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F. PROJECT BACKGROUND AND NEED

F.1 PROJECT PURPOSE AND OVERVIEW

F.1.1 Background[1]

New England's transmission system was built over several decades by regulated utilities that were vertically integrated – that is, they planned, owned and operated electric generation, transmission, and distribution facilities. Interconnections between adjoining utilities and neighboring regions existed and were used to maintain reliability and to share excess generation. However, the utilities were not required to allow other utilities to transport electricity over their transmission systems.

Accordingly, each electric utility planned, built and operated generating facilities and transmission infrastructure to complement each other within a single service territory. Moreover, electricity was viewed as a "bundled service" and not as a market commodity subject to trading over the transmission infrastructure. Regulators in each state approved generation and transmission infrastructure and set rates.

During the 1960s, New England's electric utilities, including CL&P, developed a long-term plan for a transmission grid that initially centered on integrating the dispatch of electricity from eleven strategically located large generating stations that could deliver large blocks of power to loads within and between the New England states. The plan was called the "BIG 11 POWERLOOP," and provided the "backbone" of an integrated New England electric utility system, extending from central Maine to south-central Connecticut.

The Northeast Blackout of 1965 highlighted the need for such operational coordination between the region's utility companies, and also prompted creation of the Northeast Power Coordinating Council

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[1] This discussion is taken in large part from "Electricity Transmission Infrastructure Development in New England," Polestar Communications & Strategic Analysis, Dec. 2007

(NPCC) in January, 1966. NPCC was a voluntary international electric Regional Reliability Council formed by the utilities in the six New England States, Ontario, Quebec, and the Maritime Provinces of Canada. NPCC established a number of fundamental criteria documents that define the planning, design and operating principles that each participant electric utility company must follow to assure a reliable interconnected power system.

In June, 1968 the North American Electric Reliability Council (NERC) was formed and thereafter established voluntary reliability and operating performance standards for the electric power grid in North America.[2]

In 1971, the New England utilities formed the New England Power Pool (NEPOOL) as a voluntary organization to direct the minute-to-minute operation of the region's power grid to match supply and demand reliably and economically as well as to institute planning and operating reliability standards and requirements.

Restructuring

The electricity industry began undergoing a substantial change when the Energy Policy Act of 1992 created open transmission access by mandating that all utilities allow other generators the use of their lines. Then, in 1996, Federal Energy Regulatory Commission (FERC), by its Orders 888 and 889, further encouraged competition in the wholesale power market by requiring owners of transmission facilities to provide access on request and on a fair and nondiscriminatory basis.

Within a decade, every state in New England except Vermont enacted legislation to "restructure" retail electricity markets. Under restructuring, most public utilities were either required or strongly encouraged to sell their generating plants to companies that would operate them in a competitive marketplace. (Utilities remained regulated and responsible for transmission and local distribution service.) Regulatory

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[2] On January 1, 2007, NERC became the North American Reliability Corporation.

jurisdiction over transmission was split between the FERC, with rate setting authority, and state agencies, with responsibility for siting new infrastructure. Restructuring also profoundly changed the operational demands and management requirements of the electric power grid – as the “patch work” system had to function seamlessly across the region as well as with other regions.

Independent System Operators (ISO)

Independent System Operators (ISOs) were created under FERC oversight to implement and administer the competitive, wholesale marketplace to ensure fair and open access as well as reliable operation of the region’s transmission system. In 1997, NEPOOL transferred the day-to-day operation and management of the New England bulk transmission system and generation facilities to ISO New England (ISO-NE). ISO-NE is a not-for-profit corporation that is responsible for operating New England’s bulk-power generation and transmission system, overseeing and administering the region’s wholesale electricity markets, and managing the regional bulk-power-system planning process.

On February 1, 2005 – after a four-year development effort – FERC approved ISO-NE’s designation as a Regional Transmission Organization (RTO). As an RTO, ISO-NE assumed broader authority for the day-to-day management of the region’s transmission system and a greater level of independence to effectively administer the competitive wholesale market. ISO-NE has also been granted authority to conduct regional planning and to direct transmission owners to operate their facilities in a manner that maintains system reliability – including the requirement to upgrade existing transmission lines or build new ones to assure reliability.

Reliability Organizations

The August 2003 Eastern Electricity Blackout – involving portions of the mid-west, northeast and the Canadian Province of Ontario – affected 50 million people and emphasized that electric power grids (which have become increasingly interconnected as a result of technology and restructuring) are only as strong as their weakest links. The blackout prompted federal legislation to make NERC's voluntary reliability criteria mandatory and enforceable.

The Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" (ERO) to develop and enforce these standards. In 2006, FERC approved NERC as that organization. NERC is supervised by FERC and by Canadian governmental authorities. Its criteria relate to the planning and operation of the bulk electricity system and cover areas such as: balancing consumer demand with generation supplies, emergency operations, cyber security, vegetation management, and disturbance reporting. As of June 2007, U.S. utilities and other bulk electricity industry participants that violate reliability criteria requirements will face enforcement actions and fines of up to $1 million per day.

Resource Adequacy and System Security

NERC's definition of reliability encompasses two concepts: adequacy and security. Adequacy is defined as the "ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times" while security is defined as "the ability of the system to withstand sudden disturbances". Adequacy implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingencies; security implies that the system will remain intact and stable even after planned or unplanned transmission facility outages, equipment failures, the loss or unavailability of generation resources.

The provision of resource adequacy within a service territory is no longer within the control of regulated public utilities. Since restructuring, generation has been developed primarily by private entrepreneurs, and the location of the new plants within the region has been influenced by factors other than the location of load pockets, which include: site availability/costs, availability of fuel (typically natural gas), proximity of large bodies of water for cooling, and the cost of local labor.

For instance, Maine has the lowest construction labor rates and land costs in the region, and has sufficient access to fuel (natural gas). As a result, substantial new generating capacity has been built in Maine and therefore located up to hundreds of miles from the “load centers” of Massachusetts and Connecticut. Because the construction of north-south transmission capacity has lagged market development, electric capacity sometimes becomes “bottled up” in Maine during peak periods and cannot be sent to where it is demanded. Therefore, from a regional reliability standpoint, some generating plants are not optimally located.

ISO-NE and state regulators and legislatures have accordingly instituted various policy initiatives designed to encourage the construction of new generation and the deployment of new demand-reduction strategies where they will best contribute to local and regional resource adequacy. Early indications are that these initiatives will result in the addition of substantial new generating capacity. However, the extent of this new capacity – and the extent to which the new entries may cause the retirement of older, less efficient, and more environmentally challenged units - is not yet clear. In the meantime, the regulated providers of transmission services (Transmission Owners, or TOs), such as CL&P and WMECO, are obliged by binding tariff provisions to design and propose transmission improvements that will assure that the bulk power supply system complies with applicable mandatory reliability standards.[3]

Contingency Planning

A key element of these reliability criteria is the consideration of “contingency” events wherein critical generation and/or transmission facilities are assumed to trip out of service or be unavailable. A “contingency” is an unintentional event, usually involving the loss of one or more system elements, which affects the power system.

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[3] NERC’s “Reliability Standards for the Bulk Electric Systems of North America”; the NPCC’s “Basic Criteria for Design and Operation Of Interconnected Power Systems,” Document A-02 (revised May 6, 2004); the NPCC’s "Bulk Power System Protection Criteria,” Document A-05 (revised January 30, 2006); ISO-NE Planning Procedure No. 3, “Reliability Standards for the New England Area Bulk Power Supply System” (effective date October 13, 2006); ISO-NE Planning Procedure No. 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Applications Analysis”; and the “Transmission Planning Guideline” for Northeast Utilities.

If a generating unit or a transmission line is removed from service, increased power flows must immediately be carried on transmission lines that remain in service. Thus, transmission capacity for an area must be designed not only to transmit the imported power required to offset anticipated generating deficits under normal conditions, but also to transmit that imported power reliably following specific contingencies that the system is required to withstand. Otherwise, line flows could exceed emergency transmission line ratings and force the utility to disrupt service to large blocks of customers to prevent permanent damage to the electric system and an uncontrolled loss of additional load.

To evaluate compliance with applicable reliability criteria, planning contingencies are simulated on computer models developed to represent actual and future system conditions. If the simulation shows that transmission lines will overload and/or voltage will not be maintained within acceptable limits under one or more of the contingencies for which the system must be designed, corrective action must be implemented in order to maintain the reliability of the electric grid.

The applicable planning criteria require that the transmission system have sufficient capacity “to integrate all resources and serve area loads” both when all system elements are available and in the event of the loss of a critical generator, transmission circuit, transformer, or certain other specified elements. Moreover, once one of those critical elements is lost from service, the system must be capable of being adjusted within 30 minutes, such that it will continue to operate reliably in the event of a second contingency. Planners use the terms “N-1” and “N-1-1” to designate the contingency conditions in which the system must be capable of reliable operation. N-1 designates the state of the transmission system following the occurrence of a contingency. N-1-1 designates the condition of the system following the occurrence of a contingency, assuming that one element is already out of service.

Unplanned outages of generating units are common in the electric industry. For example, when ISO-NE set a record for peak winter load on January 21, 2003, eight generating units in SWCT, with a total capacity of approximately 1,038 MWs, were unavailable due to problems associated with the extremely cold weather. And for over 12 hours on June 30, 2008, Milford Power Units 1 and 2 tripped off line during a three-day-long forced outage of Millstone Unit 2, making about 1,470 MWs of Connecticut-based generation unavailable on a summer day. In 1996, Connecticut suffered the unplanned loss of 3,200 MWs of nuclear generating capacity, some of it permanently.[4]

Transmission line outages also occur. For example, in November 2002, the Norwalk Harbor – Northport, New York submarine cable system went out of service as a result of damage caused by a boat anchor. The cable system was out of service until June, 2003. (The length of this outage reflects the difficulty of diagnosing and repairing damage in submarine and underground transmission systems. Forced outages of overhead transmission lines are typically much shorter – often measured in hours and rarely more than a few days.)

The reliability criteria seek to assure that the transmission system will survive contingencies even if they occur when the system is serving peak loads and is under stress. Accordingly, the computer modeling of system performance must require the integrated system to serve loads that are forecasted by ISO-NE to occur in the future, including peak loads that would be expected only in the event of extreme weather; to accommodate intra-regional power transfers; and to operate while "reasonably stressed" by the unavailability of generation proximate to concentrations of load. Requiring the transmission system to operate effectively under the stress caused by the unavailability of multiple generating units recognizes that units may be unavailable at any time for many reasons – such as economics, equipment failure, fuel supply and maintenance. Also, environmental restrictions on fossil-fueled generating stations in

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[4] The three units of Millstone Nuclear Power Station, totaling 2,668 MWs in capacity were shut down by the Nuclear Regulatory Commission in early 1996. The 591-MW Connecticut Yankee Atomic Plant closed for scheduled refueling in December, 1996 but never re-opened. Millstone Unir 1, a 650-MW unit, also never returned to operation and was retired in 1998. Millstone Unit 3 was returned to service in July, 1998 and Millstone Unit 2 in May, 1999.

Connecticut could affect continuous operation of certain generating units or result in their permanent closure.

The bulk-power supply system is not only planned, but is also operated, so that it can withstand the unplanned loss of system elements. Thus, most transmission lines typically carry currents that are a fraction of those that they could safely carry. Each transmission line is thus available to accept additional current that would instantaneously flow onto it in the event of the sudden loss of other system elements.

F.1.2 The SNETR Study

The Southern New England Transmission Reliability (SNETR) Study is the collective name for coordinated series of studies of the deficiencies in the Southern New England electric supply system, which began in 2004. Both the SNETR study and the NEEWS Plan were developed by ISO-NE, and by the planning staffs of NUSCO and National Grid, with the assistance of outside consultants, working together in a “working group” established by ISO-NE. Membership in the working group was open to all New England Transmission Owners.

When the SNETR study effort was undertaken, several major Southern New England transmission projects were in the process of being approved or were under construction, and were expected to be in service by 2009. The working group undertook a study of further improvements that would be needed thereafter to address transmission system problems expected to arise through 2016, assuming the completion of the projects already underway and projected peak-load growth. Initially, these studies considered limitations on east-west power transfers across Southern New England and transfers between Connecticut and southeast Massachusetts and Rhode Island.[5] These limitations had been identified as interdependent (that is, as affecting one another) in ISO’s 2003 Regional Transmission Expansion Plan (RTEP03). In the course of studying these interstate power-transfer limitations, the ISO working group

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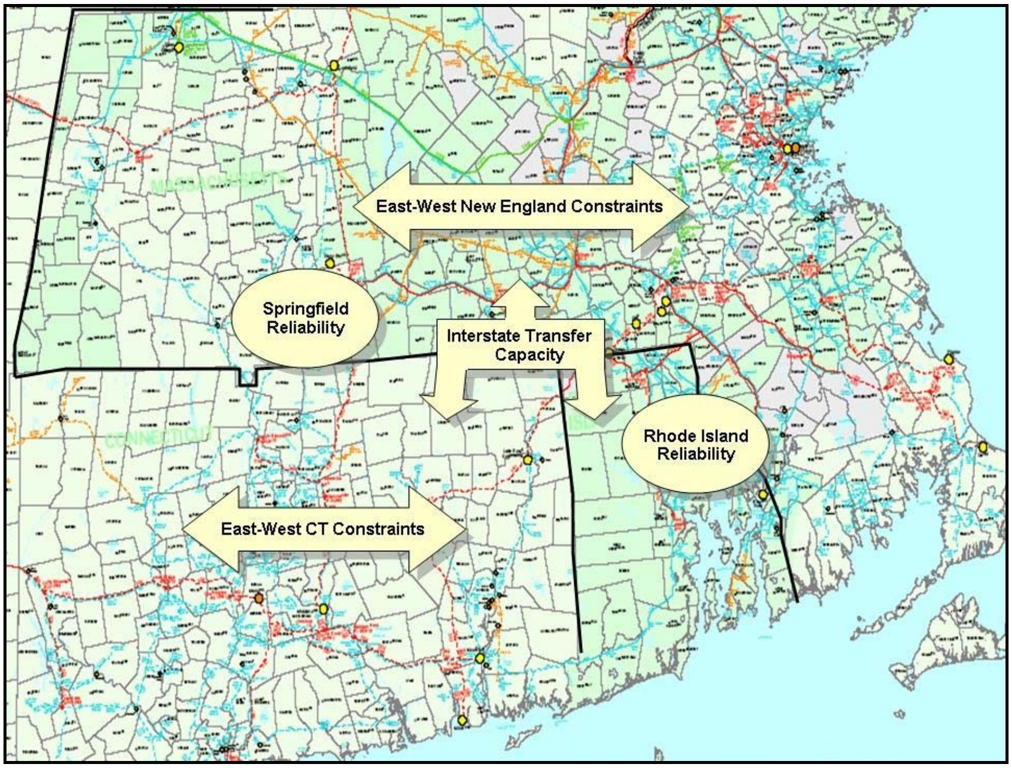
[5] These studies also included issues in the Boston and southeastern Massachusetts areas, which are outside the scope of the NEEWS Plan.

determined that previously identified reliability problems in Greater Springfield and Rhode Island were not simply local issues, but also affected interstate transfer capabilities. In addition, the planners identified constraints in transferring power generated in – or imported into – eastern Connecticut across central Connecticut to the concentrated load in SWCT. These inter-related problems with the Southern New England transmission system are illustrated in Figure F-1.

Figure F-1: Reliability Concerns in the Southern New England Region



A comprehensive plan to address all of these interrelated problems was then developed, at first under the name of the Southern New England Transmission Reliability Plan, and later under the more descriptive project umbrella name of the New England East West Solution. The end result of these processes was the identification of a long range plan comprising four separate projects designed to work together to provide needed improvements in the Southern New England transmission system.

F.1.3 The NEEWS Plan

The five deficiencies illustrated in Figure F-1 are addressed by a combination of four separate NEEWS projects and certain ancillary improvements, such as the Manchester to Meekville Junction Circuit Separation Project **(**MMP). Each project provides needed reliability improvements in its own right, but all are designed to work together to relieve transmission constraints and provide reliable transmission of electric power within and across New England under both normal conditions and following contingency events such as the unplanned outage of one or more transmission lines or generating plants. In general terms, the four NEEWS projects are:

- **The Greater Springfield Reliability Project (GSRP)**, which includes: the construction of a new 345-kV line along approximately 35 miles of overhead line ROW (23 miles in Massachusetts and 12 miles in Connecticut); the construction, reconstruction, and upgrade of 115-kV lines along approximately 27 miles of existing and expanded overhead line ROW in Massachusetts, and related substation improvements in both Massachusetts and Connecticut. In Massachusetts, a new 345-kV switchyard and two new 345-kV to 115-kV, 600-Megavolt Ampere (MVA) autotransformers in the Agawam Substation. In Connecticut, the required substation improvements associated with the new 345-kV line would consist of installing a 345-kV switchyard and a 345-kV to 115-kV, 600-MVA autotransformer in the North Bloomfield Substation. In addition, three 115-kV tie-lines at the North Bloomfield Substation are disconnected from Massachusetts. The **Manchester to Meekville Junction Circuit Separation Project (MMP),** involving the separation of two lines now on common transmission structures along two miles of ROW in Connecticut, has been developed to complement the GSRP.
- **The Interstate Reliability Project (IRP)**, which includes the construction of a new 345-kV line from National Grid's Millbury Switching Station in Massachusetts to its West Farnum Substation in North Smithfield, Rhode Island, to CL&P's Lake Road Substation in Killingly, Connecticut, and to CL&P's Card Street Substation in Lebanon, Connecticut. Overall, the project would

involve approximately 76 miles of new 345-kV lines, including approximately 16 miles in Massachusetts, 22 miles in Rhode Island, and 38 miles in Connecticut, together with related improvements to existing 345-kV and 115-kV facilities.

- **The Central Connecticut Reliability Project (CCRP)**, which includes the construction of a new 345-kV line from CL&P's North Bloomfield Substation to its Frost Bridge Substation in Watertown, a distance of approximately 38 miles, together with related improvements to existing 345-kV and 115-kV facilities.
- **The Rhode Island Reliability Project**, which, as proposed by National Grid, would consist of an approximately 21-mile 345-kV line between its West Farnum Substation in North Smithfield, Rhode Island and its Kent County Substation in Warwick, Rhode Island, together with related improvements to existing 115-kV and 345-kV facilities.

The problems illustrated in Figure F-1 will be addressed by these four NEEWS projects as follows:

- **Regional East – West Power Flows.** Regional east-west power flows across New England are limited due to the potential overloading of existing 345-kV lines that traverse southern Massachusetts from east to west and potential voltage violations at substations served by those lines. Construction of the Interstate Reliability Project, the Central Connecticut Reliability Project, and the Greater Springfield Reliability Project will provide another path for power flowing from east to west, and will allow higher flows in these directions.
- **Connecticut Import Limitations.** Power transfers into Connecticut are limited and will eventually result in the inability to serve load under many contingencies that the system must withstand in order to comply with national and regional reliability standards. The construction of additional 345-kV ties to Rhode Island and Massachusetts will greatly improve the system's ability to serve the load by providing additional paths on which power may flow in the event of a planned or unplanned loss of a system element, such as a transmission line or generating unit, and

thus significantly increase power transfer limits into and out of Connecticut. In addition to improving the security of supply, this increase in import capacity will also yield economic benefits to Connecticut consumers by providing access to lower cost remote sources of power to the north; and is likely to provide environmental and statutory compliance benefits by enabling access to remote renewable and/or low emission power-supply sources.

- **Connecticut East-West Transfers.** Load in Connecticut is heavily concentrated in the southwest quadrant of the state (SWCT), whereas many of Connecticut's generation resources are located in the eastern part of the state. The anticipated completion of a 345-kV loop serving SWCT in 2009 will enable power to move freely through SWCT, and the construction of the Interstate Reliability Project and the GSRP will enable the import of sufficient power to provide more reliable service to the entire state, including SWCT. However, the increased power flows across central Connecticut necessary to serve the growing SWCT load will result in overloads on existing transmission lines following contingency conditions on the transmission system. This "bottleneck" between eastern Connecticut and the SWCT Loop will be eliminated by the addition of another 345-kV connection between these subareas. Providing a less constricted path to SWCT for power generated in eastern Connecticut and imported from central/eastern Massachusetts and Rhode Island will also reduce the amount of power forced to flow through the Springfield 115-kV system.
- **Rhode Island Reliability.** Transmission system reliability and dependence on local generation are the major concerns for the Rhode Island system. System modeling has demonstrated that a number of overload and voltage violations can occur on the Rhode Island transmission facilities following contingency conditions. These problems are caused by a number of contributing factors, both independently and in combination, including: high load growth (especially in southwestern Rhode Island and the coastal communities), generating unit availability, and transmission outages (planned or unplanned). The addition of the new 345-kV line from West Farnum Substation to Kent County Substation and other associated improvements will both

greatly improve the reliability of the state's transmission system and reduce dependence on local generation. The new 345-kV lines from the Millbury Switching Station to West Farnum Substation and from West Farnum Substation to Lake Road Substation would serve a dual role of both improving Rhode Island Reliability and providing an essential component of the new 345-kV Interstate Reliability Project, discussed above.

- **Greater Springfield Reliability.** The Greater Springfield reliability problems and their proposed solution are described above and in detail later on in this document.

The new transmission system connections that would be provided by the four projects together comprise the NEEWS plan and are illustrated in Figure F-2:

Figure F-2: NEEWS Project Elements

F.1.4 Documentation of the Need for the NEEWS Plan and the Greater Springfield Reliability Project

The need for the GSRP, and that for the other NEEWS projects, was described in a report first issued in draft by ISO-NE in 2006 and ultimately published (in both complete form available to qualified ISO-NE participants and in redacted form available to the public) as Southern New England Transmission

Reliability Report – Needs Analysis, January 2008 (Needs Analysis). In the “public” version of the report, certain “Critical Energy Infrastructure Information” (CEII) has been redacted, in order to comply with FERC and ISO-NE security policies[6]. A copy has been filed as part of Volume 5 of this Application.

Having identified the interrelated needs in the Southern New England Region, the ISO-NE working group turned to an analysis of transmission solutions – or “Options” that would address those needs. This part of the coordinated planning effort continued through 2006 and 2007, and included several presentations to the interested stakeholders at meetings of the ISO-NE Planning Advisory Committee (PAC). In April, 2008, ISO-NE posted for comment on its website a final draft of a document that had been developed over that period, which describes a set of “Options” for each component of the NEEWS Plan, entitled New England East-West Solutions (Formerly Southern New England Transmission Reliability) Report 2, Options Analysis, (the Options Analysis). That document has also been since published. A copy of the redacted public version of the Options Analysis is included in Volume 5 of this Application.

NUSCO then evaluated the “Options” identified by the Options Analysis for the Greater Springfield Reliability Project, and determined that the proposed project would provide the most system benefit, at the least cost, and with the fewest environmental effects. That decision process is described in a third report, entitled Northeast Utilities Solution Report for the Springfield Area, July, 2008. A copy of that report is also included in Volume 5 of this Application.

In 2007, ISO-NE included the NEEWS projects in its Transmission Projects Listing, and in 2008, it issued a technical approval for the projects pursuant to section I.3.9 of Attachment K to its Open Access

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[6] CEII refers to information vital to the Bulk Power System that, if utilized by someone wishing to do harm, could be critical data providing sufficient detail to enable the disabling of the Bulk Power System. It includes detailed drawings and descriptions of specific weaknesses and vulnerabilities of the transmission system. Parties and intervenors who wish to have access to the CEII material redacted from the Needs Analysis or from the Options Analysis discussed below, should contact ISO-NE Customer Service at (413) 540-4330 for information on how to apply for such access.

Transmission Tariff (OATT).[7] These steps represent ISO-NE's recognition that transmission system reliability need exists, that the GSRP (and the other NEEWS projects) have been proposed to meet that need, and that the projects will not have an adverse impact on the integrated transmission system. Until the market responds by developing credible alternative generation projects, demand-side projects, or merchant transmission facilities, and causes ISO-NE to drop the NEEWS projects from the Listing, CL&P and WMECO have an obligation to develop a backstop transmission plan in order to satisfy that reliability need. (Sec. 8, Attachment K, OATT). That duty is subject to receipt of all ISO-NE technical approvals and other normal permit and licensing requirements.

Although it is designed to work efficiently with the other NEEWS projects, the GSRP stands on its own as fulfilling urgent reliability needs in Greater Springfield and north-central Connecticut. It is needed and will "work" whether all, some, or none of the other NEEWS projects are built. While all of the NEEWS projects have been designed to complement, and not to conflict with one another, the GSRP can stand on its own. To demonstrate this existing and independent need, NUSCO planners have performed extensive new power-flow studies of the Greater Springfield and north central Connecticut area, taking into account updated load forecasts and relevant changes in the electric supply system. These studies examine the need for, and the benefits of, the GSRP without regard to the other NEEWS projects. The results of those studies are presented generally in this section and in detail in a "CEII Appendix" to this Section F[8].

F.2 THE NEW ENGLAND BULK-POWER SUPPLY SYSTEM

The New England bulk-power supply system is integrated and uses regional generating resources to serve regional load (i.e., the demand for electricity measured in MW) independent of state boundaries. Most of

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[7] FERC Electric Tariff No. 3, Sec. 3.6(c), Attachment K.

[8] Pursuant to FERC, ISO-NE and NUSCO CEII policies and procedures, CEII can not be publicly disclosed without restrictions. Accordingly, while CL&P may disclose the assumptions of its load flow studies, it may not disclose detailed results that identify specific weaknesses or vulnerabilities in the Bulk Power System. CL&P anticipates that the Council, its staff, parties and intervenors to the proceedings on this Application, and their counsel and expert consultants, will be able to obtain access to this CEII Appendix by executing a Non-Disclosure Agreement, pursuant to a Protective Order for which CL&P will apply shortly after its application is filed.

the transmission lines are relatively short and networked as a grid. Therefore, the electrical performance in one part of the system affects other areas of the system.

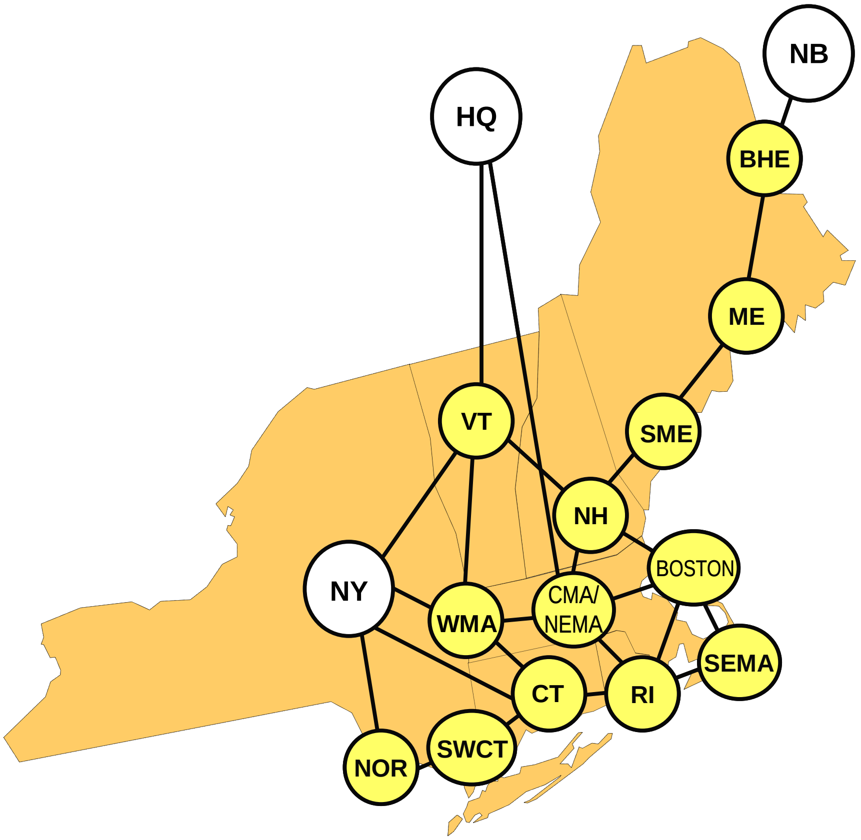
The New England regional electric system serves 14 million people living in a 68,000 square-mile area. More than 350 generating units produce electricity, representing approximately 31,000 MWs of total generating capacity, with most of these units connected to approximately 8,000 miles of high-voltage transmission lines. Thirteen tie-lines interconnect New England with its neighbors, New York and the Canadian provinces of New Brunswick and Québec.

In addition to these power-supply resources, New England depends upon significant demand-reducing resources. As of July 1, 2008, approximately 1,700 MWs of demand-reducing resources were registered as part of the ISO-NE demand-response and price-response programs. Customers in these programs reduce load quickly to enhance system reliability or in response to price signals for compensation based on wholesale electricity prices.

The New England Region reached a new record summer-peak load of 28,130 MWs on August 2, 2006, which was due to extreme temperatures and humidity throughout the region. In accordance with ISO-NE operating procedures, demand-response programs were activated to reduce the load, and this action reduced the peak by approximately 640 MWs. In the absence of these programs, the peak load would have been 28,770 MWs. Normal dispatch, considering economics, generation availability, and transactions with neighboring systems, results in multiple intra-New England power transfers of varying direction, magnitude, and duration. The development of over 11,000 MWs of new generation in New England since 1997, without attendant transmission system upgrades, has resulted in situations where surplus generation in one subarea may not be deliverable to other subareas and is not always available simultaneously with other generation in the region as a whole.

Within New England, 13 subsets of the electric power system, called subareas, have been established to assist in modeling and planning electricity resources. Figure F-3 is a simplified model of the system that shows the ISO-NE subareas and three external control areas. The types of analyses that use the subareas include resource adequacy studies and environmental emission studies. More detailed models are used for other types of analyses, including transmission planning studies, and for the real-time operation of the system.

Figure F-3: RSP Geographic Scope of the New England Bulk Electric Power System



Subarea Designation	Region or State	Subarea or Control Area Designation	Region or State
BHE	Northeastern Maine	**WMA**	Western Massachusetts
ME	Western and central Maine/ Saco Valley, New Hampshire	**SEMA**	Southeastern Massachusetts/ Newport, Rhode Island
SME	Southeastern Maine	**RI**	Rhode Island/bordering MA
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine	**CT**	Northern and eastern Connecticut
VT	Vermont/southwestern New Hampshire	**SWCT**	Southwestern Connecticut
BOSTON	Greater Boston, including the North Shore	**NOR**	Norwalk/Stamford, Connecticut
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts	**NB, NY, and HQ**	New Brunswick (Maritimes), New York, and Hydro-Québec external control areas

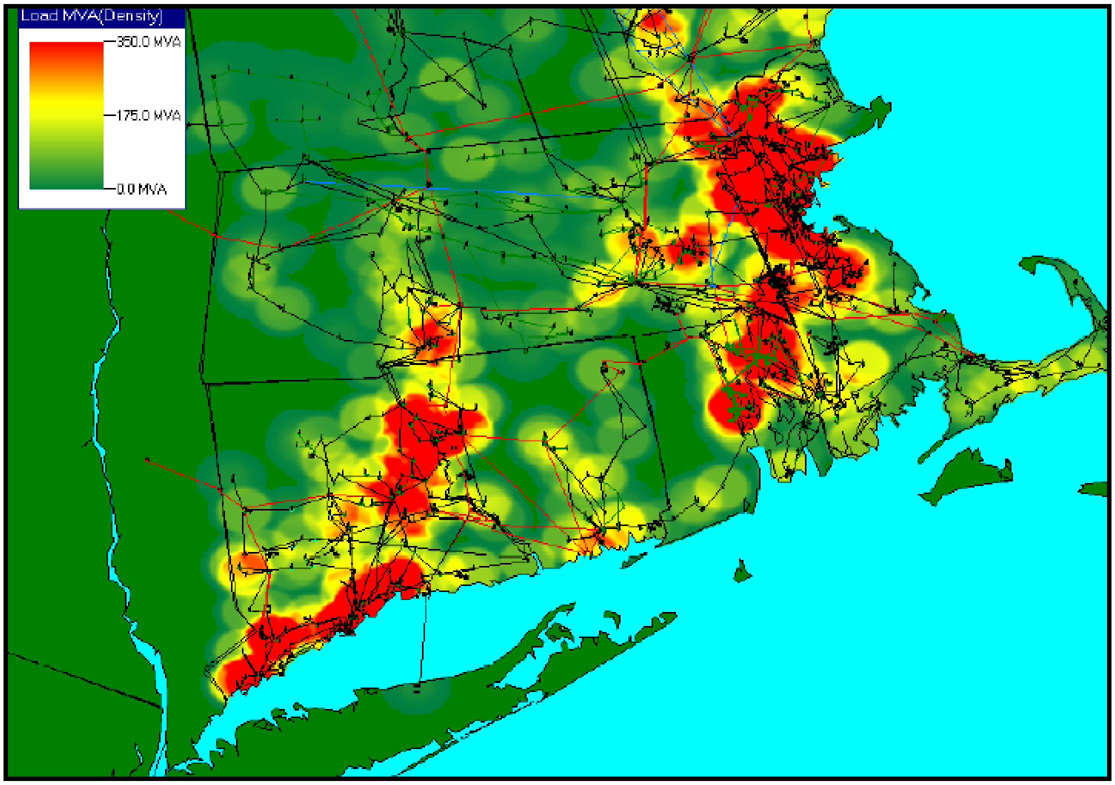
Notes: Some RSP studies investigate conditions in Greater Connecticut, which combines the NOR, SWCT, and Connecticut subareas. This area has similar geographic boundaries to the State of Connecticut but is slightly smaller because of electrical system limitations near the borders with western Massachusetts and Rhode Island. Greater Southwest Connecticut includes the southwest and western portions of Connecticut and consists of the NOR and SWCT subareas. NB includes New Brunswick, Nova Scotia, and Prince Edward Island (i.e., the Maritime Provinces)

F.3 BULK-POWER SUPPLY IN SOUTHERN NEW ENGLAND

The geographic area of southern New England (SNE) encompasses Massachusetts, Rhode Island, and Connecticut. The SNE area accounts for approximately 80 percent of the New England load.

As shown in Figure F-4, the SNE load is concentrated in Boston and its suburbs; central Massachusetts, Springfield, Rhode Island, Hartford, and Southwest Connecticut. These areas of load concentration are called “load pockets” if transmission capability within them is not adequate to reliably import power from other parts of the system, and demand must be met by relying on local generation. Although the Southwest Connecticut area will no longer be a “load pocket” when the Middletown to Norwalk project is in-service, Connecticut as a whole will remain a “load pocket.”

Figure F-4: Southern New England Load Concentrations



The GSRP bridges two of the subareas shown in Figure F-3 – WMA and CT, and addresses the reliability of the power supply to two of the “red” areas of load concentration illustrated in Figure F-4 – the Greater Springfield area and north-central Connecticut, which includes Hartford.

F.4 THE EXISTING TRANSMISSION SYSTEM SERVING GREATER SPRINGFIELD AND ITS TIES TO NORTH-CENTRAL CONNECTICUT

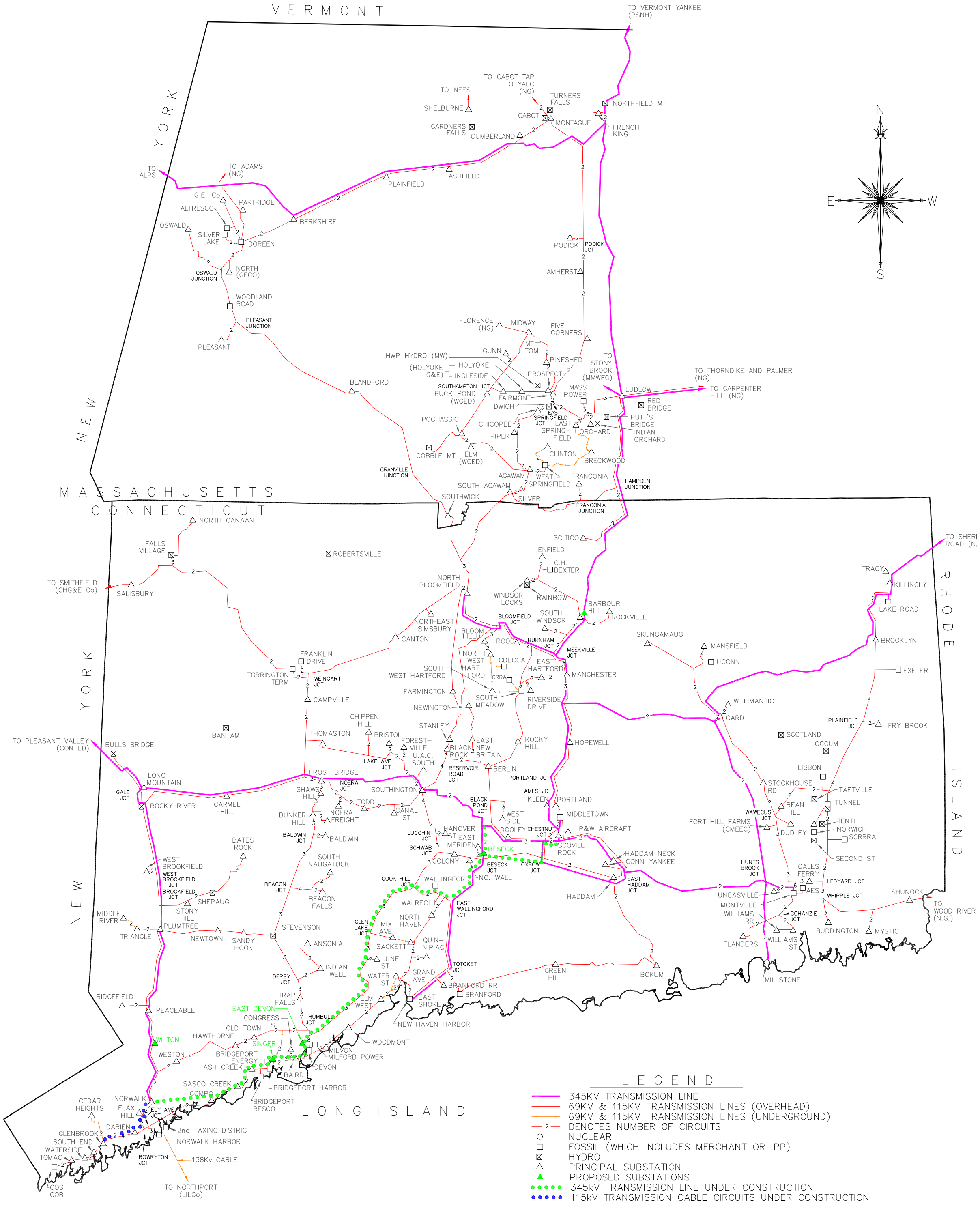
The Springfield study area includes the City of Springfield and extends west to Blandford, south to the Connecticut border, north to Amherst, and easterly to Ludlow. WMECO serves the major portion of the load in this area. Other municipals/utilities that serve load in this area from their own substations are Holyoke Gas & Electric, Chicopee Electric Light, Westfield Gas & Electric, South Hadley Electric, and National Grid.

For this study area, the City of Springfield and surrounding suburbs represents a significant portion of the load. The City of Springfield is a major urban industrial center of metropolitan status at the junction of regional routes between Boston and New York. It is located in southwestern Massachusetts, bordered by Agawam and West Springfield on the west, Chicopee and Ludlow on the north, Wilbraham on the east, and Longmeadow and East Longmeadow on the south. Springfield is 89 miles west of Boston; 25 miles from Hartford, Connecticut; and 134 miles from New York City.

The north-central Connecticut study area borders the Greater Springfield area on the south and extends to the City of Harford and its surrounding suburbs. Hartford is the capital of the State and, after the Boston area, the second largest urban center in Southern New England. Connecticut towns in this study area include Manchester, East Hartford, Hartford, West Hartford, Avon, South Windsor, Windsor, Bloomfield, Simsbury, East Windsor, Windsor Locks, East Granby, Enfield, Suffield, and Granby.

Although the GSRP bears the name of “Greater Springfield,” it necessarily addresses reliability issues in Connecticut. The flow of electricity does not respect state borders. Since key transmission lines in the system serving Greater Springfield terminate at substations in Connecticut, the resolution of the Springfield area problems necessarily involves improvements to portions of the electric grid in Connecticut as well. At the same time, the necessity of resolving these Springfield area problems offers an opportunity for reinforcing the reliability of electric supply to north-central Connecticut and to provide needed improvement in the power-transfer capacity between Massachusetts and Connecticut. The western Massachusetts electric system, including the Greater Springfield area and its ties to Connecticut are shown on Figure F-5 and described in the following text:

Figure F-5: Western Massachusetts and Connecticut Transmission Systems



The 345-kV Bulk Power Supply System in the Springfield Area

The major Springfield area interconnection to the 345-kV bulk power transmission network is at WMECO's 345/115-kV Ludlow Substation. Ludlow is the only major bulk-power substation in the Springfield area where the 345-kV and 115-kV transmission networks interconnect, through large autotransformers that "step down" the voltage from 345 kV to 115 kV. The Ludlow Substation is served by 345-kV lines from both the north and the east. It thus enables bulk power generated in Massachusetts at stations such as Northfield Mountain and Stony Brook, and power imported over WMECO's four 345-kV transmission tie-lines with other systems, to be delivered to the Springfield area's 115-kV transmission system. Ludlow Substation is considered a "strong" source or "hub" for the WMECO 115-kV transmission system.

The 345-kV line serving the Ludlow Substation extends south from there to terminate at the Barbour Hill Substation in South Windsor, Connecticut, and is interconnected from Barbour Hill by a 345-kV line to the Manchester and North Bloomfield Substations in Connecticut. Through these connections, the Ludlow Substation provides a strong source of supply to the Connecticut system, collecting power flowing from Massachusetts, Vermont and New York and transferring it to Connecticut. Under typical dispatch conditions, the 345-kV line from Ludlow may supply 30% of the maximum Connecticut import capability of approximately 2,500 MWs[9].

The Springfield Area 115-kV System

The Ludlow Substation serves the Greater Springfield area load by means of four 115-kV transmission circuits that extend westerly into the Springfield area "load pocket," along different routes, interconnecting with several different substations. Two of these 115-kV lines, after passing through Chicopee, Springfield and West Springfield, connect with the Agawam Substation, and from there to the

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[9] *See*, Needs Analysis, page 12, Table 3-3. Transfer capacity, or import capability, varies with system conditions and is properly expressed as a range, rather than a single point estimate. 2,500 MWs is at the upper end of the range of the aggregate transport capacity across all of the Connecticut interfaces with neighboring electric systems.

South Agawam Switching Station, and then the North Bloomfield Substation in Connecticut. In the event of equipment outages on either side of the state border, these lines can provide transmission support to help maintain the reliability of the interconnected systems. As described in detail in the CEII Appendix, the Springfield 115-kV system includes underground cables of limited capacity and many double circuit lines (two 115-kV overhead circuits supported by a common line of transmission structures).

The North-Central Connecticut Area 115-kV System

The North Bloomfield 345/115-kV Substation is a primary source for bulk power supply to the north-central Connecticut area. The North Bloomfield Substation serves the north-central Connecticut area load by means of three 115-kV transmission circuits that extend southerly into the Hartford area “load pocket,” along similar routes, interconnecting with several different substations. At a location in eastern Bloomfield, two of these 115-kV lines head south toward Hartford and connect with the Northwest Hartford Substation, and from there to the Southwest Hartford Substation and then finally to the South Meadow Substation via a single 115-kV underground cable. Also at this location, a single 115-kV overhead circuit extends easterly toward South Windsor and terminates at the Manchester Substation. At the Bloomfield Substation in Bloomfield, a single 115-kV overhead circuit extends easterly toward South Windsor and turns southerly toward the South Meadow Substation.

As indicated earlier, the North Bloomfield Substation also connects to the three 115-kV circuits from western Massachusetts. These circuits provide a flow-through path between western Massachusetts and Connecticut. In the event of a transmission circuit or equipment outage on either side of the state border, these lines can provide transmission support to help maintain the reliability of the interconnected systems. However, during peak demand periods and heavy power flows into Connecticut, transmission contingencies can cause overloads on these 115-kV transmission circuits with excessive power flows heading toward Connecticut and into the North Bloomfield Substation. In addition, the Hartford 115-kV system includes underground cables of limited capacity. Double circuit line contingencies in north-central Connecticut cause these circuits to overload.

Two other 345/115-kV substations located in South Windsor and Manchester also provide bulk power supply to the north-central Connecticut area load.

The Manchester 345/115-kV Substation serves the north-central Connecticut area load primarily by means of four 115-kV transmission circuits. Two 115-kV circuits head north toward the Barbour Hill Substation and two circuits head west toward the South Meadow Substation.

The Barbour Hill 345/115-kV Substation in South Windsor serves the north-central Connecticut area load primarily by means of two 115-kV transmission circuits. These two 115-kV circuits head northwest toward the Enfield and Windsor Locks Substations.

The transmission circuits between the North Bloomfield, South Meadow and Manchester Substations form a 115-kV loop around Hartford. In addition to direct load serving responsibilities in the Hartford area, this loop also provides a path for power to flows into other Connecticut areas.

F.4.1 Greater Springfield and North-Central Connecticut Area Generation Facilities

Table F-1 lists the larger generation facilities connected to the transmission system in the Greater Springfield area, the dispatch of which affects the reliability of the delivery of power to the area. Total summer capacity listed in Table F-1 is 1,289 MWs.

Table F-1: Greater Springfield Area Generation

Generation	MW
Stony Brook	412
Berkshire Power	280
Mt Tom	147
West Springfield #3	101
MASSPOWER 1	82
MASSPOWER 2	82
MASSPOWER 3	75
West Springfield #1	38
West Springfield #2	38
West Springfield Jet	17
Cobble Mt	17

The Needs Analysis determined that these resources were not sufficient to reliably serve the Springfield area load; and that the Springfield Area would suffer a “load deficiency” in 2009 and through the end of the study period in 2016. Needs Analysis, at 10, 11. Moreover, continued operation of some of the existing units is required to enable the system to withstand contingencies. As ISO-NE has stated in its Regional System Plans (2007 RSP, at p.91):

> Two generators in the Springfield area, West Springfield unit #3 and Berkshire Power, have been frequently designated as daily second-contingency units. These generators, in addition to West Springfield unit #1 and #2, are also needed to support local reliability during peak hours and to avoid overloads, in violation of reliability criteria.

Table F-2 lists the larger generation facilities connected to the transmission system in the north-central Connecticut area, the dispatch of which affects the reliability of the delivery of power to the greater Hartford area. Total summer capacity listed in Table F-2 is 285 MWs.

Table F-2: North-Central Connecticut Area Generation

Generation	MW
South Meadow	138
CRRA	64
Capital District	50
Hartford Hospital	13
Dexter	12
Rainbow	8

The generating units in downtown Hartford provide support to local area loads. However the total power output capability of the combined units is relatively small to the total demand for electricity in the greater Hartford area. Therefore, there is a much greater reliance on the need to import power from outside the area to meets it demand.

F.4.2 Summary of Reliability Deficiencies of the Greater Springfield 115-kV System and Their Impact on the Connecticut System

As described in detail in the CEII Appendix, the 115-kV lines around Springfield, and the 115-kV underground cables that traverse Springfield, serve a double duty of supplying local load and supporting interstate transfers. In fact, under the present system configuration, a portion of the power flowing into Hartford from CL&P's North Bloomfield Substation can come through the Greater Springfield 115-kV system under normal conditions. Under many contingency conditions modeled in accordance with applicable reliability criteria, these power flows cause severe overload and voltage problems on the 115-kV system. The inadequacy of the existing 115-kV lines is compounded because many of the 115-kV circuits in the area share common support structures. Reliability criteria dictate that planners must assume that any contingency that removes one of these circuits from service may also interrupt the other circuit.

These reliability problems exist now, with today's system configuration and loads that have already occurred; and they will continue to grow as the load increases. Accordingly, the improvements proposed to bring the Springfield area system into compliance with applicable reliability criteria include the reconstruction or replacement of approximately 60 miles of 115-kV circuits in Massachusetts that are currently supported by double-circuit structures.

F.4.3 Objectives of the GSRP

The primary objective for the GSRP is to mitigate these problems by accomplishing the following:

- Establish a new 345-kV connection from North Bloomfield Substation in Connecticut to Agawam Substation to Ludlow Substation in Massachusetts, thus complementing the existing Agawam to Ludlow and Ludlow to Barbour Hill to North Bloomfield 345-kV lines to form a 345-kV "loop" through western Massachusetts and north-central Connecticut. This will relieve congestion on the 115-kV transmission system and increase the normal and emergency power-transfer capabilities between Massachusetts and Connecticut;
- Increase Connecticut import capabilities;
- Utilize the existing transmission rights-of-way between Ludlow, Agawam and North Bloomfield Substations;
- Provide an alternate diverse 345-kV source to the North Bloomfield Substation; and
- Establish a new 345/115-kV "hub" west of the Connecticut River and north of the North Bloomfield Substation at the existing Agawam Substation.

F.4.4 The Manchester to Meekville Junction Circuit Separation Project

The power-flow studies performed to develop the GSRP also identified the need for an ancillary Manchester to Meekville Junction Circuit Separation Project (MMP), sometimes also called the Manchester to Meekville Junction Project. As appears in more detail in the CEII Appendix, the modeling of the transmission system with the addition of the GSRP improvements showed that overloads could occur on a portion of the Connecticut 115-kV system, in the event of the simultaneous loss of the 345-kV Barbour Hill-North Bloomfield Manchester #395 circuit and the 115-kV Manchester-Rood Ave. #1448 circuit. The GSRP enables higher flows into Connecticut, and the redistribution of these higher flows in the event of the simultaneous or overlapping loss of these two circuits under certain system conditions would cause other elements of the Connecticut system to overload. Because the two circuits are carried on common transmission structures (for a distance of two miles), planning criteria require that an event interrupting service from either line be assumed to interrupt both of them. Separation of the circuits so that each is supported by its own line of structures eliminates the double circuit contingency and avoids the overload.

F.5 DESCRIPTION OF RELIABILITY ANALYSIS

F.5.1 Initial and Updated Studies

The Needs and Options Analyses were based on load flow simulations using future loads forecast by ISO-NE in 2005 and the solutions were modeled assuming that all of the NEEWS projects were built. In preparation for this Application, NUSCO, with the cooperation of ISO-NE, has performed a new set of power flow studies. These more recent studies are based on the latest (2008) ISO-NE forecast data, and model the impact of the proposed GSRP and the MMP by themselves– without the Interstate Reliability Project or the Central Connecticut Reliability Project in the model. The Rhode Island Reliability Project, for which a siting application has already been filed, was included in the model, but would not have had a significant influence on the pre-GSRP load flow results.

F.5.2 Determination of Future Area Loads

New England utilities rely upon the ISO-NE load forecasts for their transmission planning analyses. These forecasts, as adopted by NUSCO for the planning of the Connecticut transmission system, are regularly reviewed and critiqued by the Connecticut Siting Council in its annual proceeding to review the Forecasts of Loads and Resources by Connecticut utilities and generators.

The ISO-NE load forecast used for transmission planning studies is a 90/10 forecast. This means that the actual peak load has a 10 percent chance of exceeding the forecasted load level and a 90 percent chance of falling below the forecasted load level for each planned seasonal peak. ISO-NE uses this 90/10 demand forecast philosophy to develop its transmission plans to provide greater certainty of reliable electric service under the most severe weather conditions. This approach is consistent with national and regional requirements that contingency testing must include simulated conditions for forecasted load that "reasonably stress" the system (ISO-NE PP3, Section 3). The forecasts look ahead for 10 years and predict both total energy use and seasonal peak loads for New England as a whole, for each of the six New England states, for each of the New England operating companies, and for each substation "bus" within each operating company's system. The complex methodology by which ISO derives these forecasts is publicly disclosed.[10] The ISO "track record" has been very good, although forecasted peak loads tend to occur somewhat sooner than predicted.

The distribution substations in the Greater Springfield area and in Connecticut that are relevant to the GSRP need analysis are identified in Appendix F-1 along with their peak metered loads in 2007 and their projected peak loads for the years up to 2014, reflecting the extreme weather ("90/10") assumptions used by ISO-NE for reliability planning. The power-flow analyses contained in this Application are based on the forecasted load for 2014.

Use of the ISO-NE forecasts in transmission planning studies is complicated by a change in the methodology of accounting for the effects of demand-reducing strategies (variously called Demand-Side Management and Demand Resources) that ISO-NE adopted in 2007. Whereas previously ISO would

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[10] For an ISO-NE presentation of current Load Forecasting Methodologies, see: http://www.iso-ne.com/committees/comm_wkgrps/othr/icsp/mtrls/2006/mar282006/load_forecast_methodologies.pdf ("Ehrlich 2006 Load Forecast Presentation").

reduce its forecasts to account for the predictable effects of certain "passive" DSM programs, ISO then decided to treat new Demand Resources as "capacity" resources, so as to put them on an equal footing with other capacity-related resources (such as new generation) in future Forward Capacity Auctions.

Accordingly, 90/10 extreme weather load forecasts should be adjusted for future DSM effects when modeling future system conditions for transmission planning. Otherwise, such forecasts would likely overestimate future loads and the need for transmission improvements.

F.5.3 Assumed Generator Availability

Stressed conditions for area resources require, at a minimum, an assumption that the largest or most critical generating unit in an area is unavailable. Assessing stressed conditions could also include additional reductions in local generation that accomplish other good utility planning objectives such as (i) facilitating increased power transfers from remote power-supply resources to serve both local and regional load; and (ii) eliminating current or future dependence on out-of-merit local generators.

In particular, power-flow analyses indicate that the dispatch of local generators in the Springfield area, particularly the Berkshire Power (280 MWs) and the West Springfield (177 MWs) stations, have a significant impact on transmission line loading in the area. When operating, these units serve local area load requirements and offer some protection from contingencies affecting access to more remote supply sources, such as the many strong sources available through the Ludlow Substation, by reducing the power flow from the Ludlow Substation through the 115-kV transmission system to feed load centers in Springfield and to support regional power transfers. This protection comes, however, at a price: if their operation is the only way to address certain contingencies, local service and local reliability become dependent on generators that may need to be dispatched out-of-merit. Accordingly, if the Springfield 115-kV system were not upgraded, these "must run" generation conditions would persist, and the Greater

Springfield area would lack adequate flexibility to avoid overloads following certain contingencies and also impact regional power flows.

In constructing dispatch conditions that appropriately reflect “stressed” conditions for the Springfield area, NUSCO worked in coordination with ISO-NE, and together, both took all of the above factors into consideration. After considering a number of scenarios, ISO-NE and NUSCO ultimately determined that outages of the two major generating units located to the west of Springfield had the greatest impact on power flows. The critical units are Berkshire Power and West Springfield unit #3. Only three dispatch scenarios were needed to illustrate their importance. In Dispatch 1, the critical unit outage is Berkshire Power and the units at West Springfield Station. In Dispatch 2, all critical units are on-line. In Dispatch 3, MASSPOWER is assumed to be off-line. All other major units are assumed on-line. Table F-3 contains the dispatch scenarios used in the system impact analyses.

Table F-3: Greater Springfield Area Generation Dispatch Scenarios

Generation	Dispatch 1 MW	Dispatch 2 MW	Dispatch 3 MW
Stony Brook	412	412	0
Berkshire Power	0	280	280
Mt Tom	0	147	0
West Springfield #3	0	101	101
MASSPOWER 1	82	82	0
MASSPOWER 2	82	82	0
MASSPOWER 3	75	75	0
West Springfield #1	0	38	38
West Springfield #2	0	38	38
West Springfield Jet	0	17	0
Cobble Mt	17	17	17

F.5.4 Regional Power-Transfer Limits

Transfer capability is the measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions.[11] A system that can accommodate large inter-area transfers is generally more robust and flexible than a system with limited ability to accommodate inter-area transfers. Thus, transfer capability can be used as a rough indicator of relative system security.[12]

The generation dispatch for units in the Springfield area and the transfer of power between western Massachusetts and Connecticut are key determinants of the power flow on transmission lines passing into and through Springfield toward Connecticut. The allowable transfer level for Connecticut (from New York, Massachusetts and Rhode Island) is currently constrained to a maximum of approximately 2,500 MWs for normal conditions and 1,700 MWs under contingencies. When testing system performance under normal and contingent conditions, NUSCO assumes power flows into Connecticut at these transfer limits.

F.5.5 Modeling of Existing System with "All Lines In"

In its 2008 transmission studies, NUSCO first modeled the existing system with all lines assumed to be operable, but assuming a stressed dispatch due to the unavailability of certain generation. As explained in detail in the CEII Appendix, this simulation of the existing system, with no contingencies, produced overloads in violation of applicable reliability criteria.

F.5.6 Contingency Analyses (N-1) and Results

Following the "all-lines-in" power-flow assessment, NUSCO analyzed the performance of the transmission system between western Massachusetts and north-central Connecticut under contingent conditions (when the GSRP would be in-service) in accordance with national and regional reliability

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[11] http://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf
[12] http://www.pserc.org/cgi-pserc/getbig/publicatio/2001public/tcc_tutorialjuly01.pdf; page 1

standards. A total of 56 contingencies were simulated. The 56 contingencies include both single-circuit contingencies and double-circuit (common structure) contingencies. These pre-project N-1 contingencies are listed in Appendix F-2.

In this N-1 analysis, each contingency on the list was simulated in power flows with all three dispatches. Accordingly, 168 contingencies in total were simulated in these N-1 analyses. The results of these simulations showed serious overloads on many system elements and severe voltage violations that could collapse the Springfield area 115-kV transmission network and potentially cascade outside of the local area. These results are presented in detail in the CEII Appendix.

F.5.7 Contingency Analyses (N-1-1) and Results

Following the N-1 power-flow assessment, the NUSCO planners analyzed the performance of the transmission system in western Massachusetts and north-central Connecticut under N-1-1 contingency conditions in accordance with national and regional reliability criteria. Under these contingency analyses, an initial transmission circuit element is assumed to be out of service for an extended period of time. Only certain transmission elements are considered to qualify at this stage as the cause of an extended outage. They include 345-kV overhead transmission circuits, 345/115-kV autotransformers, 345-kV and 115-kV underground cables that impact the area under study. Each of these elements can have an extended repair time. An N-1-1 analysis does not include 115-kV overhead transmission elements, as they can be repaired in a relatively short period of time. The D1-dispatch was assumed as the basis for this analysis. That dispatch stresses the 115-kV transmission system from Ludlow to Agawam by having the units at West Springfield, Mt Tom and Berkshire Stations off-line. The Connecticut import interface limit was reduced from 2,500 MWs to 1,700 MWs to reflect lower planning and operating levels following a major 345-kV circuit outage.

The contingency deck was repeated for each new base case containing a qualifying initial transmission element out of service. In effect, each “second” contingency was simulated on a power system without the transmission element assumed to have failed. The set of simulated second contingencies was a subset of the initial 56 contingencies. As with the N-1 testing, these N-1-1 contingency analyses resulted in many thermal overload conditions on system elements and voltage problems. These violations of applicable reliability criteria are presented in detail in the CEII Appendix.

F.5.8 Power-Flow Analysis of the Transmission System as Improved By the GSRP Improvements

As explained in the Needs Analysis and the Options Analysis, the GSRP was initially developed on the basis of data available and projections made in 2005. However, it was recently tested using current data and forecasts. To test the transmission system after implementation of the GSRP reinforcements, power-flow studies using current data were performed in 2008. The system as improved by the GSRP and MMP was simulated using the same power-flow cases, including the same dispatches and load levels used to test the pre-project system and reasonably stressed dispatches. A full deck of both N-1 and N-1-1 contingencies was run. The post-GSRP listing of N-1 contingencies is contained in Appendix F-3. As explained in detail in the CEII Appendix, there was only one overload, which occurs in an N-1-1 contingency, and which will be eliminated by the CCRP or, if the CCRP is not built for any reason, by a local area transmission improvement.

F.5.9 Conclusion of Reliability Analysis

In summary, the GSRP is an indivisible, two-state regional reliability project which:

- Provides a second 345-kV transmission circuit between the Ludlow Substation and the North Bloomfield Substation;

- Increases the power transfer capability between Massachusetts and Connecticut by providing a second 345-kV circuit between the Ludlow and the North Bloomfield Substations;
- Increases reliability by the formation of a 345-kV loop which provides two 345-kV sources to the Agawam and the North Bloomfield Substations;
- Increases Connecticut import capabilities;
- Utilizes the existing transmission rights-of-way between Ludlow, Agawam and North Bloomfield Substations;
- Provides an alternate diverse 345-kV source to the North Bloomfield Substation;
- Establishes a new 345/115-kV "hub" west of the Connecticut River and north of the North Bloomfield Substation at the existing Agawam Substation; and
- Eliminates line overloads following multiple first and second contingency events.

The MMP enhances the reliability improvements of the GSRP by eliminating overloads that could occur as a result of a second contingency following the loss of the proposed new 345-kV North Bloomfield to Agawam circuit.

F.6 CONFORMITY OF THE PROPOSED PROJECTS TO A LONG-RANGE PLAN FOR EXPANSION OF THE ELECTRIC POWER GRID

The NEEWS Plan is itself a long-range plan for the expansion of the Southern New England electric power grid. It has been developed through intensive work and study over a period of approximately five years, and has been designed to address all of the major problems of the southern New England bulk-power supply system. In addition, the NEEWS plan has been closely designed and integrated with the nearly completed 345-kV transmission loop in SWCT. Although some additional improvements of the 115-kV system in southern New England will be needed in the next several years, the 345-kV components of NEEWS, if built as proposed, should not require reinforcement for the indefinite future.

F.7 STATUS OF THE OTHER NEEWS PROJECTS

The Rhode Island Reliability Project was proposed in a filing with the Rhode Island Energy Facility Siting Board on September 8, 2008. The Interstate Reliability Project is expected to be proposed in late 2008. The Central Connecticut Reliability Project is expected to be proposed in mid 2009.

F.8 IN-SERVICE DATE

The GSRP is expected to be in-service in late 2012 or in 2013.

Appendix F-1

Load Forecast Data

Appendix F-2

Pre-GSRP N-1 Contingency List

Appendix F-3

Post-GSRP N-1 Contingency List