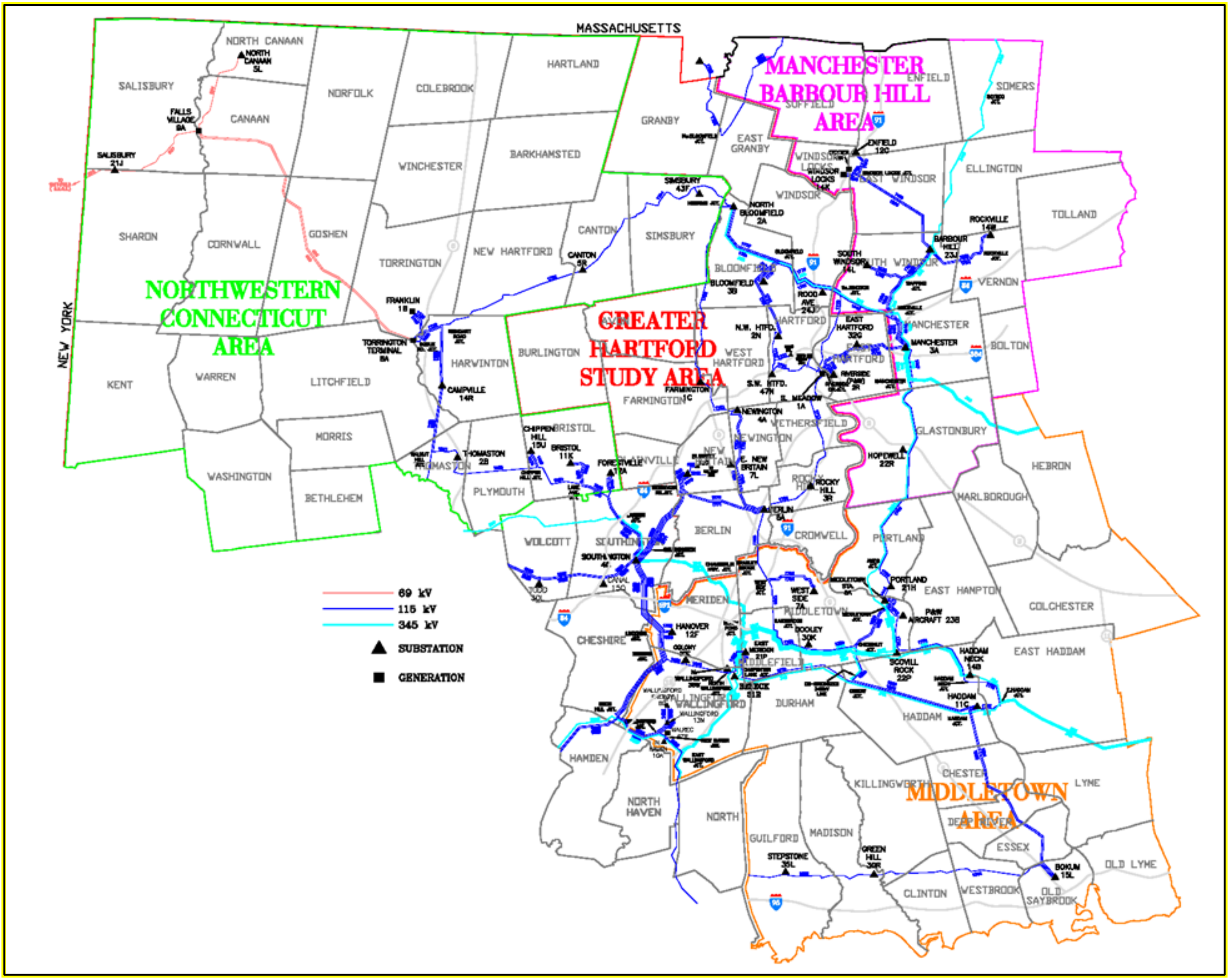
30 Greater Hartford and Central Connecticut Area (GHCC) Needs Assessment III, Nov. 20, 2013, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/index.html p. 35

31 Vijayan, Pradip, Greater Hartford and Central Connecticut Area (GHCC) Solutions Study II, Planning Advisory Committee meeting, July 15, 2014.

  - Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation
  - Reconductor the 115 kV line between Newington and Newington Tap (1783)
  - Separate the 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line, and add a breaker at Bloomfield 115 kV substation
  - Install a 115 kV 3% reactor on the underground cable between South Meadow and Southwest Hartford (1704)
  - Separate the 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield–Rood Avenue–Northwest Hartford (1751) line, and add a breaker at North Bloomfield 115 kV substation
- Middletown
  - Add a second 345/115 kV autotransformer at Haddam substation, and reconfigure the three- terminal 345 kV 348 line into 2 two-terminal lines
  - Upgrade terminal equipment on the 345 kV line between Haddam and Beseck (362)
  - Separate the 115 kV DCT corresponding to the Branford–Branford RR line (1537) and the Branford to North Haven (1655) line and add a series breaker at Branford 115 kV substation
  - Redesign the Green Hill 115 kV substation from a straight bus to a ring bus, and add a 37.8 MVAR capacitor bank
  - Upgrade terminal equipment on the Middletown to Dooley line (1050)
  - Upgrade terminal equipment on the Middletown to Portland line (1443)
  - Add a 37.8 MVAR capacitor bank at Hopewell 115 kV substation
  - Separate the 115 kV DCT corresponding to the Middletown–Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line

Figure 5
Greater Hartford–Central Connecticut Study Areas



Eastern Connecticut Needs Assessment

In April 2013 ISO-NE approved the scope of work for the Eastern Connecticut Needs Assessment Study. The Needs Assessment results were presented to PAC in July of 2013.

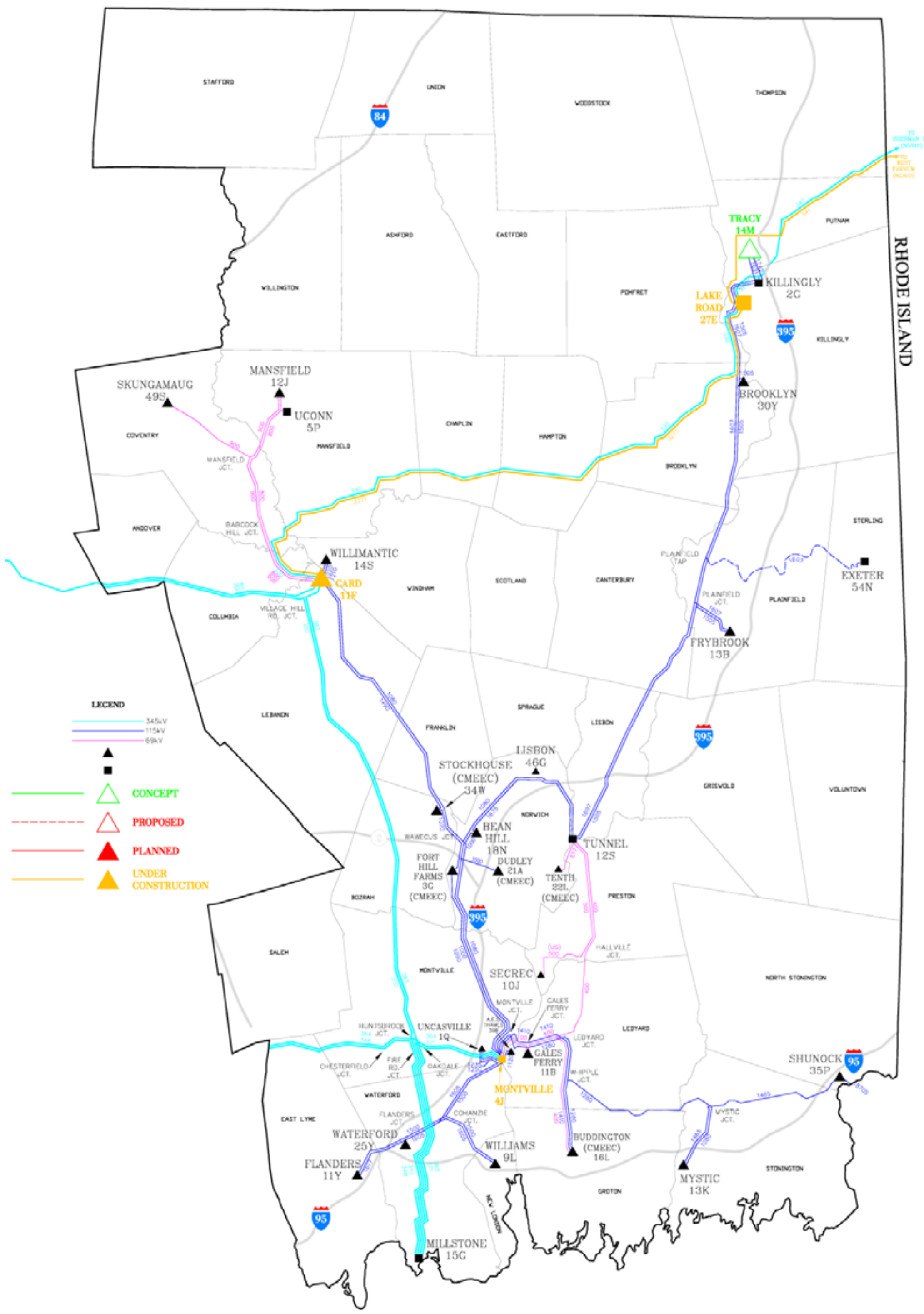
The area, shown in Figure 6, encompasses the 115-kV load pocket that is served by 345/115-kV autotransformers at Montville, Card, and Killingly Substations and the 115-kV tie between Rhode Island and Connecticut. In addition to the transmission sources, the load pocket is supplied by generation at Montville, UCONN, Exeter, Plainfield Energy, Tunnel, and Lisbon generating facilities.

The thermal and voltage reliability criteria violations associated with the area result from double circuit tower and stuck circuit breakers contingencies that are paired with loss of a 345/115-kV autotransformer.

The potential solutions consist of additional 345/115-kV autotransformers as well as 115-kV capacitors and line reconductoring and/or rebuilding. The solution alternatives are being developed.

Figure 6

Eastern Connecticut Study Areas



NON-TRANSMISSION ALTERNATIVES FOR RELIABILITY

In 2009, DEEP began developing a process for evaluating non-transmission resources as potential alternatives to reliability transmission projects located in Connecticut. Since that time, Connecticut regulators and EDCs have worked with each other and in coordination with ISO-NE and NESCOE to refine the conceptual NTA process. In October 2012, NESCOE published its Regional Framework for Non-Transmission Alternatives Analysis.[32]

Prior IRPs described the motivations for the NTA process and its conceptual development in detail. In this section, the Department provides a brief summary of the final NESCOE framework, along with specific examples of reliability transmission projects in Connecticut that may be suitable for the NTA process.

NTA Process

In its report, NESCOE outlined four objectives of the NTA process:

1. To obtain NTA analysis at a point in time in the regional planning process when such analysis provides more practical value to states and market participants than the alternative analysis TOs produce today does.

2. To make state siting processes more efficient by reducing the need for states to ask TOs for additional analysis during siting proceedings.

3. To obtain more uniform alternative analysis across the region.

4. To conduct NTA planning analyses in an open and transparent process.

Figure 7 shows a summary of the NESCOE NTA process, and how consideration of NTAs fit into the interconnected Transmission Owner (TO) and ISO-NE/regional planning processes. NTAs would be conceptualized in response to results of the ISO-NE/regional needs assessments, and specific solutions would be developed in parallel with transmission reliability backstop solution studies. At the state level, transmission and NTA solutions would be reviewed for design, environmental impacts, siting, economic and policy analysis, in parallel. Finally, TOs would submit final transmission-only, NTA-only, or hybrid solutions for ISO-NE technical approval (§I.3.9).

ISO-NE, while it has recognized that the proposed NTA process can add value to the current transmission planning process, is only in the initial stages of implementing an NTA process. Using the term "Market Resource Alternative" (MRA), ISO-NE has conducted two pilot studies to analyze MRAs in the New Hampshire/Vermont and GHCC areas. ISO-NE found these studies to be overly time-consuming and labor-intensive, and is in the process of reassessing how best to implement the MRA process.

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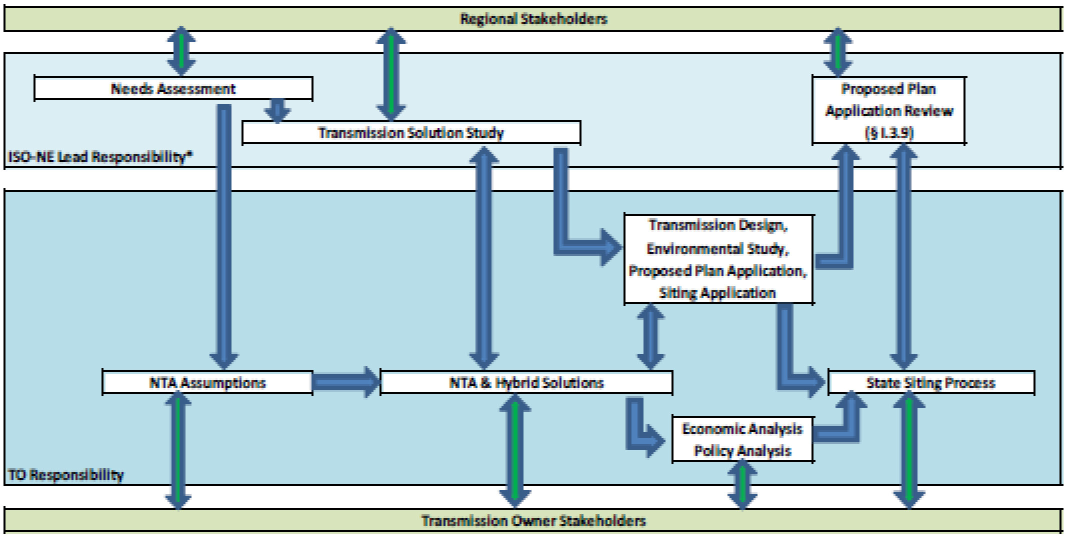
[32] Regional Framework For Non-Transmission Alternatives Analysis. Available at http://www.nescoe.com/uploads/NTA_Framework_October_2012_FINAL.pdf.

Figure 7
NTA Alignment of Markets with Planning[33]



* ISO-NE Lead Responsibility - analysis may be conducted by the TO or other members of the Study Group
* Analysis Steps are depicted by the boxes and blue information arrows; stakeholder involvement is depicted in green information arrows
NOTE: This diagram does not include any of the ISO's proposed MRA processes

Types of Reliability Projects That May Be Suitable for NTAs

In prior IRPs, the criteria outlined in Figure 8 were used for illustrating reliability projects/needs in Connecticut that may be viable candidates for the consideration of non-transmission alternatives. These criteria serve to clarify the characteristics of transmission projects considered or planned for Connecticut in the ISO-NE Regional System Plan and the ISO-NE area needs assessment reports that may be considered as possible NTA candidates. Categories A (new substations) and B (infrastructure upgrades) are unlikely to have viable non-transmission alternatives. For Category C (new transmission lines) and new infrastructure considered in reliability studies, viable non-transmission alternatives may be identifiable through an RFP process.

Figure 8

33 NESCOE, Regional Framework for Non-Transmission Alternatives, October 2012. Available at http://www.nescoe.com/uploads/NTA_Framework_October_2012_FINAL.pdf.

Transmission Reliability Project Categories

New Substation Facilities Category (A)	Infrastructure Upgrades Category (B)	New Transmission Lines Category (C)	Reliability Studies in Connecticut
• New planned substation facilities • Statutory change exempted this type of project from Reactive RFP • See Figure 9	• Reliability upgrades to existing equipment, for example; capacitor bank upgrades, circuit breaker replacement, relaying upgrades, transformers, and other existing transmission infrastructure • See Figure 10	• New transmission lines (typically 115 kV or 345 kV) • Address reliability needs that cannot be resolved by upgrading existing infrastructure • See Figure 11	• Reliability assessments are currently underway by ISO-NE and the TOs for various areas in Connecticut • See "Transmission Reliability Needs and Studies in Connecticut"

RFPs are not likely to result in viable alternatives (Categories A and B)

Under certain circumstances, RFPs may be applicable for soliciting alternatives (Category C and Reliability Studies)

Figures 9, 10, and 11 provide a summary of Connecticut transmission reliability projects shown in the Project Listing dated October 2014. The projects are grouped into the categories summarized in Figure 7 (A, B, or C).

Figure 9
Category A — New Substations (and Significant Additions)

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Pootatuck S/S	Shelton	UI	721	New 115/13.8 kV substation	2015	Under Construction
Montville	Montville	Eversource	1607	Replace two 345/115 kV autotransformers	2015	Under Construction
Hawthorne 115 kV Capacitor Bank Addition	Fairfield	UI	1389	Add a 115 kV capacitor bank	2016	Planned
Mix Ave 115 kV Capacitor Bank & Reactor Additions	Hamden	UI	1386	Add a 115 kV capacitor bank and series reactor	2017	Planned
Sacket 115 kV PAR Removal	North Haven	UI	1388	Remove 115 kV phase angle regulator	2017	Planned
Ansonia 115 kV Capacitor Bank Addition	Ansonia	UI	1620	Add two 115 kV capacitor banks	2017	Proposed
Pootatuck 115 kV Ring Bus Expansion and Capacitor Bank Addition	Shelton	UI	1621	Add three 115 kV circuit breakers and a 115 kV capacitor bank	2017	Proposed
Canal	SWCT	Eversource	LSP*	Add 115/23 kV transformer	2016	Concept
Tracy	Eastern	Eversource	LSP*	Add 115/23 kV transformer and 115kV breaker	2016	Concept
Greenwich	Greenwich	Eversource	LSP*	New 115/27 kV substation	2017	Planned
Cos Cob	Greenwich	Eversource	1533	Cos Cob Breaker Addition	2017	Planned
Burrville	Northwest	Eversource	LSP*	New 115/23 kV substation	2018	Concept
North Bloomfield	Greater Hartford	Eversource	LSP*	Add a 115/23 kV transformer	2020	Concept
East Devon	SWCT	Eversource	1399	Install 11T 345 kV series breaker	TBD	Planned
Oxford	SWCT	Eversource	1559	Add a 115 kV capacitor bank	2017	Proposed
Baldwin	SWCT	Eversource	1560	Close 115 kV breaker	2017	Proposed
Plumtree	SWCT	Eversource	1562	Install a 115 kV breaker	2017	Proposed
West Brookfield	SWCT	Eversource	1563	Add two115 kV capacitor banks	2017	Proposed
Plumtree	SWCT	Eversource	1565	Relocate 115 kV capacitor bank	2017	Proposed
Rocky River	SWCT	Eversource	1567	Reduce 115 kV capacitor banks	2017	Proposed
Freight	SWCT	Eversource	1570	Replace two 115 kV	2017	Proposed

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
				breakers		
Bunker Hill	SWCT	Eversource	1571	Rebuild Substation	2017	Proposed
Stony Hill	SWCT	Eversource	1576 & 1578	Relocate 115 kV capacitor and add Dynamic Device	2017	Proposed
Newtown	SWCT	Eversource	1566	Upgrade 1876 line terminal	2017	Proposed
Barbour Hill	GHCC	Eversource	1580	Add a 345/115 kV autotransformer	2017	Proposed
Manchester	GHCC	Eversource	1582	Add a 345 kV breaker	2017	Proposed
Southington	GHCC	Eversource	1588 &1589	Add a 345 kV breaker & Control House	2017	Proposed
Rood Ave	GHCC	Eversource	1591	Reconfigure Rood Ave substation & loop 1779 115 kV Line in and out	2017	Proposed
Berlin	GHCC	Eversource	1592	Reconfigure Berlin substation& add two115 kV breakers	2017	Proposed
Westside	GHCC	Eversource	1593	Add a 115 kV capacitor bank	2017	Proposed
Haddam	GHCC	Eversource	1598	Add a 345/115 kV autotransformer	2017	Proposed
Green Hill	GHCC	Eversource	1603	Redesign substation & Add a 115 kV capacitor bank	2017	Proposed
Hopewell	GHCC	Eversource	1604	Add a 115 kV capacitor bank	2017	Proposed

* Local System Plan.

Figure 10
Category B — Infrastructure Upgrades

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Bulls Bridge 11M Add 27.6kV (New Milford)	SWCT	Eversource	LSP	Replace existing transformer with a new dual voltage transformer	2015	Proposed
Housatonic River Crossing 88006A & 89006B 115 kV Line Rebuild	Milford - Stratford	UI	1555	Upgrade 115 kV lines across Housatonic River	2016	Planned
Milvon to Devon Tie 88005A – 89005B 115 kV Line Upgrade	Milford	UI	1384	Upgrade 115 kV lines (Milvon – Devon Tie)	2016	Planned
Baird 115/13.8 kV Substation Rebuild (Baird 115 kV Bus Upgrade)	Stratford	UI	1381	Rebuild 115/13.8 kV substation including 115 kV bus	2017	Planned
Baird to Congress 8809A – 8909B 115 kV Line Upgrade	Stratford & Bridgeport	UI	1380	Upgrade 115 kV lines (Baird – Congress)	2017	Planned
Baird to Housatonic River Crossing 88006A-89006B 115 kV Line Upgrades	Stratford	UI	1622	Upgrade 115 kV lines (Baird – Housatonic River)	2018	Proposed
Old Town 115/13.8 kV Substation Rebuild	Bridgeport	UI	1618	Rebuild 115/13.8 kV Substation	2019	Planned
W. Brookfield-W.Brookfield Jct.	SWCT	Eversource	1561	Reconductor 115 kV Line	2017	Proposed
Beacon Falls-Indian Wells-Devon 1570 Line	SWCT	Eversource	1568	Loop 115 kV line in and out of Pootatuck	2017	Proposed
FrostBridge-Baldwin-Stevenson 1990 Line	SWCT	Eversource	1569	Loop 115 kV Line in and out of Bunker Hill	2017	Proposed
Wilton-Norwalk 1682 Line Upgrade	SWCT	Eversource	1572	Rebuild a portion of the 115 kV Line	2017	Proposed
Wilton-Ridgefield 1470-1 Line Upgrade	SWCT	Eversource	1573	Reconductor 115 kV Line	2017	Proposed
Peaceable-Ridgefield Jct. 1470-3 Line Upgrade	SWCT	Eversource	1574	Reconductor 115 kV Line	2017	Proposed
Bunker Hill-Baldwin Jct 1575-1 Line Upgrade	SWCT	Eversource	1575	Reconductor 115 kV Line	2017	Proposed

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Plumtree-W.Brookfield-Shepaug 1887 & 1770 Plumtree-Stony Hill Bates Rock	SWCT	Eversource	1577	Reconfigure both 115 kV lines	2017	Proposed
3827-1610 Double Circuit Separation	SWCT	Eversource	1579	Separate the Double Circuit line	2017	Proposed
Manchester-Barbour Hill 1763 Line	GHCC	Eversource	1581	Reconductor 115 kV Line	2017	Proposed
Frost Bridge-Campville 1191&Thomaston-Campville 1921 Lines & Campville substation	GHCC	Eversource	1584	1191 & 1921 Line separation & add a 115 kV breaker at Campville	2017	Proposed
Upgrade Chippen Hill-Lake Ave Jct. 1810-3&Souhtington-Lake ave Jct. 1810-1 Upgrade	GHCC	Eversource	1585	Upgrade terminal equipment 1810-3&reconductor 1810-1 115 kV Line	2017	Proposed
Upgrade Southington-Todd 1910 & Southington-Canal 1950 Lines	GHCC	Eversource	1586	Replace 3% series reactors with 5%	2017	Proposed
Upgrade Southington Substation	GHCC	Eversource	1587	Replace 115 kV breaker with 3% reactor	2017	Proposed
Newington-Newington tap 1783 115 kV Line	GHCC	Eversource	1594	Reconductor 115 kV Line	2017	Proposed
Bloomfield-South Meadow 1779 & Bloomfield-North Bloomfield 1777 Lines	GHCC	Eversource	1595	Separate the 1779 & 1777 115 kV Lines& add a 115 kV breaker at Bloomfield substation	2017	Proposed
Upgrade South Meadow-SW Hartford 1704 115 kV Line	GHCC	Eversource	1596	Install a 3% reactor on 1704 115 kV Line	2017	Proposed
Bloomfield-North Bloomfield 1777 & North Bloomfield-NW Hartford 1751 Lines	GHCC	Eversource	1597	Separate the 1777 & 1751 115 kV Lines and a 115 kV breaker at North Bloomfield substation	2017	Proposed

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
Upgrade Haddam-Beseck 362 345 kV Line	GHCC	Eversource	1599	Terminal equipment upgrade	2017	Proposed
Branford-Branford RR 1537 & Branford-North Haven 1655 115 kV Lines	GHCC	Eversource	1600	Separate the 1537 & 1655 115 kV Lines and a 115 kV breaker at Branford substation	2017	Proposed
Upgrade Middletown-Dooley 1050 115 kV Line	GHCC	Eversource	1601	Terminal equipment upgrade	2017	Proposed
Upgrade Middletown-Portland 1443 115 kV Line	GHCC	Eversource	1602	Terminal equipment upgrade	2017	Proposed
Upgrade Middletown-Pratt&Whitney 1572 & Middletown-Haddam 1620 115 kV Lines	GHCC	Eversource	1605	Separate the 1572 &1620 115 kV Lines	2017	Proposed
South Meadow-Bloomfield 1779 Line	Greater Hartford	Eversource	1606	Partial rebuild of the 115 kV Line	2017	Proposed

Figure 11
Category C — New Transmission Lines

Project Name	Location	Owner	RSP Project ID	Description	Projected In-Service Year	Status
NEEWS	CT/RI/MA	Eversource	802 810, 191 1085	Interstate Reliability Project	2015	Under Construction
Cos Cob-Greenwich	Greenwich	Eversource	LSP	New 115 kV Line	2017	Planned
Cos Cob-Greenwich	Greenwich	Eversource	LSP	New 115-kV Line	2017	Planned
Plumtree-Brookfield Jct.	SWCT	Eversource	1564	New 115 kV Line	2017	Proposed
Frost Bridge-Campville	GHCC	Eversource	1583	New 115 kV Line	2017	Proposed
Newington-SW Hartford	GHCC	Eversource	1590	New 115 kV Line	2017	Proposed

TRANSMISSION PLANNING FOR RENEWABLES

Transmission development for renewables has received a great deal of attention in New England in recent years. This is partially driven by New England states' increased focus on meeting Renewable Portfolio Standards. Focus on transmission for renewables is also driven by the considerable challenges in planning for, and paying for, this type of transmission. The potential magnitude of transmission investment needed to integrate an even modest amount of new renewables in the region raises critical questions about how transmission solutions for renewables would be identified, how the costs versus benefits would be evaluated, and who would pay for the investment. The sections below address these fundamental questions.

Transmission for Renewables: Challenges in New England

New England has great potential for renewable resource development, with up to 215 GW as a technical potential for wind generation.[34] Harnessing these resources could provide energy independence, environmental, and economic benefits for the region, but these benefits must be weighed against the costs, including transmission investments needed to integrate renewables.[35]

The highest-quality wind resources are located in Maine, far from load centers, and new transmission lines would be needed to connect them. The current transmission system is already operating close to its limits resulting in curtailment of existing wind resources due to transmission constraints.[36] Adding more wind resources would likely require substantial

[34] 2009 Northeast Coordinated System Plan (May 24, 2010).
[35] Additional costs of renewable integration include operational costs related to planning and balancing challenges of intermittent generation. These costs are discussed in later sections.
[36] New England Wind Integration Study, 2010, page 8.

investment in new transmission, which is a point that several wind integration studies has emphasized. For example, the 2009 Governor's Study estimated that New England could integrate 5,500 MW of new wind capacity with $5-8 billion in transmission investment and 8,000 MW of new wind capacity with more than $13 billion. The 2010 New England Wind Integration Study (NEWIS) by GE Energy supported this and found the transmission overlays outlined in the 2009 Governor's Study could enable enough wind generation to make up 20-24% of the region's total annual electric energy needs in 2020 without significant congestion in the system.[37] While the results and cost figures presented in these studies are preliminary and illustrative, they highlight the importance of transmission for renewables development and the range of likely investments needed.

Identifying Transmission Solutions for Renewables

New England has made some progress in this area in recent years. For example, ISO-NE's Economic Studies, EIPC's Phase II report, and policymaker initiatives (through NESCOE, NECPUC, and EISPC) have coordinated the efforts of a wide scope of stakeholders and attempted to clarify public policy objectives.

One challenge going forward will be for New England to include evaluation of strategic and public policy projects into a more integrated transmission planning process. Currently, ISO-NE's Regional System Plan is almost exclusively reliability-focused, even though it also considers market efficiency (also referred to as "economic") projects. ISO-NE's Economic Study process evaluates future load and resource scenarios, but is not designed to evaluate specific transmission solutions to meet public policy objectives such as RPS targets. In contrast, for example, MISO's transmission expansion plan (MTEP) evaluates Multi-Value Projects using a portfolio approach to identify transmission projects needed to address energy policy objectives and provide widespread benefits across its footprint. Similarly, SPP's integrated transmission planning (ITP) process considers the region's public policy needs and studies various transmission project portfolios to address these needs cost-effectively. ISO-NE and its stakeholders have a lot more work to do to develop a regional planning process that considers the joint needs of the region beyond reliability and market efficiency.

Weighing Costs versus Benefits

The various renewables-related technical studies in recent years have analyzed conceptually the level of transmission *needs* to allow renewables development in New England under various scenarios by the *amoun*t of capacity added (from 2,000 MW up to more than 12,000 MW), by *location* (only in New England, or with additional imports from Canada), and by *type* (onshore wind versus offshore wind).

While these studies have strengthened the coordination of regional planning efforts and helped identifying the tradeoffs above, they, however, do not provide the information needed to do a comprehensive cost-benefit analysis for major transmission expansions needed to support various levels of renewable resource development.

[37] New England Wind Integration Study, 2010, page 14.

Costs - One of the most critical issues is to develop clear specifications of transmission solutions to enable various levels of renewable penetration and understand the plausible range of costs associated with these transmission solutions. The cost figures estimated in the 2009 Governor's Study provide a good starting point, but they should be updated and tailored to specific transmission solutions considered in ISO-NE's planning process. For example, a 2011 report prepared for NESCOE provides detailed cost estimates for transmission needed to interconnect 3,000 MW of wind capacity in Maine and New Hampshire.[38]

Benefits - ISO-NE currently uses a narrowly-defined set of benefits metrics to evaluate transmission projects as a part of its planning process. The Economic Study includes customized metrics that are developed to analyze a given set of resource or load scenarios, but the benefits typically reflect only production cost savings and environmental emissions reductions. The EIPC Phase II report similarly considers only production cost savings to measure the economic benefits of various transmission scenarios. Limiting the scope of benefits considered at the planning stage makes it difficult to identify and compare transmission projects that would be needed to meet renewable targets and it can also result in premature rejection of valuable projects as they may not be justified based on production cost savings only.. In contrast, other RTOs such as MISO, SPP, and CAISO have expanded the types of benefits considered in their evaluations of transmission projects and portfolios in order to better inform the planning process.

At this juncture, the states and ISO-NE can no longer delay the necessary analyses to plan for the most cost-effective regional approach to meet the region's renewable energy targets.

Transmission Cost Allocation

Given the likely magnitude of transmission investments needed to integrate new renewables in New England, one major challenge is to decide who pays for these investments (e.g., split between generators vs. customers, allocation across customers in different states). FERC articulated the "beneficiary-pays" principle and required the cost allocation to be "at least roughly commensurate with estimated benefits" in its Order No. 1000. ISO—NE and its stakeholders engaged in a process of outlining new cost allocation procedures for intra-regional and inter-regional projects. In July 2013 ISO-NE filed compliance with inter-regional requirements. On the same day ISO-NE, NYISO and PJM filed a related revised Northeastern ISO/RTO Planning Coordination Protocol. The protocol is an inter-regional agreement among the three regions that describes the inter-regional planning process and inter-regional cost allocation methods. On November 15, 2013, ISO-NE made a compliance filing with FERC regarding Order No. 1000 intra-regional requirements. For intra-regional projects, ISO-NE proposes that cost allocation for projects with public policy need be done on 70/30 basis. 70% of costs is allocated region wide and 30% is allocated to states with an identified public need. The multi-state RTOs MISO and SPP have developed cost allocation procedures to remove the "who pays" roadblock, and these cost allocation procedures are part of a more integrated transmission planning process. In addition, CAISO has implemented the Location-Constrained Resource

Interconnection (LCRI) policy to encourage the growth of remote renewable energy resources, and resolved the “chicken-and-egg” problem of renewable generators not getting PPAs until they had transmission rights and also not being able to sign interconnection agreements until they had PPAs.

Lessons Learned from Other Regions

There are several valuable lessons that can be learned by reviewing the transmission planning process and cost allocation principles in other regions. Multi-state regions, such as MSIO and SPP, could provide richer lessons learned as they face similar challenges requiring a stronger coordination among states and sub-regions. On the other hand, single state ISOs (CAISO and ERCOT) are characterized by more straightforward planning and cost allocation processes as the needs of several diverse (but connected) states do not need to be balanced against each other.

One important lesson is the importance of analyzing a wide variety of benefits beyond traditional production cost savings and incorporating these benefits into the planning analyses, which would help with the identification valuable transmission projects and allow a better economic comparison of alternatives against each other.

As discussed in a recent Brattle Group report prepared for WIRES, the potential benefits that the transmission investments could provide in addition to traditional production cost savings include:[39]

- Additional production cost savings that are not captured in traditional production cost simulations (e.g., mitigation of congestion costs due to transmission outages, mitigation of extreme events and system contingencies)
- Reliability and resource adequacy benefits (e.g., avoided reliability projects, reduced planning reserve margins)
- Generation capacity cost savings (e.g., access to lower-cost generation resources)
- Market benefits (e.g., increased competition and liquidity)
- Environmental benefits (e.g., reduced emissions)
- Public policy benefits (e.g., reduced cost of meeting public policy goals such as RPS targets)
- Employment and economic development benefits
- Other project-specific benefits (e.g., storm hardening, increased load serving capability)

Midwest ISO (MISO)

[39] “The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments,” prepared by Brattle Group for WIRES, July 2013 (J. Pfeifenberger, J. Chang and M. Hagerty). Available at: http://wiresgroup.com/docs/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

MISO currently uses the Multi-Value Project (MVP) process within its annual Midwest ISO Transmission Expansion Plan (MTEP) to identify public policy projects that provide a wide variety of benefits, including meeting state renewable energy targets. This approach began with a regional planning study to meet growing RPS needs and was incorporated into MTEP planning with improved cost allocation methods.

The MTEP process has been in place in MISO for a decade now. In 2008 MISO conducted a Regional Generator Outlet Study (RGOS)[40] to identify and plan for regional transmission plans related to meeting Renewable Portfolio Standards. In addition to meeting RPS goals, RGOS identified plans that would also reduce the wholesale cost of energy, reduce congestion, and increase reliability. These projects later became the initial candidate portfolio for MISO's Multi-Value Project planning. To maximize wind resource benefits in the MVP process, in 2009 MISO coordinated with regulatory bodies, such as the Upper Midwest Transmission Development Initiative, to select low cost energy zones. So far, the MTEP process has led to a small number of MVP projects in 2010, a larger amount in 2011.[41]

Prior to the major expansion of wind projects in MISO, the costs of generator interconnection network upgrades were split 50/50 between the generator and transmission developer. This split was intended to incentivize the generator to locate in places that would minimize the potential transmission upgrade costs. This resulted in higher costs to zones near wind projects, even if they were not receiving the majority of the benefits of the projects. Midwest ISO member utilities eventually objected and threatened to leave MISO if new cost allocation was not developed. In 2010 MISO proposed and the FERC accepted cost allocation reforms. The MVP category was developed for projects supporting energy policy imperatives and postage stamp cost allocation for these projects was established.[42] In order to be considered an MVP the project must not only increase economic or reliability value but also generate total financially quantifiable benefits with a benefit-to-cost ratio of 1.0 or higher.

Postage stamp allocation for MVPs creates a uniform 100% regional allocation based on withdrawals, and costs are recovered from customers through a monthly energy usage charge. During development of this cost allocation method, MISO considered requiring generators to pay 20% of the costs for new MVP lines, but the provision was abandoned.[43] Other generation interconnection projects that do not qualify as an MVP project have cost allocated (depending on project size. Projects 345 kV and greater are allocated 90% to the interconnecting generator and the rest on a postage stamp basis. Projects less than 345 kV are allocated entirely to the generator. Additionally there is a provision allow for cost sharing among generators as a Shared Network Upgrade (SNU). In MISO's transmission planning and cost allocation filing, the FERC

40 "Regional Generator Outlet Study," MISO Website: https://www.misoenergy.org/Planning/Pages/RegionalGenerationOutletStudy.aspx.

41 "Multi Value Project Portfolio," MISO, January 10, 2012.

42 S. Fink, K. Porter, C. Mudd, and J. Rogers, "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations," National Renewable Energy Lab, February 2011.

43 "Midwest ISO Submits to FERC New Cost-Allocation Methodology for Transmission Projects," Troutman Sanders, 2010.

accepted this cost allocation and directed them to propose additional procedures related to public policy lines.[44]

The MTEP process directs MISO to identify projects needed to comply with applicable state and federal laws as well as applicable regulatory mandates and obligations.[45] To be approved as MVPs, they must meet regional public policy needs reliably and economically while providing multiple types of regional economic value to be approved as MVPs. Economic benefits considered include stability, wind generation enabled, production costs, robustness, operating reserves impact, planning reserve margin benefits, transmission line reductions, line losses, avoided capital investment, and economic stimulus effects associated with the wind turbine and transmission investments.[46] Qualitative and social benefits include generation flexibility, decreased natural gas risk, decreased wind generation volatility, job creation, and carbon reduction.

MISO based its resource location assumptions on the premise that it would reduce costs to choose balanced options, incorporating (1) some amount of transmission built out to the best wind source areas, and (2) the use of local wind resources that may yield lower capacity factors.[47]

Through RGOS and MVP portfolio analysis, MISO has identified a set of transmission solutions that will enable it to deliver the 41 million MWh of wind to meet the region's RPS, with benefit-to-cost ratios ranging between 1:8 and 3:0.[48] The variety of benefits MISO considers when analyzing MVPs is wide.[49] For instance, the 2011 MVP portfolio was estimated to provide $41 billion of increased market efficiency, $5 billion of deferred generation investment, $3 billion of benefit for efficient wind turbine siting and avoided transmission investment over the next 40 years.[50] The MVP portfolio provides significant benefits and since the major identification of projects in 2011.

Southwest Power Pool (SPP)

SPP currently uses its Integrated Transmission Planning (ITP) process to balance long-term transmission investment and congestion costs. The ITP process integrates the planning of transmission for interconnecting new generation, and needs driven by public policies. The planning process is iterative and includes both an *annual* assessment of needs and a *three-year* cycle of assessments of longer time horizons. In years 1 and 2, SPP studies a 10-year time horizon (ITP10); in years 2 and 3, SPP studies a 20-year time horizon (ITP20). SPP has noted

44 "Order On Compliance Filings And Tariff Revisions- 142 FERC ¶ 61,215," FERC, March 22, 2013.
45 "Midwest Independent Transmission System Operator, Inc.'s and MISO Transmission Owners' Compliance Filing for Order No. 1000, Regarding Regional Planning and Cost Allocation of Transmission Projects with Regional Benefits," Docket No. ER13-187-000, October 25, 2012.
46 "Multi Value Project Portfolio," MISO, January 10, 2012.
47 "Multi Value Project Analysis Report," MISO, January 10, 2012, p. 17.
48 "Multi Value Project Portfolio Results and Analyses," MISO, January 10, 2012, p. 1.
49 When analyzing both 20- and 40-year NPVs, MISO's MVP process also uses two discount rates: 3% to reflect a "societal" rate and 8.2% to reflect the allowed rates of return of transmission owners. Some stakeholders have advocated for use of this social discount rate because it has previously been used for public projects other sectors.
50 Testimony of Jennifer Curran in MISO Docket No. ER13-187-000.

that, in the past their transmission planning had simply reacted to the needs associated with the utilities. The current, more integrated, planning process allows them to better manage future scenarios such as renewable energy standards.[51]

In the ITP, public policy needs, such as renewable development, are included in the Priority Projects category to expedite approvals for projects. Recently, SPP analyzed two scenarios for transmission development to support wind penetration- one for 7 GW and another for 11 GW. These scenarios were selected based on the assumption that 11 GW would be needed to meet RPS goals and would ultimately be approved as priority projects. In the first round of analysis SPP reviewed a wide variety of both economic and societal benefits including adjusted production cost, loss impacts, reliability, and environmental impacts before narrowing the transmission projects down to 6 that supported 7 GW or a 10% level of wind.[52]

A second phase of analysis focused on quantifiable benefits such as adjusted production costs, reliability, wind benefit, and fuel diversity and losses. "Wind benefit" was quantified by revenues paid to wind developers, an element new to SPP's assessment of transmission benefits. SPP assumed that the benefit from wind is tied to the incremental additional energy output from wind resources so it quantifies this benefit as wind additions multiplied by a Locational Imbalance Price. SPP's report analyzed the price and amount of wind dispatched to indicate whether fewer curtailments occurred.[53] The final projects selected are estimated to provide $3.7 billion in benefits to the SPP over 40 years and cost just $1.14 million. Benefits will stem from reduced congestion on the power lines, better integration of east and west regions, and new renewable and non-renewable generation to the electric grid.[54]

ITP allocates transmission costs using a "Highway/Byway" methodology that determines allocation by voltage. This method is designed to allocate costs roughly commensurate with the level of benefits, and to identify which projects are used on a regional and zonal basis. A regional postage stamp rate is used for projects with voltage greater than 300 kV. Projects with voltages between 100 and 300 kV have 33% regional and 67% zonal cost assignments. For projects with voltages less than 100 kV, a zonal allocation is used. Conversely, cost allocation for projects specifically used to integrate new wind is slightly different, with projects above 300 kV being allocated regionally, but 100 - 300 kV costs allocated 67% regionally and 33% zonally.[55] SPP ITP also includes a "Regional Cost Allocation Review" of Highway/Byway transmission cost allocation by the Regional Allocation Review Task Force (RARTF). Through this review, SPP can retroactively assess adjusted production costs, positive impact on capacity required for losses, improvements in reliability, reduction of emission rates, reduced operating reserves, improved import/export limits, and public policy benefits. Work by the Metrics Task Force has improved and expanded the range of benefits quantified and measured with additions

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51 "SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits," South West Power Pool Press Release, April 27, 2010.
52 "SPP Priority Projects Phase II Report," South West Power Pool, February 1, 2010.
53 "SPP Priority Projects Phase II Report," South West Power Pool, February 1, 2010, p. 30.
54 "SPP Approves Construction of New Electric Transmission Infrastructure To Bring $3.7 Billion in Regional Benefits," South West Power Pool Press Release, April 27, 2010.
55 S. Fink, K. Porter, C. Mudd, and J. Rogers, "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations," National Renewable Energy Lab, February 2011.

such as Reduced Loss of Load Probability (LOLP) or the benefits from meeting public policy goals.[56]

For new generator connections, costs are allocated regionally if the generator is a network resource. To ensure generator interconnection network upgrades for wind resources were also eligible for regional cost recovery, SPP has made revisions to its Safe Harbor calculation. One of the requirements to be considered a network resource is SPP's Safe Harbor Cost Limit, calculated as a threshold of $180,000 per MW times either the planned maximum net dependable generating capacity of the project or the requested transmission capacity of the resource designation. Due to wind's variable output, SPP previously assigned a net dependable capacity value to wind equal to 10% of their nameplate capacity. This led to the level of network upgrade costs that were eligible for regional cost recovery being much lower for wind projects, which resulted in the zones hosting wind power projects bearing more of the transmission costs. On June 18, 2009, FERC approved an SPP tariff revision modifying the Safe Harbor Limit policy so that the requested transmission capacity for SPP's wind resources instead of the net dependable capacity will always be applied when calculating the limit for wind projects.

The Electric Reliability Council of Texas (ERCOT)

In Texas all transmission analysis and planning is handled by ERCOT, who undertakes a system-wide assessment of needed reliability and economic projects and coordinates regional planning. A Regional Planning Group (RPG) made up of stakeholders and market participants are able to provide feedback on potential transmission projects and suggest additional projects. Both reliability and economic projects are subject to postage-stamp cost allocation. Transmission needs are identified and studied in ERCOT's Five-Year Transmission Plan in addition to the biannual Regional Transmission Plan and Long-Term System Assessment (LTSA). The Five-Year plan addresses reliability and economic transmission needs and recommends specific planned improvements. The LTSA reviews a 20 year period and informs long term planning without identifying specific solutions. Lastly, ERCOT also performs frequent, non-public stability studies to assess voltage and frequency response issues on the grid.[57]

ERCOT's Competitive Renewables Energy Zones (CREZ) plan has become one of the best known ISO/RTO solutions to the chicken versus egg dilemma when rapid transmission is needed for renewables has been the success of. Established in 2005 through a Texas Senate Bill, the development of CREZ was designed to ensure cost-effective transmission lines where built to transport new renewable power related to the Texas RPS. As wind energy resources began rapidly expanding in Texas, it became clear that transmission development was needed to connect new resources as annual congestion costs on the Texas grid reached $400 million by 2006.[58]

56 "Benefits for the 2013 Regional Cost Allocation Review," Southwest Power Pool, September, 13 2012.
57 "2012 Electric System Constraints and Needs," ERCOT, December 28, 2012, p. 2.
58 Mark Dreyfus, "Texas CREZ Policy and Transmission Expansion Update," Austin Texas, December 2, 2010, Slide 3.

The CREZ program identified areas where transmission was needed by examining both existing and expected generation.[59] It also used a competitive bid solicitation process to assign the projects and allow both incumbent and non-incumbent utilities to win the rights to build, own and operate them.[60] Almost 3,600 miles of transmission are now planned or under development.[61] The final CREZ lines are projected to be complete and energized this year. Studies indicate the new lines should remove West-to-North stability limits as a transmission constraint.[62] In order to ensure transmission was built ahead of renewables, the ERCOT CREZ method requires transmission owners bear the upfront costs of development and recover them through rates spread across all of ERCOT, regardless of project benefits.[63]

Even with this success, wind development in Texas continues to growth rapid and may require additional transmission development. ERCOT currently has 10 GW of wind installed and as of November 2012, ERCOT reported approximately 20,000 MW of new wind generation projects under study, most in the advanced stage of study. [64]

Long term studies indicate continued expansion of wind resources in the already constrained "Panhandle" grid. With minimal local load, this area of the grid is experiencing voltage stability and grid strength challenges.[65] There are currently 3.4 GW of wind capacity in the Panhandle and an additional 7.7 GW may come online. To plan for these needs ERCOT has undertaken a second study of renewable energy zones the Panhandle Renewable Energy Zones (PREZ) Study, which should be completed by January 2014.[66]

As an ISO not connected with the rest of the U.S. grid, ERCOT is not under the jurisdiction of the FERC and therefore not required to comply with any of the FERC 1000 requirements aimed at improving transmission planning for public policy projects for other areas. Future transmission planning may continue under the current planning scheme, supplemented with CREZ study.

California ISO (CAISO)

Over the past several years, CAISO had several reforms in place regarding its planning and cost recovery processes.

In 2007, CAISO initiated the Location-Constrained Resource Interconnection (LCRI) policy to encourage growth of renewable resources. This allowed renewable integration lines that are not network facilities (e.g., Tehachapi) to be initially paid by customers through postage-stamp rates

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59 Michael Giberson, "Texas regulators choose companies to build transmission to reach wind power," The Know, January 30, 2009.
60 Christopher D. Underwood, et al. "Competitive Bid Solicitation for Transmission Projects: A Rising Trend Among Independent System Operators and Regional Transmission Organizations," Burns and McDonnell, July 9, 2012, p.1.
61 "Competitive Renewable Energy Zone Program Oversight- CREZ Progress Report No. 10," Prepared by RS&H for the Public Utility Commission of Texas, January 2013, P, 6.
62 "ERCOT Report on Existing and Potential Electric System Constraints and Needs," ERCOT, December 2012.
63 Texas PUC Order, Docket No. 33672.August 15, 2008.
64 "2012 Electric System Constraints and Needs," ERCOT, December 28, 2012, p. 2.
65 Trip Dogget, "ERCOT – A Strategic View of the Future," ERCOT, presented to the GCPA Fall Annual Conference, October 2, 2013.
66 Shun-Hsien (Fred) Huang, "Panhandle Renewable Energy Zone Study," ERCOT, March 26, 2013.

and the interconnecting generators to be charged later on a "pro rata" basis as they become online. This resolved the "chicken-and-egg" problem of renewable generators not getting PPAs until they had transmission access and also not being able to sign interconnection agreements until they had a PPA.

In 2010, CAISO revised its tariff to consider transmission planning on a state-wide basis (as opposed to project-by-project) and increase competitive opportunities. Specifically, it added the development of "Conceptual Statewide Transmission Plan" as an initial step of its planning cycle to recognize policy mandates such as RPS and coordinate regional and sub-regional planning processes in California (not just CAISO).

In 2010, CAISO signed a memorandum of understanding to coordinate its transmission planning efforts with CPUC's transmission permitting and long-term generation procurement processes (LTPP). Accordingly, CAISO agreed to incorporate the renewable generation scenarios that CPUC develops in its transmission planning analysis, and CPUC agreed to give substantial weight in its siting and permitting process to projects that are recommended by CAISO. The overall goal was to ensure that the transmission planning process includes the analyses necessary later in the permitting phase.

CAISO's Transmission Planning Process (TPP) consists of 3 phases, covering approximately a 2-year period (on a rolling basis) and categorizes transmission projects as reliability-, economic-, and public policy-driven.

- In Phase 1, CAISO works with state agencies and stakeholders to develop base case assumptions and the study plan in an open stakeholder process and initiate the Conceptual Statewide Transmission Plan which lays out the renewable generation scenarios to be analyzed.
- In Phase 2, CAISO conducts the technical studies and develops a comprehensive transmission plan. It starts with the reliability studies to identify upgrades or additions that would be needed to ensure system reliability. It then analyzes the power flows, system stability, generation deliverability, and production costs under the renewable generation scenarios to identify additional transmission needs. CAISO identifies the "least regret" transmission projects needed in most scenarios and recommends them for the Board approval. The upgrades and additions needed in the base case but not in other scenarios are carried in the next planning cycle for further evaluation.

  CAISO's "least-regrets" approach helps balancing the region's transmission needs to support the 33% RPS targets while reducing the risk of stranded investments that could occur if the transmission and renewables build-out are out of sync.
- In Phase 3, CAISO solicits proposals to finance, construct, and own projects that are eligible for competitive procurement. Under the current FERC-approved tariff, the economic- and public policy driven projects, and also reliability projects that provide additional public policy or economic benefits are eligible for competitive solicitation (except for upgrades to existing facilities).

Costs of transmission projects are recovered through transmission access charges (TAC) that apply to all types of projects (reliability, economic, and public policy). The regional, highvoltage projects are paid uniformly by all loads on a postage-stamp basis. On the other hand, the local, low-voltage projects are paid on a utility-specific license-plate basis.

CAISO believes that it has identified most of the transmission projects needed to meet 33% RPS target through the previous cycles. It found no additional public policy projects in its 2012-2013 Plan and only a couple small projects in the most recent 2013-2014 Plan.

Non-RTO Areas

In 2009 two projects in a Non-RTO solved the chicken and the egg problem by allowing wind developers to sign up ‘‘anchor tenants’’ for line capacity well in advance of construction and at negotiated rates. These examples, Chinook and Zephyr Power (ER09-432-000 and ER09-433-000), sold half their line capacity to wind farms at negotiated rates. The second half of each project was to be put out to an open season bid.[67] While Chinook has since been suspended, the open season on the Zephyr project was a success with its full capacity under contract.

[67] Hannes Pfeifenberger and Peter Fox-Penner, “The Anchor-Tenant Model – And Some of the Chickens and Eggs,” The Electricity Journal, July 2009.